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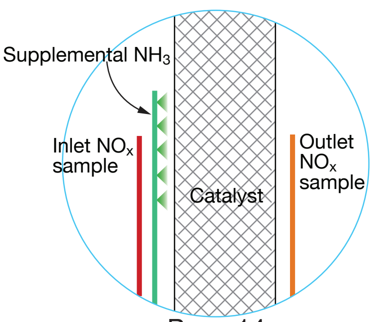

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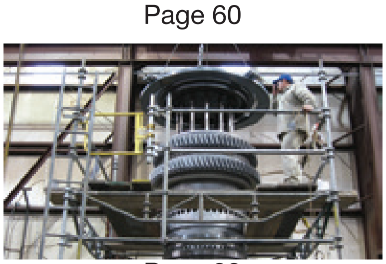
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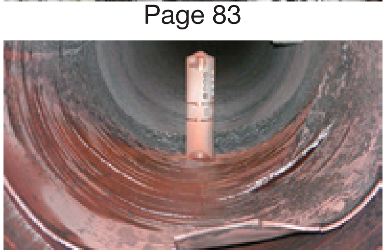
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Features

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Miscellany

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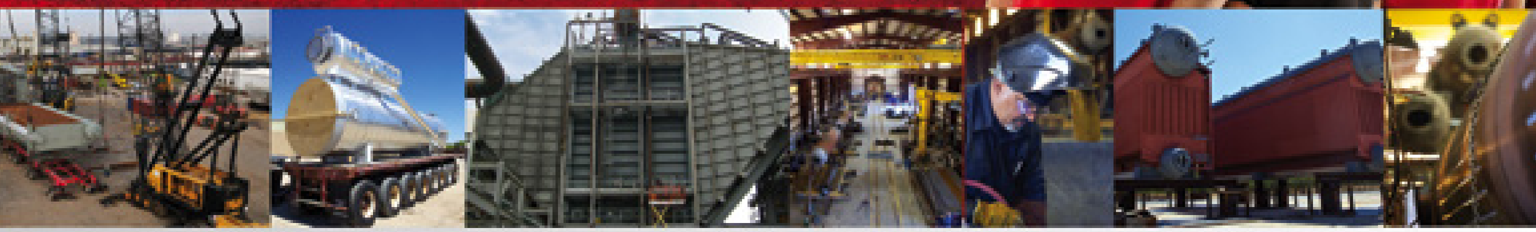

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Integrating shop tours, 'classroom' sessions increases the value of user group meetings

You could call this the "Year of the Shop Tour." Most of the user groups dedicated to gas-turbine owners and operators are getting out of the classroom for a half day or so at their annual meetings to see firsthand what's going on in the manufacturing centers and repair shops serving the industry. Hundreds of millions have been invested in expanding and upgrading these facilities over the last several years to satisfy global demand and to transition, to the degree possible, from worker-intensive processes to automated machining centers, high-tech nondestructive examination, etc.

A visit to a modern manufacturing center dispels the notion that skills lost through worker retirement were going to cripple the industry. To the contrary, retirements may have facilitated the transition to hands-off manufacturing controlled by sophisticated software and machine tools. This is not to say skilled machinists are no longer needed; they most certainly are. However, you need fewer of them today than in the past.

If you have been in the industry for three or four decades and haven't visited a shop within the last 10 years or so, you may find it almost unnerving to stand on the floor of a modern turbine/generator manufacturing center and watch product flow, with a minimum of human intervention, into special shipping containers to protect against damage. Relatively few workers are visible and the facilities are spotless, well lit, air conditioned, and generally quiet, with no dust or odors in the air.

Manufacturers are flag-waving proud of their new shops, tooling, and capabilities. They have invited user groups to hold their annual meetings nearby, thereby enabling tours. In most cases, the tours are conducted in groups of about 10 to 15 users with headsets provided to assure that the finer points of a particular process are not missed by anyone.

Direct involvement of shop personnel on most visits is particularly valuable. Sanitized, canned presentations by a tour guide are old school. Today you get to listen, for example, to the coating specialist at his or her workstation on what they do to assure quality of your hot-gas-path (HGP) parts; you have the opportunity to ask technical questions and get the answers you need to make better decisions for your plant and company. Worker pride is clearly in evidence at every tour stop. Not attending a user group meeting with a planned tour is a valuable opportunity lost.

A sampling of shop visits conducted, and scheduled, by users groups this year include the following:

- CTOTF Spring Turbine Forum: Alstom's Midlothian turbine/generator shop, conducted.
- 7F Users Group: Pratt & Whitney Power Systems' San Antonio manufacturing and repair facility, conducted.
- 501D5-D5A Users: Liburdi Turbine Services Inc's repair facility, Pioneer Motor Bearing Co's repair shop, Siemens Energy Inc's facilities for manufacturing and repair of gas and steam turbines and generators, and components for those machines. All conducted.
- Frame 6 Users Group: GE Energy's turbine and generator manufacturing and repair shop in Greenville, SC, conducted.
- CTOTF Fall Turbine Forum's upcoming visit to Solar Turbines' San Diego manufacturing and repair center. Access www.ctotf.org for details.
- 7EA Users Group's upcoming visit to GE Energy's turbine and generator manufacturing and repair shop in Greenville, SC. Access http://ge7ea.users-groups.com for details.
- Although not a shop tour, the ACC Users Group will be visiting in-service air-cooled condensers during its late-September meeting in Gillette, Wyo. There are half a dozen ACCs operating in the Gillette area with O&M experience going back four decades. Access www.acc-users.org.

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California clean energy, and the rest of the West

By Jason Makansi, Pearl Street Inc

Arguably, California is attempting to implement the nation's most ambitious clean energy plan. That strategy is a convergence of the following elements:

- A 33% Renewable Portfolio Standard (RPS) by 2020.
- A state carbon-reduction and cap-and-trade program (AB32).
- Significant incentives and subsidies for distributed energy and storage, and demand management and efficiency.
- An electric vehicle (EV), natural gas, and transportation infrastructure development program.
- A clean jobs program.
- Add to the items above, new emissions and thermal-discharge restrictions on existing fossil plants, and some of the nation's most onerous environmental, ecological, and land-use policies.

But the state has never existed as an island in the context of energy. Some of its water comes from other states, and water is of course critical to electricity production. Hydropower from the Pacific Northwest provides a significant share of the state's electricity. An insignificant amount of natural gas is sourced in California, but the state has the third highest consumption of that fuel for electricity production.

Some of the country's best wind is located offshore California, yet few leaders, if any, are discussing how to harness it. Two nuclear plants have operated in the state for decades but no one talks about building new ones. And, despite what you may read about the California exodus, it's still the most populous state in the nation.

Where is all the clean energy going to come from? Neighboring states, you say? Almost all of them face compliance with their own RPSs and other clean-energy goals, though none nearly as aggressive as California's (Fig 1). And California's desire to reinvigorate its economy through clean energy means that it is restricting clean energy imports to create in-state jobs.

The impact of California on the "rest of the West" is a complicated puzzle with many moving pieces and parts, contradictions, regional synergies, and opportunities. Pearl Street Inc and PGS Energy Training have developed an insightful workshop to help executives and managers at generating plants and headquarters locations understand the ramifications, nuances, opportunities, and pitfalls of the state's clean-energy policy.

What follows are excerpts from the first workshop, "California Clean Energy and the Rest of the West," held in April in Sacramento. It will be updated and repeated October 10-11 in Portland (visit http://www.pgsenergy.com/classroom-seminars for details). Contact Jason Makansi (jmakansi@pearlstreetinc.com) if you have any questions.

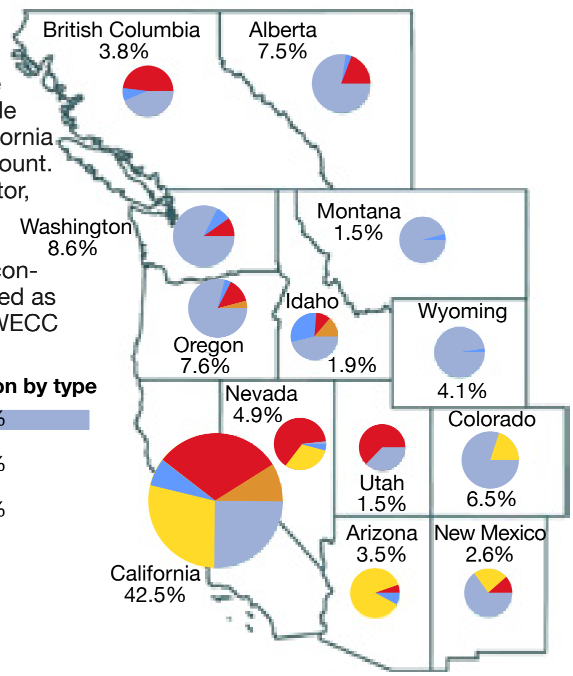
One can envision many different scenarios for how Western US energy flows will change over the next 10 years. Yet one thing is almost certain: Gas-fired gas turbines will play a bigger role in meeting the state's challenges.

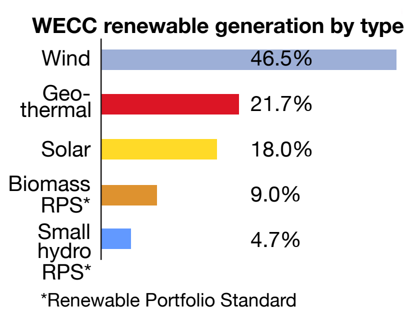
State polices up close

Some of the pieces and parts of the California strategy deserve a closer look. One interesting element, especially for large combined-cycle advocates, is the state's goal to have 20,000 MW of new renewable capacity. The lion's share, 12,000 MW, is intended to be localized distributed energy systems up to 20 MW each in size. Generous incentives are available for those projects.

The state has also defined multiple renewable energy zones and 13 critical transmission projects to bring distributed power to load centers. Thus, California isn't just pursuing an ambitious clean-energy plan, it seeks to convert the system from one traditionally dominated by long wires

1. The Western Electricity Coordinating Council (WECC) expects to generate 165,000 GWh from renewable resources in 2020, with California producing 42.5% of that amount. The second largest contributor, Washington State, would produce only one-fifth of California's total. Note that conventional hydro is not included as renewable energy. Source: WECC





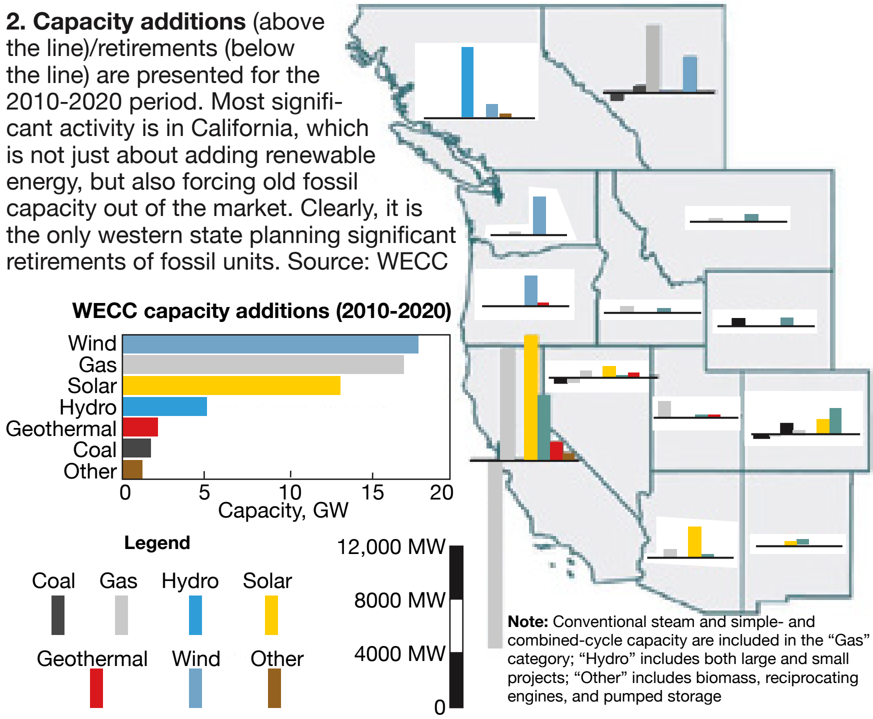
and large, centralized power stations. This would, to use a cliché, break the paradigm.

AB32, the carbon reduction legislation, seeks to reduce greenhouse gases by 20% of 1990 levels by 2050. In part to achieve this, 2000 MW of contracted coal capacity will be eliminated. But the bigger and more worrisome piece of AB32 is imposing new thermal discharge restrictions (AB1318) that could force out 13,000 MW of fossil capacity (Fig 2). AB32 doesn't just cover power stations either; all facilities for which GHG emissions exceed 25,000 tons/yr are governed by the legislation, which reportedly captures 600 facilities.

Do the math: 15,000 MW of fossil gone, replaced by 20,000 MW of renewable energy. Looked at another way, the state plans to replace 15,000 MW of largely amortized fossil plants, which typically can operate at capacity factors of 50%-90%, with systems that operate at 30%-40% capacity factor, and are highly variable—daily, weekly, and seasonally. This will significantly change the operating characteristics of the grid.

Two other pieces of the strategy deserve mention:

- AB2514 encourages the development of energy-storage technologies, although most of the distributed storage technologies are not yet ready for commercial deployment.
- The California Electric Vehicle Collaborative seeks to have up to 1-million EVs on the road by 2020; plus, vehicles fueled by compressed natural gas.



2. Capacity additions (above the line)/retirements (below the line) are presented for the 2010-2020 period. Most significant activity is in California, which is not just about adding renewable energy, but also forcing old fossil capacity out of the market. Clearly, it is the only western state planning significant retirements of fossil units. Source: WECC

Note: Conventional steam and simple- and combined-cycle capacity are included in the "Gas" category; "Hydro" includes both large and small projects; "Other" includes biomass, reciprocating engines, and pumped storage

Regionalism: A federal goal?

When it comes to electricity production and delivery, the federal government clearly has been pushing states and their utilities towards a regional approach for many years. Five years ago, the FERC essentially mandated, through Order 890, that utilities, or at least transmission providers, participate in Regional Transmission Organizations (RTOs), all of which include markets to promote competition, in varying degrees, for wholesale electricity purchases and services. In 2001, FERC also attempted to regionalize electricity through "standard market design," an initiative which ultimately failed.

FERC's latest initiative, Order 1000, (1) requires transmission entities to create regional transmission plans; (2) seeks to make transmission development more transparent and therefore more susceptible to competitive forces; (3) eliminates the right of first refusal for incumbent utilities to develop transmission; and, most importantly, (4) allows public policy goals, not just reliability and "just and reasonable rates," to be included in transmission planning. Costs can be allocated across the RTO or independent system operator (ISO) "footprint" as long as they are commensurate with estimated benefits.

The Obama Administration also has created a Rapid Response Team for select interstate transmission projects to coordinate among all the federal agencies with something to say about where, how, and when transmission lines can be permitted. DOE has funded regional grid evaluations like the Western Renewable Energy Zone (and the Eastern Interconnection Planning Collaborative), and has provided loan guarantees for clean-energy projects—including wind, solar, and nuclear.

The Dept of the Interior is streamlining federal permitting for renewable energy. Congress has done its part by introducing the Clean Energy Standard Act of 2012, which seeks to establish a federal clean-energy credit trading program. The Western Governors Assn also has a Renewable Energy Zone Initiative.

These and other policy initiatives pave the way for greater availability and integration of clean energy flows among California and its neighbors. Or do they?

Countervailing forces

One of the problems with regionalism is that there are no regional governments. There can be agreements, coordination, and strategies but in the end, only the state or the feds can pass laws—and all can be challenged in the courts.

Here are a few other observations about California and the West:

- California has a functioning electricity market and wholesale competition. The other western states, and California as well, participate in the Western Electricity Coordinating Council, which does not promote competition to nearly the same degree.
- California is creating its own carbon cap-and-trade system. The state could be disadvantaged because its neighbors are not imposing the same costs on their state economies.
- If costs rise significantly in California because of its clean-energy policies, then neighbors could benefit when jobs shift from high-cost California to lower-cost states.
- If the transmission system isn't expanded, the clean energy isn't going to get to where it is needed.

California's own Clean Jobs program overtly biases development towards in-state. And the fine print of the RPS directs that in the later years of the program, towards 2020, clean-energy imports will be restricted. The strategy is to allow imports in the early years until other infrastructure is in place so that the state can meet more of its needs within its borders. Ultimately, 75% of the RPS must be met with "in-state bundled transactions" (renewable energy credits plus capacity). Owner/operators are not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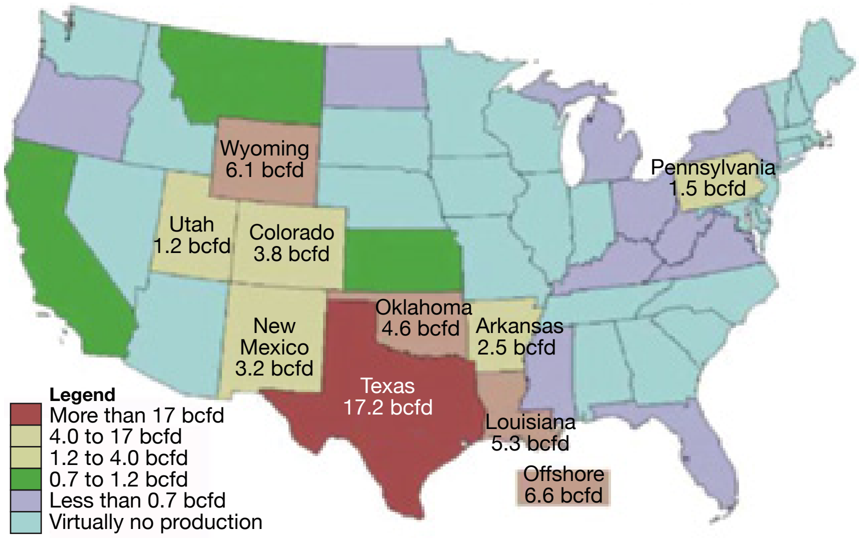

3. California is one of the smallest producers of natural gas but the second largest consumer, a dichotomy that has to be reflected in expanding gas delivery to the state. Total production for the Lower 48 is 56.7 billion ft^3/day (bcfd). Source: NERC

likely to build facilities in neighboring states for an opportunity to sell into California for only a few years.

Then there are the hard macro-realities of the electricity business today. While the costs for renewable energy have been declining, the historically low price of natural gas essentially has put every other generating option in jeopardy. Electricity demand destruction, a consequence of the recession, an anemic recovery, and moderate weather patterns, means that utilities are not making much money, so there is less money to invest and less need for capacity. Finally, most governmental entities, whether federal, state, or city, are in debt up their eyeballs.

In short, it's probably not the best time to force amortized powerplants to shut down and replace the capacity with more expensive clean energy.

Unfortunately, there are other forces that are likely to restrain the state's ambitions in clean energy. First, California is in the midst of a budgetary crisis, and cuts are going to come from somewhere. Second, the desire to restrict out of state renewable energy flows to grow the state's economy may not hold up to a challenge based on the Interstate Commerce Clause.

Third, the electric and gas transmission systems must be expanded (Fig 3) if renewable energy from the region is to fulfill its promise and natural gas fired plants are going to manage the renewable energy variability. Fourth, costs to comply with the carbon reduction laws may derail economic growth, and electricity demand, if companies decided to close up shop instead or transfer manufacturing and production capacity to other facilities. Finally, an oppositional political movement is waiting in the wings for a change in administration.

Train wreck ahead?

California policy-makers could manage this dynamic and delicate policy puzzle in such a way that its economy grows from clean-energy manufacturing and clean-energy facility construction without high energy costs that would drive business out of the state. The regional development of clean energy could occur in tandem, so that California gets what it needs in terms of imports and the rest of the states meet their own goals. Deployment of electric vehicles and transportation networks also escalate electricity demand, although latest projections show that EVs shift demand more than they grow it. But to have all this unfold smoothly would be a feat of politically epic proportions.

It is just as easy to envision a different scenario—one in which the needed transmission lines are not permitted and built, utilities delay procurements for new capacity, an immediate need for jobs takes precedence over cleaner air, other states revert to parochialism because of lack of economic growth, and changing political dynamics result from the upcoming presidential election. A close analysis shows that the Obama "energy strategy," at least when he first came into office, is quite similar to one California is pursuing.

Another alternative scenario might be that state's economy begins to grow fast and new capacity has to be added quickly.

Hedging your bets

Given all of this uncertainty, if you had to hedge your bets as a planner or industry executive, what would you do? Well, your ace in the hole is probably going to be a gas-fired plant. Here's why:

- If renewables come on stream in a timely manner, then the gas plant will be used to fill in around the intermittent availability of solar and wind.
- If renewables do not come on stream in a timely manner, then you can run the gas plant at higher capacity factor, perhaps buying Renewable Energy Credits (RECs) to cover your carbon emissions, or arguing for an extension on compliance with the RPS.
- If electricity demand begins to rise unexpectedly, a gas-fired plant can be permitted and built faster than any other option, even in California.
- If you needed peaking capacity initially, you could install a simple-cycle gas turbine/generator and add the steam bottoming cycle at a later date—if demand dictated.

As one California utility manager put it, at least you can take a gas-fired plant and a 10-year contract for favorable and predictable gas prices to your investment committee and/or the PUC.

It pays to keep in mind that 2020, the deadline for the 33% RPS, is only seven and a half years away. That's the equivalent of a California minute in utility planning time scales.

Meet the workhorse

All things considered, then, California and the West are in for a mini-boom of gas-fired plant construction and the evidence is already there (access "By the numbers," CCJ 1Q/2012, at www.ccj-online.com). One OEM calls its new flexible combined cycle "a high-efficiency combined cycle with a smaller peaker inside." First commercial units, which feature a larger compressor with multiple rows of variable guide vanes, are operating this year, reportedly able to meet the following performance specifications:

- Turndown to 40% of base-load capability while remaining emissions compliant (excluding CO_2).
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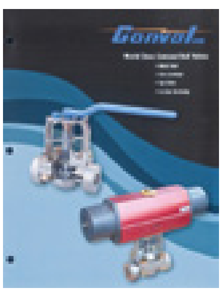

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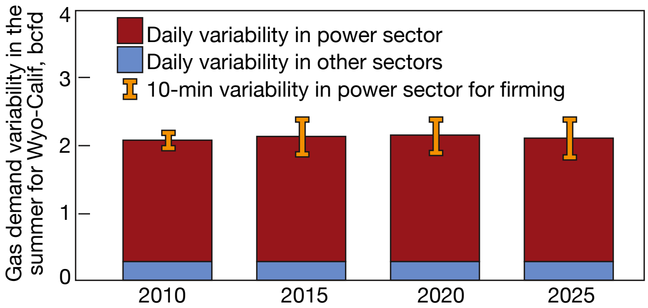


4. For gas turbines, "following the wind" means more than cycling; it also means that the gas delivery system must handle more variability. Source: INGAA Foundation

rises (which normally reduces efficiency and capacity).

All of this reportedly with no impact on service life. All of the major turbine vendors are pushing models with similar capabilities.

During the workshop, these performance specs got a chuckle from two combined-cycle plant operators in the room. They both contend that their facilities achieve the same or at least similar flexibility in following load. "Flex" or "shaping power" gas turbines, they said, is sales language. Adding a clutch between the gas turbine and generator allows the unit to also operate in the synchronous-condenser mode and provide reactive power to the grid as an ancillary service.

Gas/renewable integration

While it may seem fairly straightforward to simply plunk down new gas turbine systems, it isn't. Most people are familiar with the difficulties acquiring permits in California.

But another issue experts hadn't been focused on until recently is delivering the fuel gas to powerplants in a manner that matches expected operating profiles of the new plants. The massive gas transportation infrastructure in this country is a storage medium of sorts, but it has been built around seasonal demand profiles.

If gas turbines are to "follow the wind or sun" then their daily operating profiles will change substantially. In fact, two combined-cycle plant operators in the workshop confirmed that their dispatch profiles had changed to reflect renewable energy systems serving the system.

Thus, natural-gas delivery has to meet new operating profiles. At least one study shows that the 10-min variability in the power sector for firming gas delivered from Wyoming to California could more than double (Fig 4). NERC is sufficiently worried about such issues, and the impacts they may have on electric system reliability. It is considering new reliability standards, monitoring and tracking systems, lines of communication, and outage coordination between pipeline operators and powerplant owner/operators.

The California Independent System Operator (CAISO), not surprisingly, is also worried about the flexibility of the existing fleet to handle variable renewable energy. One reason is because AB1318 could knock out much of the existing oil/gas-fired boiler fossil fleet that has cycling capability. CAISO expects regulation up/down requirements to change considerable, even under the older 20% RPS mandate.

New approaches abound

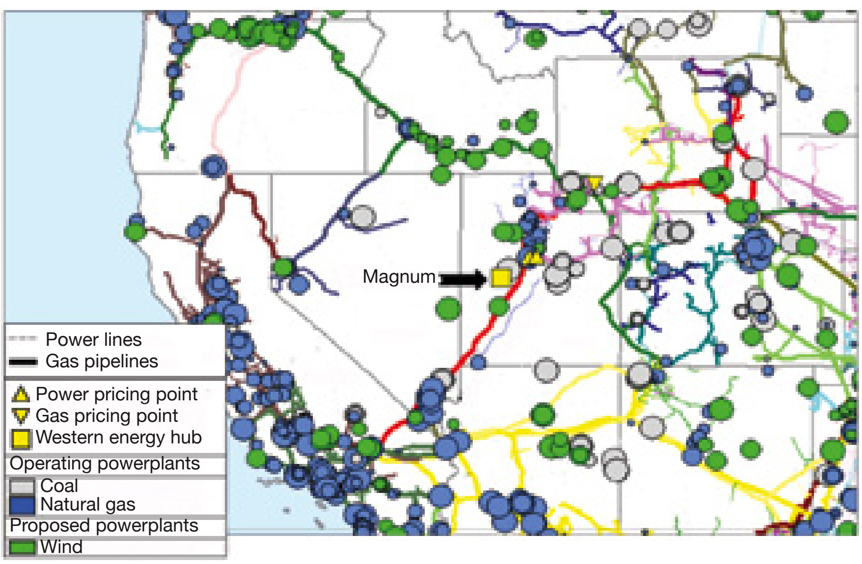
There are many ways to balance renewable energy on a regional basis. Since utilities and their stakeholder public utility commissions (PUC) overwhelmingly converge on the least-risk, least-cost approach, most of these may not be implemented for many years. However, they are still worth a mention.

1. Western Energy Hub. One private developer seeks to combine cavern-based natural-gas storage and compressed air energy storage (CAES) at a location near the Intermountain Power Plant in Utah which feeds directly to Los Angeles Dept of Water & Power via a dc transmission line. Given the discussion above regarding gas delivery, and knowing that Wyoming is fossil-fuel and wind rich, and Colorado is developing its wind resources at a rapid clip, it's easy to see how such a facility could intermediate natural gas, renewable energy, and RECs flows into and out of California (Fig 5).

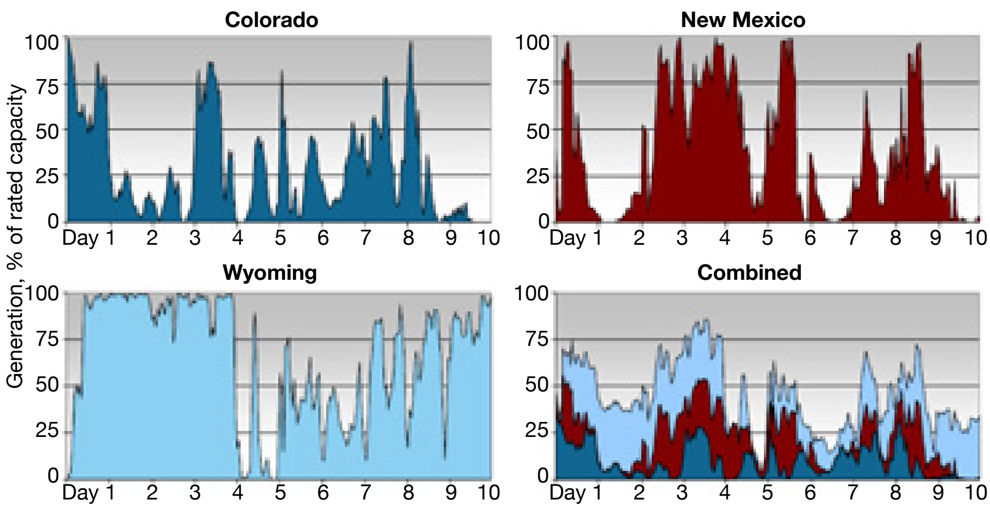
2. Pumped storage. Virtually all the energy storage in the world (99%) serving electricity grids comes from pumped hydro storage (PHS). Over 40 new facilities, including those proposed and those which have applied for a preliminary FERC permit, dot the western planning map. Utilities are very familiar with this technology and the latest models incorporate variable speed technology to make them even more responsive and flexible. Biggest challenges facing PHS are development and construction schedules that are often seven to 10 years, and high capital costs. However, from a life-cycle cost point of view, they are very attractive.

3. Regional coordination. Wind turbines operate within "ideal conditions" only 10% of the time. However, if grid operators and wind facility operators closely coordinated supply and demand, combined performance data, meteorological data, statistical models, advanced real-time communications, and improved sensor technologies, renewable energy flows could be balanced with demand on a wider regional basis.

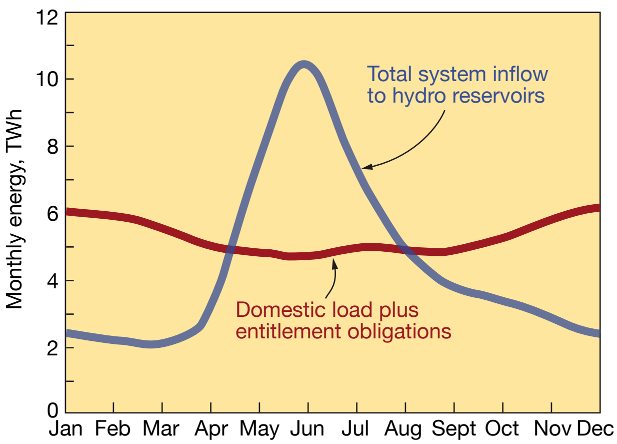
You could add to this a layer of demand management on the distribution side of the electric system. While in theory, this approach probably involves the least cost in new infra-



5. Magnum Energy Hub, adjacent to the Intermountain Generating Station in Utah, could be strategically located for mediating electricity, gas, and RECs flows between California and the West. Source: Energy Velocity



6. The idea of integrating wind energy flows across the West as a means of reducing variability is an interesting concept, but studies indicate that you don't necessarily eliminate the peaks and troughs, as shown in the combined profile (lower right) for the period Oct 27, 2011 through Nov 5. Note the geographically diverse wind profiles for Colorado, New Mexico, and Wyoming. Source: BC Hydro



7. A massive hydro storage reservoir in British Columbia could serve as a "super pumped storage" facility, providing shaping and firming services to the Western US. The Midwest ISO is evaluating a similar arrangement with other Canadian provinces. Source: BC Hydro

structure, it is difficult to envision how such coordination could be achieved on a practical basis. There is also evidence that the wind distribution among the different states doesn't match well, anyway (Fig 6)

4. Cross-border hydro. Perhaps the most intriguing idea for regional management lies to the north. BC Hydro has a large multi-year hydro storage system associated with approximately 70% of the utility's energy production. In essence, BC Hydro's system could release water when needed and send electricity south, providing shaping and firming services to the Pacific Northwest and California (Fig 7). CCJ

SCR performance management: AIG tuning, catalyst life forecasting

By T D Martz, L J Muzio, and **R A Smith,** Fossil Energy Research Corp (FERCo)

Many gas-turbine "bubble" units installed between 2000 and 2004 are operating with their original charge of SCR catalyst. These units have outlived the original catalyst warranty (typically three years) and have benefitted from a combination of conservative design and good luck.

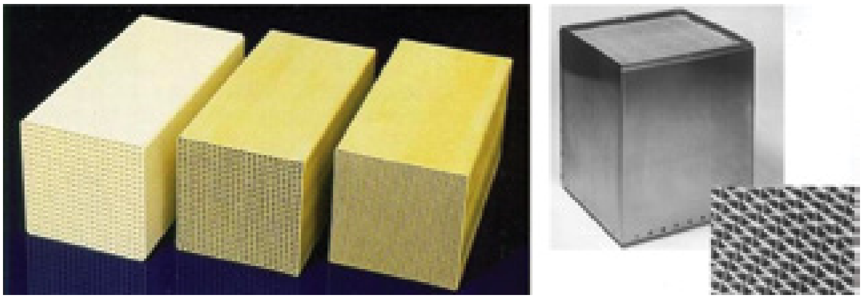
However, as these systems reach the decade mark, the design margins have diminished because of gradual (and inevitable) deactivation of the catalyst with age. As the catalyst nears its end of life, ammonia slip begins to increase exponentially. This catches many operators by surprise. They realize much too late that they are close to exceeding their ammonia slip limit and in danger of a costly forced outage.

There are practical steps operators can take to avoid this scenario, including these:

- Check and optimize the NH_3/NO_x distribution regularly. Improving distribution by tuning the ammonia injection grid (AIG) can reduce ammonia slip, thereby extending catalyst life.
- Forecast the life of your catalyst by regularly monitoring both its activity and ammonia slip. As the catalyst ages, the frequency of these measurements may need to increase.
- Implement a catalyst replacement plan so you are prepared to act before the slip limit is exceeded. Catalyst life forecasting is an important part of this plan. It is also helpful to clarify expectations regarding replacement-catalyst lead time, storage, and installation well in advance of placing an order.

SCR fundamentals

There are two primary types of SCR catalyst used today for stationary gas-turbine (GT) applications: extruded ceramic honeycomb and corrugated mat (Fig 1). Both are homogeneous, meaning the catalytic material is distributed uniformly within the catalyst substrate material.



1. Two types of SCR catalyst typically are used in gas-turbine applications: extruded ceramic honeycomb (left) and corrugated mat (right)

The catalytic material, similar in both types of catalyst, consists of vanadium pentoxide, titanium dioxide, molybdenum, and tungsten. Catalyst pitch sizes (technically speaking, cell hydraulic diameter) can be as small as $1/16$ to $1/8$ in. for gas-fired systems because there is no ash in the flue gas. Manufacturers of extruded ceramic honeycomb catalyst include Cormetech Inc, Ceram Environmental Inc, and Johnson Matthey plc; corrugated mat catalyst is manufactured by Haldor Topsoe A/S and Hitachi Zosen Corp.

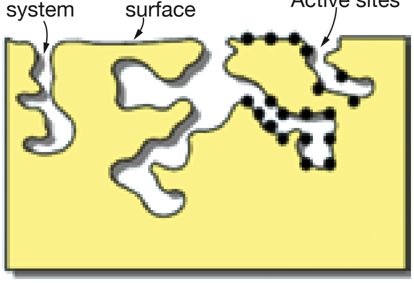
Some early GTs came equipped with a heterogeneous "washcoat" SCR catalyst, which has a thin coat of catalyst material layered on top of extruded ceramic substrate. Washcoat catalyst by nature has less catalytic material per pound than homogeneous catalyst and is prone to premature deactivation. Most GT operators have replaced their washcoat catalyst with a homogeneous product.

Catalytic mechanism. In the presence of oxygen, the selective reaction of ammonia and NO_x will happen on its own at temperatures around 1750F. This technology is called selective non-catalytic reduction of NO_x, or SNCR, and is often used in fossil-fired boilers at the furnace exit to provide modest NO_x reduction (20% to 30%). To promote this reaction at temperatures below 1000F, a catalyst is required; hence the term selective catalytic reduction, or SCR.

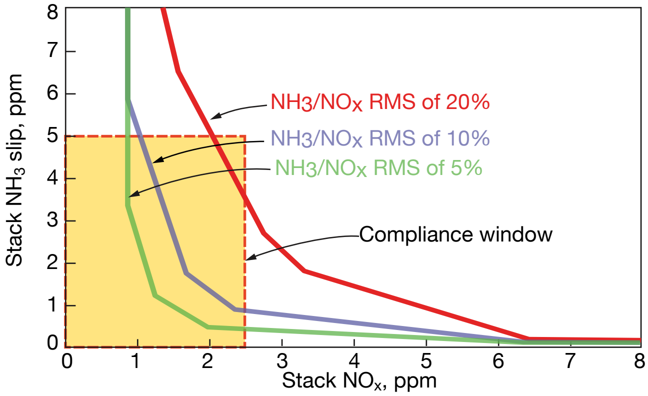
The primary SCR reactions are represented by the following equations:

$$4NH_3 + 4NO + O_2 \rightarrow 4N_2 + 6H_2O$$
$$6NO_2 + 8NH_3 \rightarrow 7N_2 + 12H_2O.$$

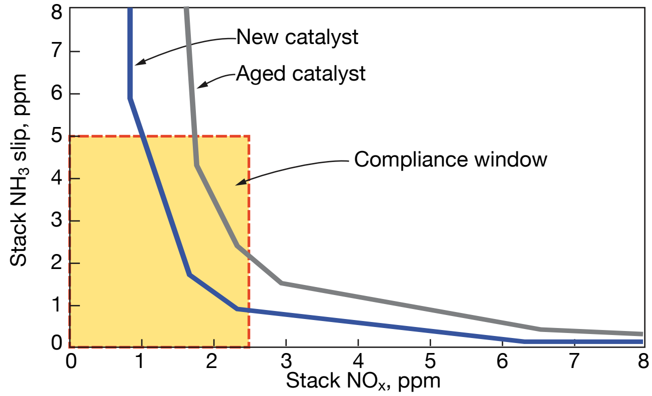
These reactions occur on the catalyst surface, so a large surface area is desired to minimize the catalyst volume. The substrates used for SCR catalyst have an inherent system of pores to provide the surface area required. Note that catalyst material is not consumed during the reaction. Operating the SCR system at a lower or higher NO_x reduction level will not increase or decrease catalyst life. In gas-fired applications, life is determined primarily by the amount of



2. Catalyst active sites are poisoned (deactivated) by alkali metals such as sodium, from water injection, and phosphorous, from lube oil



3. Uniformity of the NH_3/NO_x profile across the catalyst face impacts ammonia slip. Data for new catalyst illustrate that the lower the RMS value, the more uniform the profile. Catalyst vendors typically would require an NH_3/NO_x RMS of 10% to achieve the compliance window shown (less than 2.5 ppm NO_x and 5 ppm NH_3 slip at the stack)



4. Ammonia slip increases as catalyst deactivates. Curves compare slip for new catalyst with an NH_3/NO_x RMS of 10% to the same catalyst that has lost 20% of its activity over time. Tuning of the ammonia injection grid (AIG) often can improve the NH_3/NO_x profile to recover some of the lost slip margin

catalyst poisons there is in the flue gas.

Deactivation. Active catalyst sites (Fig 2) are poisoned by alkali metals such as sodium (from water injection) and phosphorous (from lube oil). The rate of catalyst deactivation depends on the concentration of these poisons in the flue gas. For GT applications, the levels are low, generally resulting in deactivation rates of less than 5% per 10,000 hours of operation. This enables a new catalyst charge to perform effectively well beyond the typical three-year warranty period.

The NH_3/NO_x ratio is the molar ratio of the injected ammonia over the NO_x at the catalyst inlet. The equations above show that the primary SCR reactions require only one mole of NH_3 to remove one mole of NO, and about 1.33 moles of NH_3 to remove one mole of NO_2. Depending on the fraction of NO_2 in the overall NO_x concentration (typically about 20% for a gas turbine system), no more than about 1.1 moles of NH_3 are needed per mole of NO_x to make these reactions happen.

If the concentration of NH_3 is higher in localized regions on the catalyst, then the excess ammonia will "slip" through the catalyst in these regions and move on to the stack. Thus the uniformity of the NH_3/NO_x profile across the catalyst face is critical to the SCR process.

Uniformity of the NH_3/NO_x profile is quantified by performing measurements on a grid of points that are on equal areas (to the extent possible). The standard deviation of the measured points is taken and normalized to the average. The result is defined as the RMS value, and is expressed as a percentage of the mean. Note that the NH_3/NO_x profile is more uniform at lower RMS values than at higher ones.

Fig 3 illustrates the dependence of ammonia slip on the NH_3/NO_x profile uniformity when 90% NO_x removal is required. The FERCo SCR process simulation model was used to generate these curves for a system assuming 25 ppm NO_x at the SCR inlet, 2.5 ppm NO_x at the stack, and an ammonia slip limit of 5 ppm.

For a given stack NO_x value, ammonia slip increases as the NH_3/NO_x RMS value increases. As a frame of reference, catalyst vendors typically require 10% NH_3/NO_x RMS for a system with these performance goals. The ammonia slip barely falls within the 5-ppm limit as the RMS approaches 20%, leaving no operational margin.

The curves in Fig 3 are based on a new catalyst charge. But what happens to these curves as the catalyst ages and deactivates? The impact of catalyst deactivation is similar to the impact of a higher NH_3/NO_x RMS value. Fig 4 demonstrates how the ammonia-slip margin diminishes as the catalyst deactivates by a nominal 20%. AIG tuning can improve the NH_3/NO_x profile, and recover lost ammonia-slip margin attributed to catalyst deactivation.

Another important consideration is the impact of the NH_3/NO_x distribution on the stack-NO_x profile. If the NH_3/NO_x distribution at the catalyst inlet is stratified, the NO_x profile at the catalyst outlet will be stratified as well (assuming a uniform inlet NO_x profile). If the distance between the SCR catalyst outlet and the stack CEMS probe is short, this stratified NO_x profile may not "mix out" and could adversely impact the CEMS RATA (Relative Accuracy Test Audit) test.

SCR optimization

Improving the NH_3/NO_x distribution by tuning the AIG can help reduce ammonia slip, thereby extending catalyst life. It is important to tune the AIG when a new SCR system is commissioned or when old catalyst is replaced by a new charge, to provide a benchmark for future tests. AIG tuning is also important after changes are made to the gas turbine or duct burners that may impact the SCR inlet NO_x distribution.

Here are several questions you should know the answers to before planning an AIG tuning program:

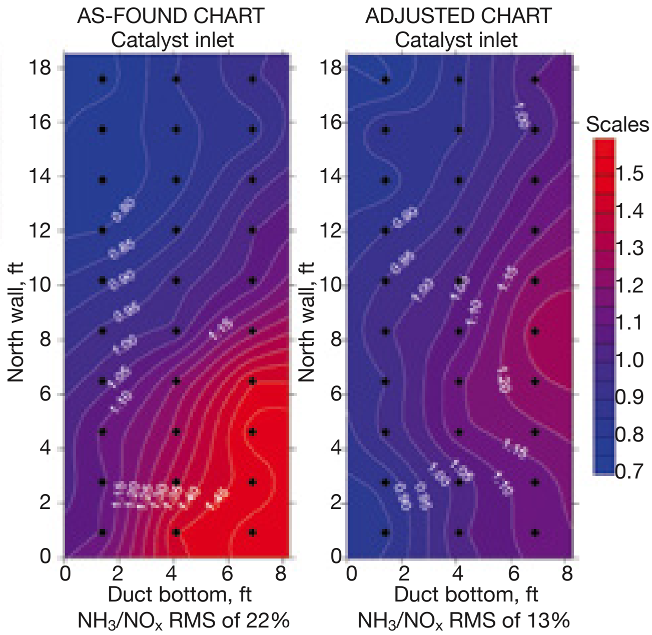
- What are the adjustment options on the AIG? How many vertical adjustment zones? How many horizontal adjustment zones?

  A zone is defined as the injection area covered by one adjustment valve. In many cases, an AIG is designed with only one-dimensional adjustment capability—vertical or horizontal. Best practice: Specify an AIG with two-dimensional adjustability—vertical and horizontal.
- Was the AIG tuned when the SCR system was first commissioned? If not, was a flow model performed during the design stage to evaluate AIG performance?

  This information will provide a valuable benchmark for AIG performance.
- How many access ports are available at the SCR catalyst outlet to measure a grid of points? Are they on both sides of the duct? How do the sample ports align with the AIG tuning zones?

  AIG tuning can be performed with a grid of sample points at the catalyst exit; sample points at the catalyst inlet are not required. AIG tuning is an iterative process, so accurate feedback is critical. The placement and number of measurement points at the catalyst exit depends on the placement and number of AIG adjustment zones.

5. Permanent sample-probe grid can be located outside the duct (left) or inside (right)



6. Before (left)/after (right) data reflect the improvement in NH_3/NO_x distribution made by AIG tuning. In this case, the AIG had only one-dimensional (vertical) adjustment capability, thus horizontal (left to right) gradients could not be eliminated

Ideally, the measurement points will be in the same streamline path as the upstream AIG adjustment zones. This will allow the test engineer to see changes in the catalyst outlet NO_x levels resulting from AIG valve adjustments.

- Is it more cost effective to have a test contractor probe each port from a man lift or to install permanent sample probes for testing purposes?

The former method, also called the "point-by-point" approach, is a slow, labor-intensive process. For example, if a typical test grid has 50 points and it takes nominally five minutes per point to get a measurement, one test will require more than four hours.

But since AIG tuning is an iterative process, multiple tests usually are required. Thus the point-by-point approach may require having the test contractor at the plant for several days. Additionally, on large combined cycles, where the SCR duct is 35 ft wide, or more, the point-by-point approach may not even be feasible because the required sample probe would be too long to handle safely.

The preferred approach is to install a set of permanent sample probes at the catalyst outlet that can be used for tuning purposes throughout the life of the plant. The initial capital cost of installing the probes will be returned in the form of reduced test-contractor costs. The permanent probes and line extensions are typically routed down to grade level, so the contractor does not need a man lift or scaffolding.

An example of a permanent probe grid is shown in Fig 5. With this arrangement, FERCo employs a multipoint analyzer system that is able to perform a 50-point NO_x traverse in less than 45 minutes. Typically, an AIG system can be tuned in less than one day.

- What considerations are necessary to measure the inlet NO_x profile?

The uniformity of the NH_3/NO_x profile depends on the NH_3 distribution as well as on the NO_x distribution at the catalyst inlet. In most situations, it is safe to assume the inlet NO_x profile is reasonably uniform. However, there are some arrangements—such as systems with duct burners—where the inlet NO_x profile can be significantly stratified and must be measured.

This measurement can be made at the catalyst exit probes by turning off the ammonia during the first test (that is, no NO_x reduction through the catalyst). However, turning off the ammonia will impact the hourly NO_x average, and may require a variance from the local regulatory agency.

Fig 6 shows an example of NH_3/NO_x distribution before and after AIG tuning. In this case, the AIG had only one-dimensional (vertical) adjustment capability. The vertical gradients were addressed by valve adjustments, but the horizontal (left-to-right) gradients could not be eliminated. This further illustrates that AIG design has a major impact on the ability to tune the ammonia distribution. Overall, the improvement in the profile was still significant, reducing the RMS from 22% to 13%.

Forecasting catalyst life

Catalyst life forecasting allows the SCR operator to predict and plan for the most cost-effective time to replace catalyst. Keep in mind that if catalyst is replaced too soon, money is lost in the form of wasted catalyst potential. If catalyst is replaced too late, money is lost in the form of a forced outage or fines triggered by high ammonia slip.

Monitoring catalyst activity (or deactivation) is a key component of catalyst life forecasting. Catalyst activity often is reported as a relative activity, which is the ratio of the current activity, K, to the "new" catalyst activity, K_0. When catalyst is purchased, catalyst vendors are able to provide the K/K_0 value at which the catalyst will no longer be effective—that is, end of life.

But it is the operator's responsibility to monitor catalyst deactivation over time and forecast when the catalyst actually will reach end of life. Also, it is the operator's responsibility to retain a new catalyst sample, either with the vendor or at the plant, to serve as a benchmark (K_0) for comparison purposes.

To illustrate how catalyst activity data can be used to forecast catalyst life, a theoretical deactivation curve was developed using FERCo's SCR process simulation model. Fig 7 shows an example of a system designed for 25 ppm SCR inlet NO_x, 2.5 ppm stack NO_x (90% NO_x removal), and an ammonia slip limit of 5 ppm.

For this example, the relative activity (K/K_0) at the end of catalyst life was 0.5. In other words, the 5-ppm ammonia-slip limit was reached when K/K_0 decreased to 0.5. The deactivation rate for this theoretical case was

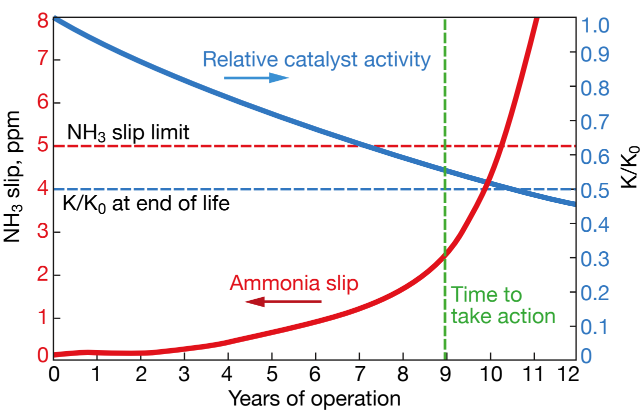
7% per 10,000 hours. At this rate, assuming 18 months were needed to get bids for new catalyst, order the catalyst, and coordinate the installation with a scheduled outage, the time to take action was when the catalyst reached $K/K_0 = 0.55$. Important: This is a theoretical example; actual deactivation rates will vary, depending on the concentration of catalyst poisons in the flue gas.

By measuring actual activity data regularly, you can develop a similar curve for your plant's catalyst as it ages. Your curve then can be used to forecast catalyst life based on the vendor's end-of-life K/K_0 value. Ammonia slip also can be used as an indicator of remaining catalyst life. But as Fig 7 indicates, this is more difficult because slip increases exponentially as the catalyst deactivates.

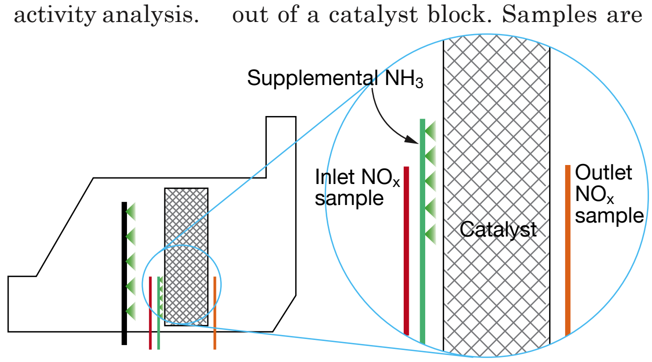
Monitoring catalyst activity

Catalyst activity typically is checked annually by removing a sample during an outage and sending it to a laboratory for an activity analysis. This provides only one activity data point per year, and often requires several weeks before the lab is able to provide the results. For faster and more accurate life forecasting, FERCo has developed an in-situ approach for monitoring catalyst activity called CatalysTrak™ that does not require a unit outage.

To measure K in a laboratory, the test contractor (catalyst vendor or third party) removes a sample of catalyst during an outage and tests it in a lab-scale reactor. The catalyst sample can be a complete test block designed as such by the catalyst vendor, or it can be a "core" sample which is drilled out of a catalyst block. Samples are



7. Plotting of catalyst-activity data over time can be used to forecast end of life based on the K/K_0 value provided by the supplier (ratio of current to new catalyst activity). Ammonia slip also is an indicator of remaining life but this is more difficult because of the exponential increase in slip as the catalyst deactivates



8. In-situ catalyst activity measurement technique, CatalysTrak™, which can be used while the gas turbine is in service without interfering with plant operations or CEMS measurements, enables fast, accurate forecasting of catalyst life usually obtained from the inlet side and outlet side of the catalyst bed. Obtaining multiple samples across the catalyst bed may be warranted if activity stratification is suspected.

The size of the lab reactor and the test conditions vary from vendor to vendor. As a result, it is not possible to compare the measured K value from different vendors. Rather, the relative activity, K/K_0, must be used as the basis of comparison. As mentioned before, it is important to retain a new catalyst sample, either with the vendor or at the plant, to serve as a benchmark for comparison purposes.

In conducting the lab activity test, a specified volume of catalyst is exposed to a known gas flow rate. The gas can be actual or simulated flue gas at a given temperature and inlet NO_x level. Ammonia is then injected at the sample inlet at a high NH_3/NO_x level to provide excess ammonia at the catalyst surface. The NO_x reduction is measured across the catalyst sample, and the activity K is determined from a simple formula based on the NO_x reduction and the flue-gas velocity through the catalyst.

In addition to an activity analysis, chemical and physical analyses can be performed on a catalyst sample to determine the cause of deactivation. For example, the accumulation of catalyst poisons, such as sodium, can be identified in the laboratory. Catalyst surface area, pore size distribution, and pore volume also can be checked.

Primary disadvantages of testing catalyst samples in a lab are the following:

- Samples can be obtained only during an outage.
- Turnaround time for sample analysis typically is several weeks.

For a base-load combined cycle, scheduled outages typically are conducted annually. It is difficult for an operator to develop an accurate catalyst life forecast and replacement plan based on one activity data point per year. Chances are good the operator will lose money by changing out the catalyst either too early or too late.

In-situ measurements. To improve the speed and accuracy of catalyst life forecasting, FERCo developed and patented an in-situ activity measurement method called CatalysTrak. This method can be employed at any time while the gas turbine is operational, and does not interfere with plant operations or CEMS measurements.

Fig 8 provides a description of the CatalysTrak approach. Similar to the laboratory method, NO_x reduction is measured across a small cross section ("test section") of the catalyst bed. A small, supplemental AIG is permanently mounted upstream of the test section to increase the NH_3/NO_x level and provide excess ammonia across the catalyst test section. The activity calculation then is based on the maximum NO_x removal measured across the test section.

The hardware requirements for CatalysTrak are simple, and can be easily installed by plant technicians in a few hours during an outage. This is a one-time installation, which is then good for the life of the plant. The activity tests also are simple, and require only a few hours to complete while the gas turbine is running at normal full-load conditions. A continuous NO_x analyzer is required to perform CatalysTrak tests. Testing can be coordinated using a trusted local stack test contractor along with a FERCo engineer to oversee the tests and calculate the activity results.

The CatalysTrak method is not intended to replace laboratory catalyst activity tests. Rather, it provides operators the ability to obtain more catalyst activity data points for the purpose of forecasting catalyst life. When the catalyst is new, it may only be necessary to measure the activity annually. However, after the catalyst has aged several years, semi-annual or quarterly activity measurements may be needed.

Monitoring ammonia slip. In addition measuring catalyst activity, ammonia slip can be used as an indicator of catalyst deactivation. However, the success of this approach depends on how often ammonia is measured. As catalyst deactivates over time, the corresponding increase in ammonia slip is not linear.

The rate of increase in ammonia slip will jump significantly as the catalyst nears end of life. Therefore, if ammonia slip is only measured annually during the compliance test, it may not provide enough early warning that the catalyst requires replacement.

Example: Fig 7 shows the ammonia slip increased from 0 to 2.5 ppm over the first nine years of operation. However, it took less than two years to go from 2.5 to 5 ppm slip.

In this case, semi-annual (or more often) ammonia measurements would be required to provide adequate warning that catalyst replacement was needed.

Ammonia-slip measurements can be performed by stack test contractors. Alternatively, tunable diode laser (TDL) ammonia analyzers are rugged and sufficiently accurate for this purpose. These continuous analyzers also can be used for system control purposes. Combining stack ammonia slip measurements with CatalysTrak testing on a regular basis will provide invaluable information for catalyst life forecasting.

Catalyst replacement plan

It is important for operators to develop and implement operational procedures based on the foregoing suggestions. This will ensure smooth and cost-effective catalyst replacement events throughout the life of the plant. To summarize, a list of procedures might include the following:

- Obtain from the manufacturer of your catalyst, the relative activity (K/K_0) that represents the end of catalyst life.
- Put in place a methodology for tracking and accurately forecasting catalyst life—for example, laboratory activity, CatalysTrak in-situ, and ammonia-slip measurements. Perform AIG tuning to maximize catalyst life.
- Negotiate new or regenerated catalyst pricing, delivery, storage, and old catalyst disposal well in advance of placing the order.
- Consider if the AIG, catalyst housing, and/or seals require upgrade or modification when the catalyst is replaced.
- Obtain a sample of the new catalyst before it is installed and test for activity. This will be the basis of future K/K_0 tests. CCJ

Labeling equipment for safety, continuity of operation

By Thomas F Armistead, Consulting Editor

We had a retirement party for old Joe last week. When he started at the plant, the smell of fresh paint was still in the air. That was 26 years ago. Joe absolutely knew the main-steam, feedwater, and condensate systems—every valve, every pipe, every piece of equipment. He ate, drank, slept, and lived it. We're going to miss Joe. No one knows those systems the way he did.

If this sounds like the situation at your plant, there's good news and bad news for you. The good news is that you have succeeded in retaining a knowledgeable, caring staff that keeps your plant running without a lot of fuss. The bad news is that when anyone retires, moves to another employer, or dies, that employee's unique knowledge of your plant leaves with him or her. Yes, you can replace the employee, and eventually the replacement may come to know the plant as well as Joe did, but until he or she does, you're flying on a wing and a prayer—hoping that the employee's learning curve with the plant doesn't end in a mishap.

If you have a guy like Joe at your plant, and he hasn't yet retired, count your blessings. But if your plant is like many, your workforce may have a number of highly skilled nomads, just watching for a better opportunity with higher pay at another plant. Even with Joe on your staff, your luck can't hold forever. During the recent economic downturn, a lot of people postponed retirement until their IRAs can recover some value. As they do, watch your exits.

"Through the recession, people have stepped back from retirement plans," said Anita Decker, chief operating officer at Bonneville Power Administration. As the economy improves, she expects a lot of retirements—"a big bubble" of retirement demand has built up. Joe—and the other baby boomers on your staff—may just be waiting for the right time.

A good asset-identification or plant-labeling program won't keep Joe on staff, but it can go a long way toward keeping his plant knowledge in-house and available to your staff. That knowledge could be the key to reducing the duration of an unplanned forced outage—or something much worse—in your plant.

Labeling program approaches

Many plant managers may see asset identification as a good way to train new employees and keep operators occupied during slow times while improving equipment labeling and line tracing, and they will launch the program mainly for those reasons. Gulf Power Co's 970-MW, four-unit James F Crist Generating Plant, Pensacola, Fla, had no labeling system when it started adding small tags made in-house around 1997, said Jay Weston, Plant Crist's asset manager.

"Using plant personnel, we didn't make much progress," he said. Later, the addition of air-pollution-control equipment created an opportunity.

1. Labeling: An investment in your plant

OK, granted labeling's a "good thing." But what's the payoff? "Benefits of labeling are hard to quantify in normal return-on-investment terms," said Marking Services' Jason Harry. "However, the benefits can be huge when you consider prevention of accidents and injuries and avoiding unscheduled plant outages due to errors." Knowing the expected benefits of an asset identification project will help management define the tasks and resources needed to achieve the goal. The purpose of properly installed plant labeling is to support the facility operation by providing critical information to plant personnel in a standardized and consistent manner.

MSI lists the following as some of the benefits of labeling:

- Hazard reduction and prevention of human errors: A comprehensive labeling program contributes to the effective functioning of process operations, and limits the potential for downtime or injuries attributed to O&M errors.
- Training of plant personnel: As the plant workforce turns over, training of replacement personnel will be critical to the safe and efficient operation of the plant. A comprehensive and effective labeling program facilitates the training of new personnel by bringing critical information to the field where it is needed for operating and safety procedure application, emergency response, and day-to-day plant maintenance.
- Enhanced effectiveness and creation of in-plant procedures: Creation of new procedures is enhanced because the assets are identified and their locations within the plant are verified through accurate drawings and physical identification. Accurate and thorough labeling of critical plant components helps ensure that personnel properly execute standard operating and safety procedures by visual confirmation.
- Uniformity of labeling nomenclature: A standardized labeling program contributes to the flow of information and feedback among all departments—including operations, maintenance, environmental health and safety, administration, purchasing, and management.

1. Effective tags clearly identify equipment (above)

2. Ink marking on piping, an expedient for plant staff, often becomes the permanent label (right)

3. Good label placement requires attention to detail to ensure visibility

"With construction of the scrubber and SCR, we had the money and drawings to label at the end of each project," Weston said. "Plant loved it, and now we are labeling another project with plans to start moving to existing plant equipment."

To Weston, labeling is more than a good idea; it's good business (Sidebar 1). "Safety is one of the primary drivers to me," he said. "It shortens time in the field locating and identifying equipment. Tagging insures accuracy. Also, we use tag identification for writing work orders and to give the person working on the equipment verification of what is isolated (Fig 1)." And not everyone working in the plant is familiar with the facilities. With labels on equipment, piping, and valves, plant management can give directions to contractors with confidence that the labels will help orient them.

Weston no longer does labeling work with plant staff, though. In 2009, he contracted with a company that specializes in creating and installing asset-identification systems, Marking Services Inc (MSI), Milwaukee. "We wanted someone who could furnish the labels and actually install them. That was part of our problem trying to install labels and tags with plant personnel: We couldn't keep dedicated employees long enough to make any real progress," he said.

Plant Crist's difficulty is not unusual, said MSI's Jason Harry. "Probably not very many [labeling projects] ever reach the level of completeness the plant intended. This is why MSI is in business," he said. "The success of labeling programs begins and ends with how much value the management places on it. If management values labeling, they will support it financially. If not, you get operators writing on pipes with Magic Markers (Fig 2)." Some drawbacks to doing the work in-house, he said, include use of improper materials, labels lacking necessary information, and poor label placement (Fig 3). In addition, as Weston found, the job may never get done, or it may be done on premium time—nights and weekends.

In-house labeling has worked for nonutility generator Tenaska Inc, though. At the 270-MW Tenaska Ferndale Cogeneration Station, Ferndale, Wash, two GE Frame 7EA gas turbines with supplementary-fired heat recovery steam generators and an extraction/condensing steam turbine provide hydro-firming power to Puget Sound Energy.

The plant went commercial in 1994 with only the labeling required by regulations, said Plant Manager Tim Miller. The "above-and-beyond" labeling was done by plant staff using a vinyl label maker. There is no plant standard for labels. The labeling is governed by a company philosophy of best practices, which do produce results: The plant is an OSHA STAR work site, and has not had a lost-time incident since it began operation, Miller said.

Tenaska is aware of the value of good labeling. "We consider it essential for prudent operation, and it helps support all our major metrics—safety, efficiency, and reliability for our customer," Miller said. Good labeling is important for safety because it ensures proper identification of systems, including whether systems are out of service and can be safely worked on, he added.

No respect

Comprehensive plant labeling is rare, in the experience of Charles Henley, chief piping engineer for powerplant engineer and constructor Black & Veatch, Overland Park, Kans. "Less than half of the powerplants get labeled," he said. "If the client doesn't specifically require something, we don't do it." That's a common practice in industry, where labeling is "an afterthought," he said, largely dependent on the type of client. An investor-owned utility company is probably more likely than an independent power producer to label its plants. Labeling also is "more regional than it is anything else," he said, citing a plant in Alberta, Canada, where the owner wanted ASME 13.1 labels on everything. "They were very particular."

Labeling gets little respect from

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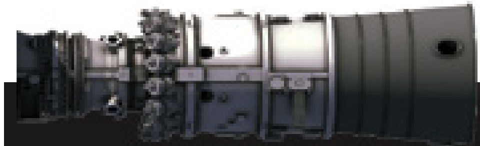
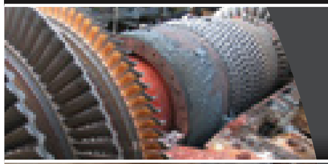
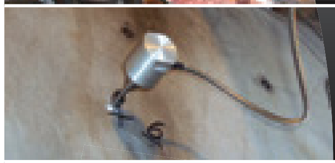
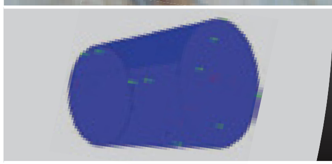
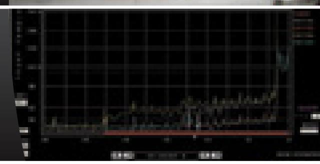


ACTMS™ On-line Stator Vane Crack Detection		AMS™ HRSG Leak Detection
 • Cracking/liberating vane through turbine • Stationary airfoil cracking • Rubbing, loosening and blade clash • $7 to 10 million per incident	**PROBLEM**	• Tube stub weld leaks at the SH & RH headers • Tube leaks at the SH and RH Drains • Inability to locate area of the leak 
 • Non-intrusive sensors • After-market install • Complete forward compressor coverage	**IN SERVICE**	• Non-intrusive sensors • After-market install • 24-7 real time monitoring • Total HRSG coverage or in areas of most concern 
 • Defect source location • Graphical displays • Local and network alarming	**REAL TIME**	• Trend severity and progression of leak • Locate area of leak before unit removed from service • Local and network alarming 
 • On-line detection of vane cracking • Insight to unknown condition • Optimize remaining life • Early warning to prevent failure	**RESULTS**	• On-line tube leak detection • Early warning to prevent failure • Manage market exposure and risk • Tube leak repair during planned outage or period of low demand 

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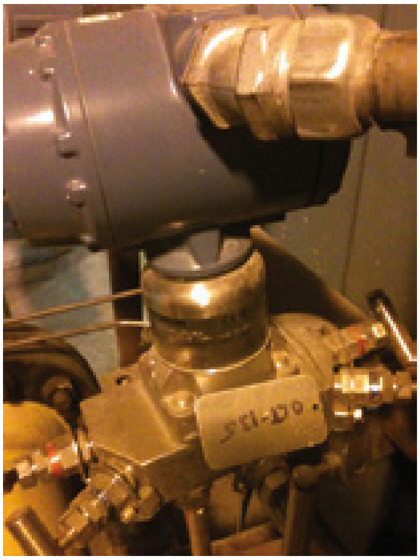
Designation of Colors (ASME A13.1-2007)	
Classification	**Letter/Background Color**
Fire Quenching Fluids	White/Red
Toxic and Corrosive Fluids	Black/Orange
Flammable Fluids	Black/Yellow
Combustible Fluids	White/Brown
Potable, Cooling, Boiler Feed, and Other Water	White/Green
Compressed Air	White/Blue
To be defined by the user	White/Purple
To be defined by the user	Black/White
To be defined by the user	White/Gray
To be defined by the user	White/Black

4. ASME A13.1 is the national standard for pipe labeling (left}

5. Exposure to elements, especially direct sunlight, is hard on labels (above)



6. Without plant specifications, labels may vary greatly and have inadequate information and non-durable inscriptions (left)

7. Installing labels requires access to some hard-to-reach parts of the plant (above)

professional standards committees. ASME 13.1 (Fig 4) is the required standard for pipe labeling, but no sources cited any other national standards for powerplant labeling, only a handful of state standards. "There's not really a requirement to put identification on piping systems," Henley said. "We do it based on what our customer's requirements are." ANSI V 535.1 is a safety color code, but it's not required, as ASME 13.1 is.

Henley guessed that only 10% to 20% of owners require labeling in their plants for piping systems that are not flammable, hazardous, or combustible, but the majority of the owners want tags or some other type of labeling on valves, equipment, and anything else an operator has to operate.

"Every plant has some kind of labeling but the thoroughness varies greatly," said MSI's Harry. "Older plants tend to be labeled with materials that were state-of-the-art at the time—stencils, brass, stickers, and engraved plastic. These materials don't hold up well over time, especially if they are exposed to the elements (Fig 5). It is common to have a wide variety of labeling materials in the plant (Fig 6). This happens because no labeling specification is established for the plant."

When developing specifications for your plant's labeling system, consider inclusion of barcodes on all equipment labels. Scanning barcodes on rounds is one way to verify all equipment that needs to be check is actually checked. Further, barcodes enable O&M personnel to link directly to information needed to operate and maintain a given component while in the field.

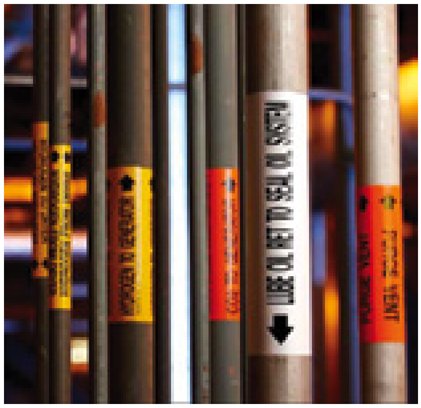
Sources generally reported that they would expect the engineering-procurement-construction (EPC) contractor to do the labeling, but it normally happens only if the owner requires it. If an owner puts labeling in a contract, Black & Veatch will do it or subcontract it to an insulation or painting contractor, either of which can easily do it while the scaffolding is in place for their work, Henley said (Fig 7). The problem with that approach is that, without a plant standard, labels furnished by different contractors will lack uniformity, hampering communication, said Harry.

From all accounts, it appears that Marking Services is the only contractor that specializes in both furnishing and installing asset identification, and Henley did sub the Alberta plant's labeling to MSI. But labeling is not high on an EPC's priority list; it will be picked up later if at all, Henley said. In his opinion, labeling is best done by the owner's staff because they know the plant. "If people aren't familiar with an activity, stuff gets mismarked," he said.

Sold on labeling

New Harquahala Generating Station (NHGS) is a 1092-MW plant with three Siemens 501G turbines in 1 × 1 combined-cycle configurations. An investors' group, MACH Gen, Athens, NY, purchased NHGS at 60% completion and finished its construction in 2004. The plant is operated by NAES Corp, Issaquah, Wash.

Generating stations typically label equipment, piping, tooling, etc, as



8. Label adhesion is prone to failure under extreme plant conditions (above)

9. Colors quickly indicate pipe contents (right)

10. Wrap-around labels ensure identification from all sides

a means to improve safety through proper system identification. In addition, labeling enhances the training of station personnel, and plant reliability is improved by reducing misinterpretations of system components and associated piping.

"There was no equipment or tooling labeling in the plant when we started work, so we started down the path to do it in-house with our own team because we knew lack of labeling would be a systemic blind spot for us," said Dean Motl, NHGS plant manager. "We ended up deciding this effort would be a very difficult, arduous process." Ensuring standardization, identifying the locations for labels, making the

Motl

labels, and making station staff available for the work were forecast to be too time-consuming to be overcome while attending to normal operations and maintenance duties. "Fortunately, we realized that we could not effectively complete the work in-house."

Local environmental conditions further complicated the task, as New Harquahala is located in a region of high heat and intense sunshine. The station needed labels made from materials resistant to chemicals and heat (Fig 8). Searching for possible solutions at a tradeshow, Motl found MSI and was impressed with the company's product. MSI, which specializes in UL/CSA labels, warning/caution labels, nameplates, graphic overlays, membrane switches, bar code labels, and insulators, was ultimately awarded a services contract for the station's labeling needs.

MSI took the plant's piping and instrumentation diagrams and line drawings, and proposed a list of labels, Motl said. MSI and plant staff met to confirm the accuracy and completeness of the list and to maximize efficiency of effort. When confirmation was complete, MSI printed out marking stickers and walked down the plant to place the stickers. That was followed by walk-downs to verify accuracy and approve placement. Only at that point were labels made. Label hanging took about a month, and did not interfere with plant operations or production.

The consistent labeling improved the plant's aesthetics and provided a

2. How to develop a labeling program, step-by-step

A quality plant-labeling program is guided by the following elements:

- A labeling standard.
- Defined responsibility for labeling.
- Ongoing management of change process that takes labeling into account.
- Ongoing maintenance of plant drawings.
- Validated plant drawings (P&IDs).
- Defined performance requirements for the labeling materials.

Execution of the program requires the following information:

1. Defined standard
   Who is responsible for labeling, initial and on-going?
   What will be labeled?
   What information will be on the labels?
   What material will be used to label?
   Where will labels be located?
   Other specifications such as size, color codes, etc.
2. Determine the source of information for labels
   Up-to-date and validated P&IDs.
   Equipment lists.
   Asset database.
   How will you generate missing information?
   Nomenclature to be used.
3. Determine the project timeline.
4. Validate the information.
5. Engineer and develop a bill of materials.
   Line number and "From/To" on pipe labels.
   Electrical feeds.
   Determine attachment methods.
6. Product
   Make in-house or purchase?
   Performance.
   Lead time/delivery.
   Packaging for installation.
   Process for new or replacement labels.
7. Installation
   Train on how to install product.
   Location parameters.
   Work from heights.
   Labeling process versus labeling area.

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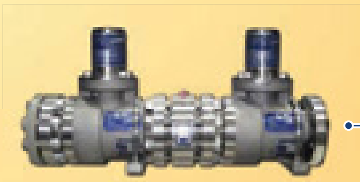

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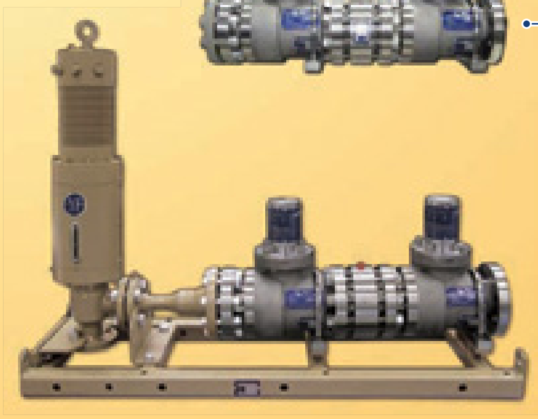

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11, 12. The tag will stay with the foundation, but what does it say? (left) The more information, the better (right)

sense of pride and professionalism for the station staff, and when visited by regulatory and governing agency personnel, Motl said. Whenever the plant updates its equipment, he added, it sends a list of changes to MSI and new labels are prepared to match the existing scheme "to ensure consistency with the plant's best-in-class initiatives and alignment with NHGS ownership and NAES core values."

Brian Paetzold was in the Navy and is now the assistant director for three NV Energy powerplants near Las Vegas: Chuck Lenzie, Harry Allen, and Silverhawk Generating Stations. "The Navy is the de facto standard for labeling," he said, and he likes to apply his Navy training to labeling his plants.


Paetzold

A good labeling system uses colors to identify components that have similar functions, he said (Fig 9). It should use a suitable font, visible at a distance, and arrows showing process flow so operators know at a glance what the flow is. The labels and signs should be visible from multiple angles (Fig 10). Labels on a piece of equipment should be affixed to the foundation so they will remain in place if the original equipment is replaced (Fig 11).

Black & Veatch's Henley also likes to see spring-formed labels wrapped around a pipe because they won't peel off when heated, as an adhesive label can. Letter size should be proportional to the pipe size, with high contrast between the colors for the lettering and the background. Flow arrows also are important. On equipment labels, he likes to see the system name, the purpose of the valve, and the valve tag ID number, with stainless steel wire holding the label on the valve or equipment (Fig 12).

NV Energy bought the partially completed 1102-MW, 4 × 2 combined-cycle Chuck Lenzie Generating Station in 2004 and completed it in 2006. Harry Allen Generating Station last year completed the addition of a 484-MW CC system to what had been a pair of 72-MW combustion turbines operating in simple cycle. Paetzold contracted with MSI to provide labels for both plants. NV Energy doesn't have a standard for labeling, so he relied on MSI's system. "Lenzie has been identified as a strong leader in labeling and a model for the rest of the fleet," he said.

Operators at these plants are showing other sites in NV Energy's system how their labeling works. To illustrate the benefits of good labeling, Paetzold points to Lenzie's air-cooled condensers. A technician inside a cell can think he's in a different cell from the one where he actually is, and thus may do maintenance on the wrong cell. Signage clearly visible from inside the cell in two directions tells the technician the cell's identity.

"One of the important things about labeling is the safety aspect of it," Paetzold said. Technicians know exactly which piece of equipment they are working on, and quickly see if they are in the wrong place. He has heard of instances when labels caused people to halt work when they realized they were in the wrong location.

Lenzie's labels have been in place for about four years and have faded in the direct sunlight, so the plant is relabeling now. NV Energy doesn't have a protocol for label maintenance, but it does a health and safety audit every two years, and can include a label walk-down to identify labels needing replacement or updating.

Joe, of course, never needed the labels anyway; he knew the plant. But Joe is fly-fishing in Patagonia now, and he's not coming back. Who has taken his place? And what does his replacement know about your plant's systems? CCJ


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How to eliminate thermal losses, identify equipment deficiencies

By James Koch, Powerplant Performance Specialist

In the early 1980s, performance monitoring gained emphasis in response to skyrocketing fuel costs following the 1970's oil crises. At one of the first major heat-rate conferences, a presentation by an expert on ASME Performance Test Codes stressed the value of the PTCs this way: "We need accurate incremental heat rate for dispatch, daily monitoring to optimize operator-controllable losses, trending for prudent maintenance scheduling, and, of course, reports—we all need to write reports."

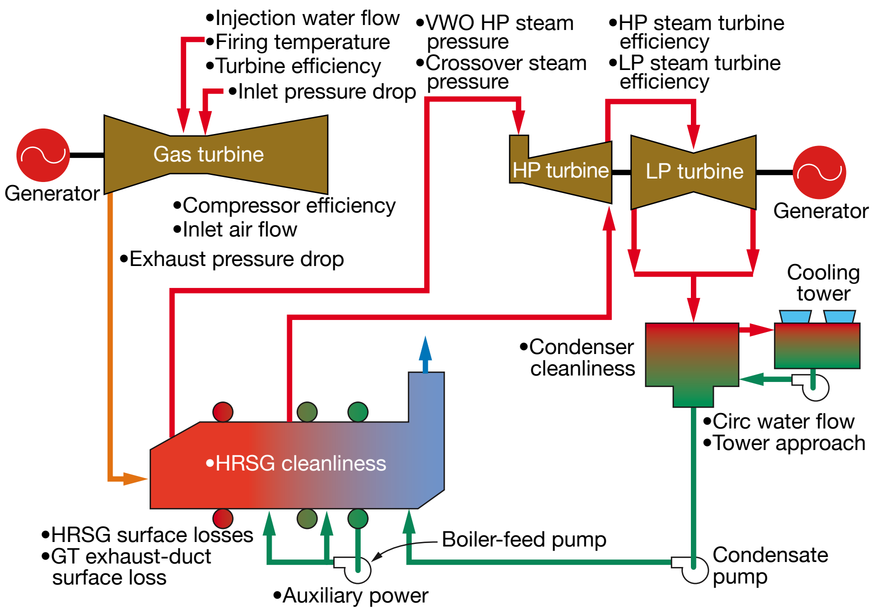
Perhaps that was the case 30 years ago, but today's plant and asset managers don't want *reports,* they want *solutions*. And not just *an* answer, but the *right* answer. They need to know that the numbers they're shown, the recommendations presented, and the suggested course of action to correct performance issues will be justified economically.

Think of it this way: You take your car to a mechanic and tell him it doesn't seem to be running well. You ask him to keep the car for a few ways and check back when he knows what the problem is. Your expectation of the mechanic's evaluation might be something like the following:

- You're right, sir, the mileage is down about 5 mpg.
- You need a tune-up to correct the issue.
- It will cost about $150.
- With average use, the repair will pay for itself in about four months.

Plant management needs the same type of service:

- Is my plant not performing as it should be?
- If not, why not?
- What exactly is the problem?
- What is the deficiency costing me in lost revenue and/or excess fuel?
- What work is required to correct the problem?
- How much will the repairs cost?
- Most importantly: Are the repairs worth making?



1. Combined-cycle parameters, when calculated through testing or monitoring, point to plant components requiring attention to restore expected performance

Performance impacts

Like the way the various engine components affect car mileage, the various components of a combined cycle affect overall plant performance. Furthermore, the performance of each component can be characterized by one or more parameters related to the mechanical or thermodynamic performance of that component.

Fig 1 shows key performance parameters schematically. For example, gas-turbine (GT) performance can be assessed by looking individually at (1) inlet air flow, (2) compressor section efficiency, (3) turbine section efficiency, (4) inlet and exhaust pressure losses, and (5) parameters that may be "operator set-point controllable"—such as the reference exhaust-temperature curve (aka "firing" curve), inlet-guide-vane (IGV) position, and water or steam injection flows.

When the loss in GT output is attributed to changes in these parameters, and a megawatt loss is assigned to the lower-than-expected value (or higher in the case of some parameters, such as pressure drop), then plant management has the information needed to address the same questions as the car owner above, namely:

- What is the problem?
- Is it worth fixing?

GT performance parameters, together with balance-of-plant (BOP) parameters such as steam-turbine (ST) efficiency and condenser cleanliness, can be determined through testing or monitoring, and will point to those components requiring attention to

restore overall plant performance. Determining and trending performance indicators, correlating changes in the parameters to changes in unit performance, and understanding how instrument uncertainty affects uncertainty in the perceived (that is, calculated) values of these parameters, are at the very root of analyzing plant performance.

Examples 1 and 2 describe two common problems at combined-cycle plants. In each case, common-sense thinking and basic instrumentation were able to identify the problem, indicate a solution, and show that the proposed fix was cost-justified. These two examples are, of course, for demonstration purposes; it isn't always this easy.

But, while some problems are more complicated, require more pieces of field data, and more detailed analysis, there are also many issues that can be identified with some basic knowledge of plant operation, a few measurements, and some arithmetic.

Getting started. The challenge of today's plant owners and operators is not simply monitoring and analyzing performance, but doing so in a time of limited budgets, reduced staffing levels, and combined-cycle technologies that are becoming increasingly complex. The last makes accurate analysis more difficult. Critical, too, is that the performance monitoring and analysis effort provide owner/operators a compelling value proposition.

OEMs once shared virtually all information regarding performance curves; you may recall the "thermal kit" for steamers. Try finding the equivalent of that kit for a gas turbine. Usually all that is available is a set of correction curves from the acceptance test. But these aren't necessarily optimal for performance monitoring—because they were prepared with a commercial purpose in mind. Furthermore, it is not unusual to find inaccuracies in such correction curves.

Common sense rules. Often a plant wants to get started with performance monitoring, but management drags its feet in moving forward because the cost of running a full test in accordance with the ASME PTCs. They recall the manpower, high cost, and complexities of conducting their own contract acceptance tests. Unfortunately, managers too often make a connection between running a Code-level contract test and doing simple, routine trending—and they stop dead in their tracks.

When the purpose of a test is to demonstrate a contract-level of performance, and there are significant damages or bonuses tied into tenths (or hundredths) of a percentage point in the test results, it behooves both parties to run a highly accurate test. It's likely that each tenth of a percentage point in the results could cost one party or the other many thousands of dollars. This is where high-accuracy, high-cost instrumentation and procedures can pay for themselves by reducing test uncertainty.

But, if the plant is running a simple test for routine monitoring, or trending performance for its own internal purposes, the results do not need to be anywhere near the Code level of accuracy. This is not to say that the monitoring can be done sloppily, or with instruments that are known to be out of calibration or improperly installed.

Rather, the instrumentation and process needs to be of sufficient accuracy (and repeatability) so the conclusions drawn, and the actions taken, are correct. This level of accuracy is significantly less expensive to achieve than PTC-level testing. If fact, almost any plant built since about 1970 should have instrumentation and archival capability to immediately start a successful monitoring program.

As noted earlier, each component in the cycle can be characterized by one or more performance parameters that attest to its efficiency, heat-transfer capability, capacity, cleanliness, etc. But, before jumping into performance assessment with both feet, there are some preliminary steps to take that are well within the reach of most plants.

Accounting. The goal for any performance monitoring program is to improve the facility's profitability. Two items that can impact the bottom line more than any other are the accuracy of the largest cost stream (fuel expense) and the main revenue stream (power metering). It's surprising how many facilities don't perform regular fuel and power-production accounting, using their own in-house instrumentation against over-the-fence revenue meters. And when they do perform these checks, it's surprising how often the results disagree—sometimes significantly.

A simple check can be done using PI or a similar data archival system. For every hour of the month, tally all of the site's gas flow meters, and compare that result with what the revenue meter reports. It's not unusual for a plant to find that the gas revenue meter disagrees with the onsite fuel flow meters by as much as 2%. If there is a disagreement it's not too hard to find which meter is the one out of calibration by looking for how the difference varies depending on with which GT, or duct burner, is in service or offline.

A simple fuel accounting is presented in Example 3. One plant that has been comparing data from its fuel-flow meters against the gas company's meter for the last eight years or so reported it took a few months to establish its program. First step: Identify and calibrate plant meters providing questionable data. Next, confirm that procedures correcting for temperature, pressure, and gas composition are accurate. Final step: Establish a schedule for verifying flow meter calibration.

Since that time, plant and supplier

Example 1: Is a compressor wash beneficial?

Compressor efficiency and calculated air flow indicate that an offline compressor wash is needed. The outage cost (lost revenue) for this 350-MW 1 x 1 combined cycle would be $20,000; cleaning is an additional $2000.

Washing should improve compressor efficiency by 2 percentage points, based on historical data; plus, air flow should increase by 2%. Combined, these benefits should produce a 12-MW increase in combined-cycle output.

For an average spread of $10/MWh, plant revenue should increase by about $2000/day, giving a simple payback of about a week and a half. Conclusion: Schedule the wash.

Example 2: Is it time to clean HRSG heat-transfer surfaces?

GT exhaust backpressure has increased by 3 in. H_2O for this 350-MW, 1 × 1 combined cycle since its heat-recovery steam generator's finned heat-transfer sections were cleaned two years ago. Recovery of the 3-in.-H_2O penalty would increase GT output by about 2 MW. Plus, steam-turbine output would increase by about 1 MW because of the higher steam flow associated with better heat transfer.

Cleaning a unit of this size costs about $100,000 and requires a five-day outage. A simple payback of about six months would be expected. However, this estimate only includes the cost of cleaning; the cost of a dedicated outage cannot be recovered. Solution: Write HRSG tube cleaning into the outage plan for the next opportunity when there is a five-day window.

data have been within 1% of each other—consistently. This result is valuable in two ways. First, the plant knows each month that its fuel bills are correct. Equally important is that for performance calculations requiring fuel flow, the uncertainty is reduced because there is high confidence in measured fuel flow.

The same type of accounting check can be done with generator output, comparing the sum of the GT and ST generators, minus auxiliary power, against the revenue megawatt-hour meter. Like the fuel-meter check, this gives confidence in revenue metering and also ensures the accuracy of data for use in more exacting calculations when they are required.

Corrected output. In combined-cycle monitoring, it is most important to determine the output (overall plant, GT, and ST) corrected for ambient conditions. As most plant personnel are aware, gas-turbine output varies indirectly with ambient temperature.

Reason is that the power generated by a GT is proportional to the mass flow of air through the machine; a constant-speed GT takes in air at constant volume flow. Thus, when colder, the air is more dense (that is, there is more mass per unit of volume) and more power is produced. This relationship between temperature and output also holds for the overall combined-cycle plant and generally for the ST. Examples of correction curves are in Fig 2; a simple correction calculation is presented in Example 4.

It is very important to remember the difference between ambient air temperature and the compressor inlet temperature. If evaporative coolers or inlet chillers are in service, the latter is colder than ambient air and the correction on a warm day will be less than if ambient temperature were used. If your plant has no correction curve for output as a function of GT inlet temperature, a curve for a similar GT model can be substituted temporarily for informal monitoring until the actual curve can be obtained or derived.

Keep in mind that GT and overall combined-cycle output also vary with barometric pressure. This correction often is overlooked because barometric pressure doesn't change much with ambient temperature. Even though there usually is only a small (less than about 2%) variation in barometric pressure day-to-day, its impact on performance may be greater than that of inlet temperature and cannot be ignored. Example: A 2% change in barometric pressure will introduce a 2% error in corrected GT and plant output—a direct one-for-one percentage impact.

If an accurate measurement of barometric pressure at the plant isn't available, or if you want to verify the DCS reading for barometric pressure, a nearby major airport is a reliable source. Weather information can be found at the NOAA web site. If the day is calm, and the airport nearby, there is no reason that the barometric pressure measured at the airport isn't the same as that at the plant. But, be sure to compensate for plant elevation, since airport readings are corrected to sea level for aviation, and are not the local barometric pressure. Example 5 illustrates how to do this.

Example 3: Simple fuel accounting

GT1 fuel flow, lb/sec	28.55
GT2 fuel flow, lb/sec	28.39
Total fuel flow, lb/sec	56.94
Total fuel flow, lb/hr	205,000
LHV of gas, Btu/lb	20,600
Total heat input (LHV), million Btu/hr	4223
Total heat input (HHV), million Btu/hr*	4683
Gas company fuel flow, 1000 scf/hr	4602
HHV of gas, Btu/scf	1024
Gas company heat input, million Btu/hr	4732
Agreement, million Btu/hr	49 (1%)

*Multiply LHV by 1.109 to get HHV

Example 4: Correcting GT output, heat rate for ambient conditions

GT capacity (as tested), MW	215
GT heat rate (as tested), Btu/kWh	9350
Ambient test conditions, F/psia	78/14.8
Reference conditions, F/psia	60/14.7
Corrections, capacity	
Temperature	1.033
Barometric	0.993
Correction, heat rate	
Temperature	0.995
Corrected results	
Capacity, MW (215 × 1.033 × 1.007)	223.7
Heat rate, Btu/kWh (9350 × 0.995)	9303

Example 5: Determining barometric pressure at the plant

Airport barometric pressure, in. Hg (0-ft elevation)	29.62
Correction for plant (500-ft elevation), in. Hg.	-0.50
Plant barometric pressure, in. Hg	29.12
Plant barometric pressure, psia*	14.30

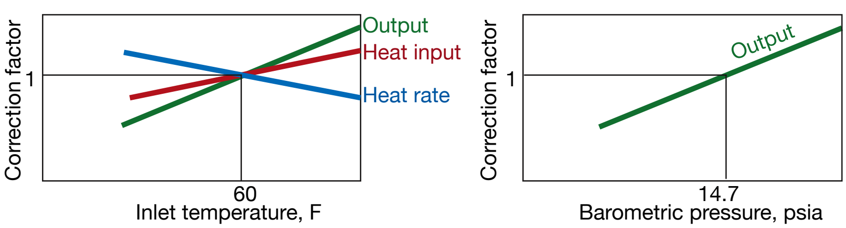
*Multiply in. Hg by 0.4912 to get psia, the units used in monitoring

Compiling actionable information

Once you have corrected GT, ST, and plant outputs to say 60F, 60% relative humidity, and 1.7-psia barometric pressure, compare the data to one or more reference points—for example, ISO, the OEM's original design, the guarantee point, acceptance-test results, or the performance since returning from the last major.

This should be done in an accounting manner, as shown in the table on p 40. After correcting as-found plant performance to the reference condition, a comparison against the benchmark performance will point to where the deficiencies are. From the data presented here, it looks as if GT2 may have a problem. Further analysis by an in-house specialist probably would identify the specific issue; so might a performance package. Absent those capabilities, basic arithmetic and thought can direct the plant toward a solution.

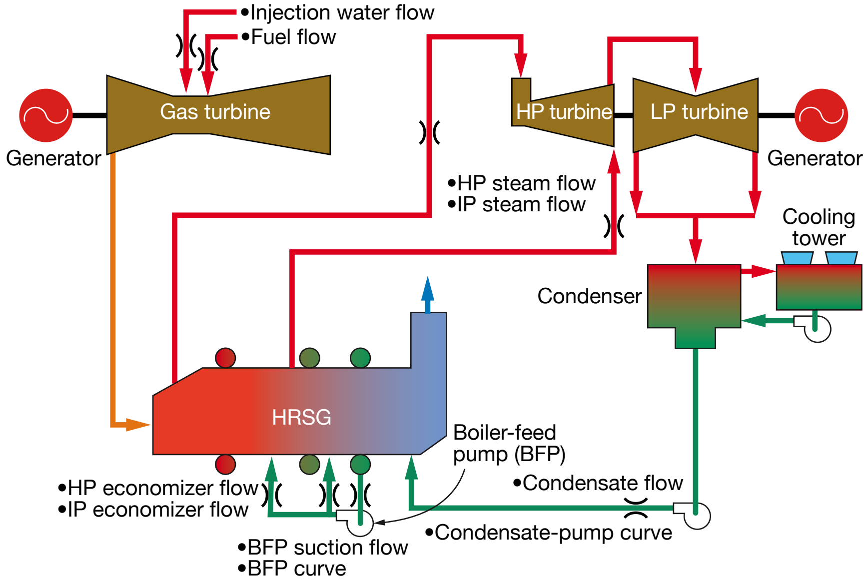
Simple-cycle GT. In addition to correcting the output of a simple-cycle GT, it's important to both correct heat rate and to monitor it on an ongoing basis. Recall that heat rate is the number of British Thermal Units of fuel burned divided by electrical output.



2. Correction curves for air inlet temperature (left) and barometric pressure (right) illustrate how power production varies with ambient conditions. Similar correction curves also are required for humidity, inlet and exhaust pressure

	GT output same	GT output decreased
GT heat rate same	No change	Air-flow problem
GT heat rate increased	Not possible	Efficiency problem

3. Diagnosing performance issues



4. Accurate flow measurement is critical to performance analysis. Diagram indicates where flow meters should be installed in your plant—at a minimum (right)

Reasoning that the amount of fuel used is roughly proportional to air flow, this parameter can be used as an informal diagnostic to determine if output is not meeting expectations because of low air flow or low internal mechanical efficiency.

Fig 3 illustrates that if heat rate on a given day is the same as it was during an earlier period, but the output is lower, both fuel flow and electric production are down proportionally. It stands to reason that air flow is down as well. Furthermore, since heat rate essentially is the reciprocal of efficiency, if efficiency is the same and output is down, then the internal efficiencies of the compressor and turbine sections are not the problem. This scenario usually indicates low air flow.

But if heat rate is up and output down by roughly the same percentage, then fuel flow is the same as before and air flow most likely is the same as well. In this case, the problem is related to the internal efficiencies of the turbine and/or compressor sections.

As the illustration shows, it's not possible that the power can be the same but heat rate higher; this would imply that the fuel flow, and hence air flow, have increased. Like output and section efficiency, air flow doesn't get better by itself. If the calculations for this result are confirmed, then a rigorous check of instrument calibration is strongly recommended.

While more detailed calculations will quantify air flow, compressor efficiency, and turbine efficiency, the reasoning in Fig 3 is a good start for diagnosing engine performance in the absence of more powerful calculations.

The Rankine cycle

In doing the thermal accounting, the next step in the analysis leads to the steam-cycle portion of the combined cycle. If ST output is below expectations, the reason most probably is one of the following:

- HRSG is not effectively making steam from the available heat in the GT exhaust, resulting in low steam flow.
- The expected amount of steam is being generated, but turbine output is lower than expected.
- There is a loss of steam in the cycle. For example, steam may be bypassing sections of the turbine, or perhaps it is being dumped directly to the condenser.
- The cooling system is unable to achieve the design vacuum. Perhaps circulating-water flow is low or the cooling-water inlet temperature is high.

If you have experience with conventional fossil-fired steam units, recall that flow measurement is all-important for analyzing steam-cycle performance. Most combined cycles, like coal-fired plants, are equipped with similar instrumentation to measure flows of condensate, feedwater, and steam (Fig 4).

In addition to direct measurements of steam and water flows, there also are indirect flow measurements that offer a valuable check. To illustrate: If fuel flow and GT generation are reliable, as discussed above, it is possible to calculate a reliable value for exhaust-gas mass flow. This result can be used together with stack temperature to determine the total amount of heat transferred in the HRSG. The result either will confirm the measurements of water- and steam-side flows or alert the plant that these meters may be in error and in need of calibration.

Another way to measure flow indirectly: Use boiler-feed and condensate pump curves and measured discharge head. While not acceptable as a primary flow measurement for contract testing, these parameters provide another check on condensate and feedwater flows for routine monitoring.

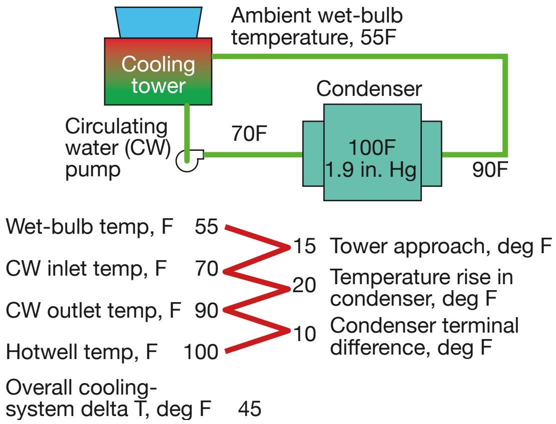
Flow versus pressure. One sometimes overlooks performance-loss results when steam is bypassed to the wrong place. Such losses traditionally are found by survey, using an infrared heat gun. But this can be time-consuming and usually is done only periodically. A way to narrow down the potential places where steam is being lost is to use stage pressures as a flow meter to find isolation losses.

When learning how to perform a heat balance, one of the first principles taught is that stage pressure varies as flow to the following stage. With this simple rule, you can use steam pressure (or in the case of the GT, air pressure) as a flow meter. More specifically, a lower-than-expected stage pressure indicates that flow through the following stage will be lower as well. The takeaway: There may be an isolation loss of steam just before that pressure measurement.

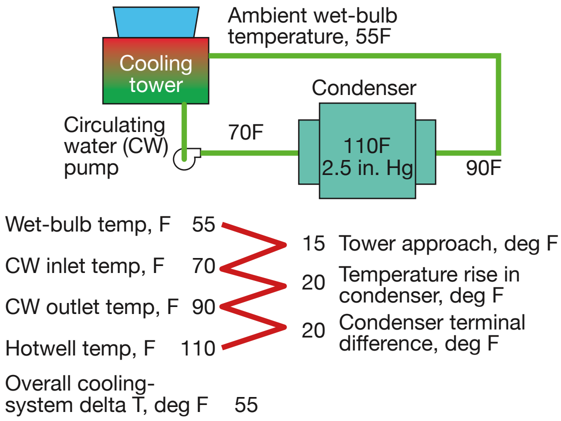
This "trick" has been used with great success in both combined cycles and conventional steam systems for years. Plants can use lower-than-expected upstream stage pressures to identify valves to the condenser that are leaking. For example, if reheat pressure is down, say 5%, it follows that there may be a 5% loss of flow to a condenser drain.

For a combined cycle, "finds" in the steam cycle are especially valuable because they represent "free energy." Keep in mind that correcting a performance loss in the ST cycle does not require additional fuel to the GT as would, for example, the need to increase air flow. Thus, the extra ST output after the problem is corrected is pure profit for the facility. Revenue produced at no cost is added to the bottom line.

Cooling-system delta Ts. The



5. Expected design performance for the main cooling system reflects an overall cooling-system delta T of 45 deg F



6. Condenser heat-transfer problem is suspected when comparing data here to those in Fig 5 for the base case

second best "trick" in the book is to use some simple temperature readings around the cooling system to identify/locate problems associated with the heat-rejection process (Figs 5, 6). Each of the three temperature differentials identified in the right-hand columns of both figures relates to the performance of one cooling-system component (tower, circ-water flow, and condenser heat-transfer resistance).

These differentials easily can be compared to their design values, the values seen during acceptance tests, or the values from a previous time (of similar ambient conditions) when the plant believed no problem existed. If there is a significant issue, it can be identified easily with this simple approach.

Again, there are methods to determine these parameters with greater accuracy (that is, more complicated calculations), which will better correct for external conditions—such as plant load and ambient conditions. But if plant personnel suspect a given cause of higher-than-expected backpressure, this simple technique seldom fails to find the culprit.

Root cause. To make the performance-monitoring process truly valuable to the plant, it's critical that the analysis not stop simply with a report that states the main problem is caused by, say, "low GT inlet air flow." This condition can be attributed to many things—each of which is related to the physical condition of the filters, IGVs, and/or the first few stages of the compressor.

Similarly, any lower-than-expected performance parameter, if calculated correctly, is caused by some aspect of the physical condition of that component. Like in the car-mileage example above, making the connection between the observed deficiency to a proposed solution is what separates a successful performance-monitoring process from just a report.

Tools of the trade

Good instrumentation is required for the level of monitoring described, but bear in mind that "good" and "expensive" aren't necessarily related. There are many references to the PTCs when discussing performance monitoring. However, for the purpose of monitoring for degradation, the objective is not comparison to an absolute baseline (such as a contractual guarantee), rather change relative to a baseline. The bottom line: Much of the philosophy behind the PTCs is inappropriate for routing monitoring and trending.

If the same instruments used to establish the baseline are used in monitoring, and if they are calibrated with reasonable care, they should have the accuracy and repeatability required for conducting a successful performance assessment program.

Heat-balance program. After the plant engineer becomes more familiar with the theory and application of performance monitoring techniques, he or she will want to take the next step, which will require a more powerful tool—a heat-balance model. This is a computer program that can predict performance given a set of inputs—such as percent load, ambient conditions, etc—or can back-calculate equipment performance when test data—such as flows, pressures, temperatures, and plant output—are entered.

If you already have a heat-balance program, devote as much time as you can to learning how to use it correctly; make full use of any user support offered. If you don't have such a program, consider investing in one. Keep in mind that the old adage of "garbage in/garbage out" applies as much as for any computer tool. While they may look easy to use, these programs are complex tools. It will take a while before a newcomer is capable of making meaningful recommendations using the results of any but the most basic heat-balance cases.

How to start. If a plant doesn't have a performance monitoring process in place, now is a good time to start. Years ago, when utilities dominated the power-generation business, they and the architect/engineers serving them had budgets to support graduate engineers as they learned the ins-and-outs of heat balance, performance testing, and heat-rate analysis. Writing reports was one way to teach and develop young staff members.

Those days are long gone. Although ISOs and price bidding have replaced power pools and incremental heat-rate curves, the need for accurate performance curves, identification of losses, and cost-justifying performance-related maintenance are more important than ever.

Today's options

Performance monitoring is necessary and can be done; it's just a matter of "how." There are three typical

Summary of plant reference data

Parameter	As tested	Corrected	Baseline	Deviation MW*	Deviation %
GT1 output, MW	176.3	178.2	180.1	1.9	1.1
GT2 output, MW	170.1	171.9	181.6	9.7	5.3
ST output, MW	175.2	177.6	178.2	0.6	0.3
Aux power, MW	8.1	8.2	8.2	0.0	0.0
CC net output, MW	513.5	519.5	531.7	12.2	2.3

*Difference between baseline and corrected values

approaches: Assign the responsibility to (1) an expert attached to the central engineering staff if your organization has one, (2) a capable plant employee, or (3) a third-party specialist.

Support personnel available. For plants owned and/or operated by a generating company with an engineering support organization, performance monitoring is a relatively straightforward proposition. The support staff usually has a performance engineer with a budget for analyzing performance and improving one's skills and knowledge base. Other staff personnel usually are available for developing procedures, tools, spreadsheets, etc.

There are several fine software programs and "packages" available for an individual with the time and expertise to use them correctly. Example: One staff engineer chose a "package" suitable for both control-room operator displays and engineering modeling. With serious effort, he developed himself into the company's performance expert. The screens selected are used productively by operators and management alike, and the software vendor usually provides excellent support and updates.

Plant on its own. For plants that don't have access to a dedicated support staff, performance monitoring isn't impossible, but it requires a different approach. The first step is to identify the proper individual to handle the assignment. The ideal candidate will have the following capabilities/attributes:

- Basic knowledge of thermodynamics, heat transfer, and fluid mechanics.
- Skill in performing calculations.
- Proficiency with spreadsheets.
- Common sense.

However, this approach isn't necessarily the way to go for the small standalone facility, or one in a small portfolio of plants, where staffing is limited and the plant engineer already serves as the de facto compliance officer, chemist, metallurgist, rotating-equipment specialist, etc.

The performance guy (or gal). A cost-effective method for providing your plant the performance monitoring services need is to use what could be called the "water chemistry" model. Virtually all plants without direct access to a corporate or on-staff chemist has a water-chemistry rep who visits regularly, knows the plant's water chemistry needs, and is usually the first number on auto-dial whenever there's a water-related question. He or she typically is treated as a "member of the family," seated on the same side of the table as plant personnel in vendor discussions, to provide technical assistance and protect the plant's interests.

A plant with limited staff resources could follow the same approach for performance management. This independent expert can provide periodic performance reports with trends, bullet-point items of concern, observations, and recommendations. With Internet conferencing, it's easy to have meetings with plant management, operators, I&C, and maintenance personnel. Plus, when technical discussions with the OEM are required, there will be a performance professional on your side of the table. CCJ

Jim Koch has more than three decades of experience in heat-balance and plant-performance work. He has spent the last half of his career in private practice; previously, he was employed by an electric utility and architect/engineer. Education: BS and MS degrees in Mechanical Engineering from Rensselaer Polytechnic Institute.

To dig deeper into the subject matter described, write jameskoch@verizon.net for a copy of the author's technical paper, "'Common sense' performance monitoring for combined-cycle plants in a competitive industry."

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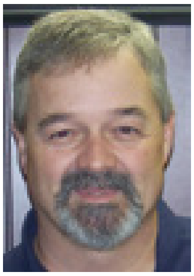
Repair of tube leaks: The good, the bad, the ugly

All owner/operators of combined-cycle and cogeneration plants will tell you they "want a good job," especially when it comes to the repair of boiler pressure parts—tubes, for example (Fig 1). However, many do not realize that job quality depends in large measure on their involvement in the repair project.


Kitterman


Morse

The starting point is contractor selection, Bill Kitterman and Bob Morse of Bremco Inc, Newport, NH, told attendees at a recent Combined Cycle Roundtable sponsored by the Combustion Turbine Operations Technical Forum (CTOTF). Price is very important, but it's not everything, the repair experts advised. If your due diligence of alternative service providers is incomplete and you hire a contractor without the specific capabilities required to ensure project success, they continued, your expectations may not be achieved.

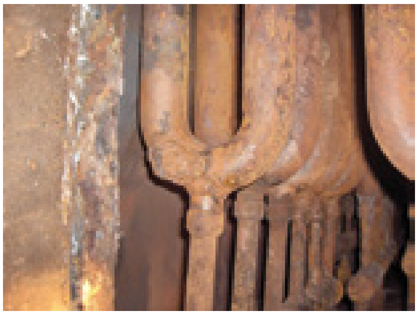
Kitterman had presented in detail on "How to select the right contractors to support your next outage" at an earlier Frame 6 Users Group meeting. You can obtain a summary of his remarks before that forum by accessing the 3Q/2006 issue at www.ccj-online.com.

The plant's responsibility doesn't end with contractor selection, Morse said. One or more members of the owner's O&M team should be assigned to follow the project and ensure that the work being done satisfies the company's requirements. Kitterman flashed samples of ugly work up on the screen (Figs 2, 3), noting that just because the weld holds a hydro doesn't mean it was done correctly. The backside weld shown in Fig 4 illustrates the "good" workmanship most owners expect.

Plant staff should prepare for a contractor's visit with a thorough review of the job plan, weld procedures including QC hold points, and welder qualifications. Kitterman suggested obtaining the continuity logs for welders. It's important to verify that each welder has struck an arc within six months of your project's start using the process/procedure required for your work—a Code requirement. Continual practice is required; perfection can be illusive. The mirror test jig in Fig 5 is used for both practice and welder qualification.

Closeout paperwork provides a complete record of the job and is extremely important to obtain and retain. The package should include detailed work procedures followed, welder qualifications, identification of welders for specified, materials


1. Tube leaks can be expected in HRSGs with poor drain systems



2, 3. Ugly "repair" of U-bend passed hydro (left); section through the weld area is at right



4, 5. Good weld on back side of tube was made using mirror; mirror test jig for practicing welds and for qualifying welders is at right

6, 7. Jumper piping is cut (left) to allow raising of the panel at right for tube repair

receipt and test reports, QC documentation, drawings, copies of official reports on code work, safety record, cost, etc.

Much of this information is included in the "Form R-1 Report of Repair" provided in accordance with provisions of the National Board Inspection Code (NBIC). More is recorded in the so-called "Job Traveler," which describes major project activities—final visual inspection, for example—and the names of the contractor's QC inspector and NBIC Authorized Inspector (AI) signing off on each.

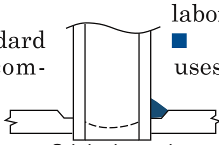
Planning the job

Kitterman and Morse spent most of their time at the front of the room walking users through typical pressure-parts repair activities, to prepare them for the types of work that would be done in their plants and decisions they might be involved in. Regarding decisions, consider the following:

- When a leak occurs, do you take the unit out of service or continue to run?
- How do you "fix" the damage: patch, repair, replace?
- What type of weld repairs do you want in your boiler?
- Should you perform NDE beyond that required by the Code—such as sample analysis?

Tube-to-header weld designs were first on the list of discussion items. If you're involved in developing specifications for replacement tube panels or repairs required for a replacement harp, you have to speak the same language as the fabricator or contractor. Terms you should be familiar with are bulleted below. At this point in the presentation, Morse banged the company drum for a minute. In over a decade of repair work on HRSGs ranging from aero to F-class sizes, he said, Bremco has never had to plug a tube.

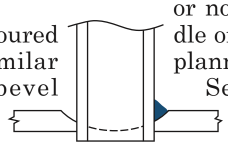
- Stick-through with standard "J" bevel is the most common tube-to-header joint configuration because it meets the HRSG designer's performance requirement and is the least expensive weld joint for panels. The fillet weld used does not require the higher level of skill that an open-root weld demands, so you can expect consistent top quality for these joints from experienced welders.



Stick-through, standard J bevel

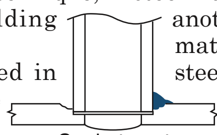
8. Panels are jacked apart to provide access to leak area

- Stick-through with contoured weld groove is very similar to the standard "J" bevel design, but by articulating the "J" bevel around the hole contour a weld groove of constant depth is achieved on both the high and low sides of the header tube hole. It can require more filler metal than the standard "J" around the low side of the joint, depending on the weld technique, but the additional welding generally is negligible.



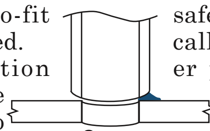
Stick-through, contoured weld groove

- Socket seat is often used in upper headers because the design facilitates draining. This is not to say that other joint configurations cannot be made to drain as efficiently. If both upper and lower headers are specified with this joint, additional trim-to-fit labor normally is required.



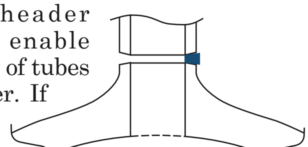
Socket seat

- Set-on configuration uses a header tube-hole diameter equal to or smaller than the tube ID. This joint requires an open-root weld and the back side is inaccessible; therefore, it demands a higher degree of skill from the welder than is required for most other joint configurations.



Set-on

- Spot-face set-on, similar to the set-on, eliminates the need to fish-mouth the tube end by spot-facing the header. This also is an open-root weld, but the recess can make for more difficult access to the root. It may require double the welding labor than that required for the simple set-on joint.
- Extruded-header tube holes enable butt-welding of tubes to the header. If both upper and lower headers are of the extruded design, additional trimming of tubes typically is required during tube fit-up. This can be avoided by designing the lower header with stick-through joints. Additionally, this joint uses an open-root butt weld, which requires greater skill on the part of the welder than some of the other joints shown.

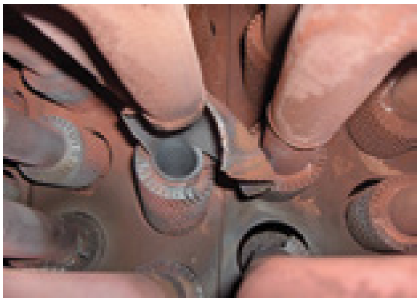


Extruded header

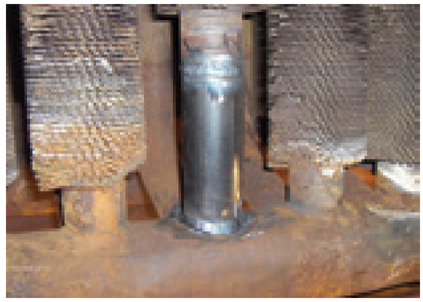
Find the leak. If you the owner/operator finds the leak, your company will reduce the cost of repairs. Pinpointing the leak location for the contractor—such as, section of unit, upper or lower half of the boiler (or elsewhere), at a tube-to-header weld or not, header location (in a bundle or in the open)—facilitates job planning and execution.

Selecting the optimal repair method is next. Depending on where the leak is located, access may require raising or lowering one or more panels, or jacking apart the panel with the leaker and the harp next to it. It might be expeditious to cut your way in and weld your way out, but be sure the necessary amount of tube stock is on hand. Tube plugging is another option to consider. Tube material (T91, T22, T11, carbon steel) will impact the repair process; know what's in your HRSG and where.

Raising (or lowering) a panel to make repairs demands experience (Fig 6). The task must be carefully thought out to minimize the number of steps and assure a safe work environment. It typically includes cutting of jumper piping (Fig 7), drains, etc; use of restraints to hold the repositioned harp in place while work is done; stress relief; rigging. Jacking of panels also involves cutting restraints and

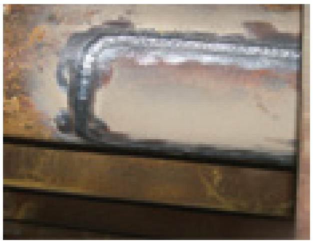


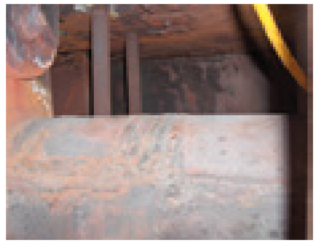
9. Freeze-up of undrained water fractured tubes



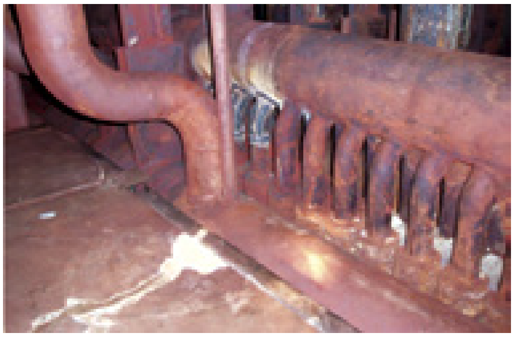
10, 11. Old tube section removed, header hole is cleaned up (left) before dutchman is welded in (right)

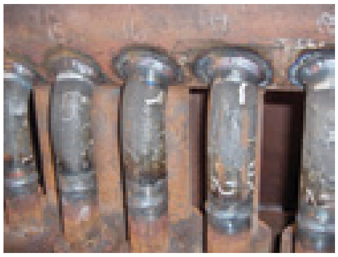
12. Plugging of tube through header should be the solution of last resort





13-15. Good header patch (no sharp corners) is at left, bad patch with squared-off corners is in center, ugly patches with square corners are at right





16-17. Improper repair is to cut window out of tube (left); right way is to install dutchman

18-19. Puddling weld material is not a proper repair (left); professional weld is at right

drains and requires proper blocking (Fig 8).

Tube leaks typically are traced to flow-accelerated corrosion, rapid quenching of hot tubes caused by improper operation of header drains during startup or leaking attemperators, etc—even freeze-up of undrained water (Fig 9). The majority of tube leaks is located near the upper or lower header and the typical fix is to cut out the damaged material, dress the header penetration (Fig 10), weld-prep the open end of the remaining section of tube, and weld in a stub (Fig 11).

At first glance, it would appear that all this effort could be saved by tube plugging. But plugging is not as simple as it sounds. Kitterman and Morse said this was the least-desirable solution in their minds, one involving strong Code involvement and a high level of skill (Fig 12). In all probability, stress relief of affected headers will be required.

Plugging a tube requires cutting into the top header to install the plug. Repairing the header after the plug is set requires cutting material from a new header to serve as the patch. The patch is cut out slightly oversize and fit-up is accomplished by grinding off the heat-affected zone. The header must be stress-relieved after the patch is welded in place. A good patch is shown in Fig 13, a bad patch (square with sharp corners that cause stress risers) is illustrated in Fig 14, and an ugly arrangement of two square patches side by side, with a generous supply of weld bead, presented in Fig 15.

All repairs must be made according to one or more codes, Kitterman continued. "Code" is not just another four-letter word, he said, it's the law. NBIC, ASME, and/or state or local codes may apply. An AI sees to it that repairs are made properly. For example, cutting out a damaged section of tube and replacing it with a window (Fig 16) is the wrong approach; the dutchman in Fig 17 is the correct way. Likewise, the wrong and right ways to fix a leak are illustrated in Figs 18, 19.

The welding processes most often used in making boiler repairs are (1) GTAW (TIG), SMAW (stick), and a combination of both. Each has its pros and cons. For example, the benefits of TIG are cleanliness, purity, and manageable weld profile. Stick is faster. The combination offers you the best of both worlds. The negatives: TIG requires highly skilled welders and the process may be sensitive to local conditions. Stick welding requires skilled welders to get the proper results, plus proper rod selection is a critical element of the process. Rod control once the job gets rolling is critical; mixing of rod types will adversely impact weld quality. CCJ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That's not your father's gage glass

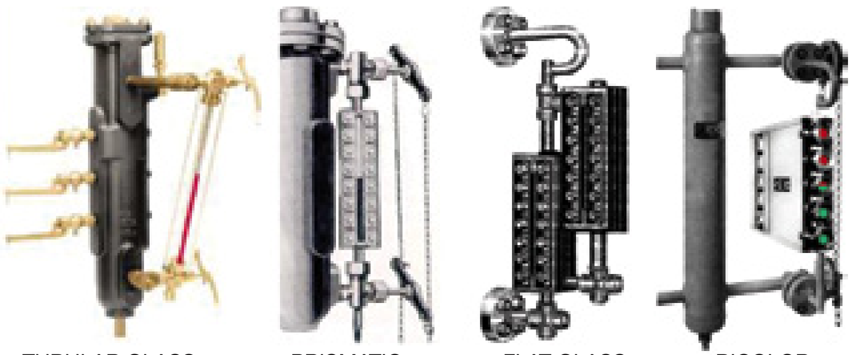
Drum-level gage glasses have been reliably protecting deck-plates personnel and the public at large against boiler failures since well before the industry's oldest operator was born. But while today's direct- and indirect-reading drum-level instruments may look like those installed on your aging heat-recovery steam generator (HRSG), improvements have been ongoing.

Jim Kolbus, product manager, Clark-Reliance, Strongsville, Ohio (Sidebar), speaking at the 20th annual meeting of the HRSG User's Group, held earlier this year in Houston, brought owner/operators up to date on this vital safety equipment. He began by reviewing the different types of gage glasses.

The only direct-reading drum-level gage is a glass gage, Kolbus said, and there are four types of these, as shown in Fig 1: tubular, prismatic (also known as reflex), flat glass (transparent), and bicolor (ported). Note that the last operates on the principle of light refraction: Light refracts through water differently (green) than it does through steam (red). The gage must be equipped with an illuminator to comply with Section I of the *ASME Boiler & Pressure Vessel Code* (Code).

The instrument expert stressed that the tubular glass option is not recommended as a permanent installation because it offers the least protection for plant personnel. It's fine for boil-out and chemical cleaning purposes, he said. Prismatic gages typically do not require any illumination accessories, Kolbus continued. They are easily viewed in areas with sufficient ambient lighting.

Flat-glass gages should have illumination accessories. The instruments are designed with inner mica shields, which reduce an observer's ability to read the level accurately when installed without back-lighting. Bicolor gages generally are the only option above 2000 psig; however, they are used as well in low-pressure applications because it's easy to see the water level.



1. There are four types of direct-reading gage glasses (l to r): Tubular (up to 250 psig), prismatic (up to 350 psig), flat glass (up to 2000 psig), and bicolor (up to 3000 psig)

Indirect-reading water-level indication systems may be any combination of the following types: (1) differential pressure, (2) guided-wave radar, (3) conductivity probe-type systems with a control unit and remote display, and (4) magnetic level-indication systems designed with a float in a stainless steel chamber. However, the use of magnetic level-indication systems is limited by the Code to 900 psig.

Clark-Reliance in your plant

Clark-Reliance, founded in 1884 as the Reliance Gauge Column Co, is the industry's leading supplier of gage glasses and other mostly "invisible" plant equipment—such as transmitters, level switches, liquid separators, sight windows, flow indicators, steam traps, small valves, hydraulic-oil filters, etc. The company's brands that may be familiar to you include Jerguson, Magne-Sonics, Jacoby-Tarbox, Clark Steam Specialties, National Filtration Systems, Anderson Separator, Hycoa, and Oil Filtration Systems.

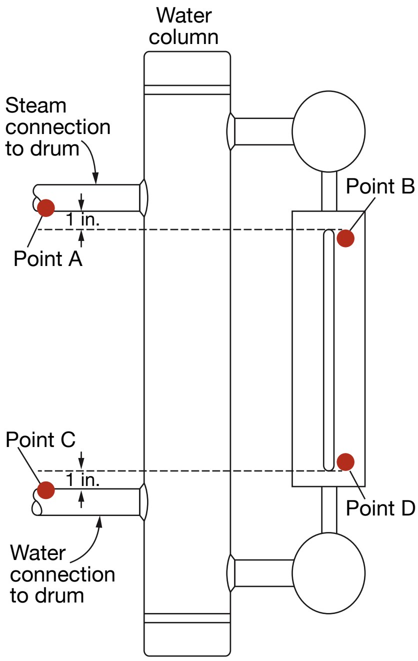
The first two indirect-reading gages must be installed and programmed in accordance with the manufacturers' instructions to prevent indication errors. Also, Kolbus recommended that users take precautions to prevent adverse effects of freezing conditions on level-sensing components.

Code requirements

The ASME Code mandates that one direct-reading gage remain in service at all times on applications up to 400 psig. The logic is that boilers in this pressure range generally are specified for hospitals, universities, district heating systems, etc, and are close to large numbers of people. Having the most obvious and accurate water-level instrument in continuous service contributes to a high level of safety.

For boilers operating at pressures in excess of 400 psig there are two options: Two direct-reading gages or two indirect indicators on continuous display for the operator and one direct-reading gage. Last may be isolated but must be maintained in serviceable condition.

Fig 2 is important because it illustrates Code rules for locating a water gage glass with respect to the piping between the drum and the water column. Goal of the arrangement is to assure installation of a gage with



2. Code requirements for gage-glass placement are defined in the diagram. Key points to remember:

- The lowest visible part of the water gage glass must be at least 2 in. above the lowest permissible drum water level (defined as the level at where there is no danger of the drum overheating).
- The top of the water connection from the drum to the water column (Point C) must be at least 1 in. below the low visibility point of the gage glass (Point D). The water connection line must be at least 1 in. NPT and be level or slope downward from the column to the drum.
- The highest visible part of the glass (Point B) must be at least 1 in. below the bottom of the steam connection (Point A). The steam connection line must be at least 1 in. NPT and be level or slope upward from the column to the drum.

unimpaired visibility that fills to the top of the required visible range and can be drained completely.

Some attendees seemed surprised to learn that the gage-cock connections found on water columns of older installations to provide positive verification of water level, if necessary, are no longer required by ASME Section I—and haven't been for 20 years.

Kolbus then reviewed various subsections of Section I that pertain to drum-level instrumentation. One concerned the ball check valves installed in gage glasses. They are designed to restrict flow to the gage glass in the event of breakage or a significant leak, he told the group.

The Code requires a vertical rising ball in the lower valve; the ball is not permitted to completely shut off flow to avoid valve sticking or trapping of water in the gage glass. Clark-Reliance achieves this objective by providing an irregular surface on the ball-check seat that greatly reduces flow to the gage glass while preventing complete shutoff.

However, use of a ball check can inhibit blow down of the gage, Kolbus continued. Some users report the need for more frequent gage glass repairs because of contamination in applications with ball checks.

A good safety measure is to install chain operators so the water valves can be operated from a safer distance in the event of a leak. When setting up chain pulls on quick-closing lever-actuated valves, position the levers so they aim downward toward the 5 o'clock position when the valves are closed.

Materials specified by the Code for construction of drum level instrumentation were the next topic. Stainless steel is acceptable for gage glasses and magnetic level indicators. A list of the acceptable grades of stainless is published in PG-12.3 in Section I.

Interestingly, the Code does not mandate the use of a water column to support the water gage glass; however, it does define the rules for construction of water columns (PG-11 in Section I). In many situations, use of a water column is the only way to adapt a gage glass to the vessel and achieve the required visibility range. Note that the water column and lower water gage valve both must be installed with drain piping and valve to a safe discharge location.

Use of magnetic level gages on boiler drums is not without its concerns, including the following:

- Float design is based on operating conditions (customer specified), not boiler design conditions. Impact: If the boiler is operated at a pressure lower than the planned operating pressure, the magnetic gage reading will be higher than the actual drum level.
- If the user has poor water quality, the potential exists for iron particles to attach to the float. Impact: The float's weight increases, thereby producing an inaccurate level reading.

Low-water cutouts received their deserved attention. Two devices are required by the Code, as specified in Section CSD-1 (not Section I), "Controls and Safety Devices for High-Pressure Steam Boilers," Subsection CW-140. These devices typically are activated by floats or conductivity probes. Important: The two devices must be in separate chambers or one of them may be inserted directly into the drum.

One control must be set to activate ahead of the other one. A manual reset function may be applied to the lower of the two controls, this to assure that the operator confirms there's a safe water level in the gage before activating the reset. Additionally, the cutout circuit may incorporate a time delay not to exceed 90 seconds, thereby allowing the operator a little more time to regain a safe water level in the boiler without initiating a shutdown.

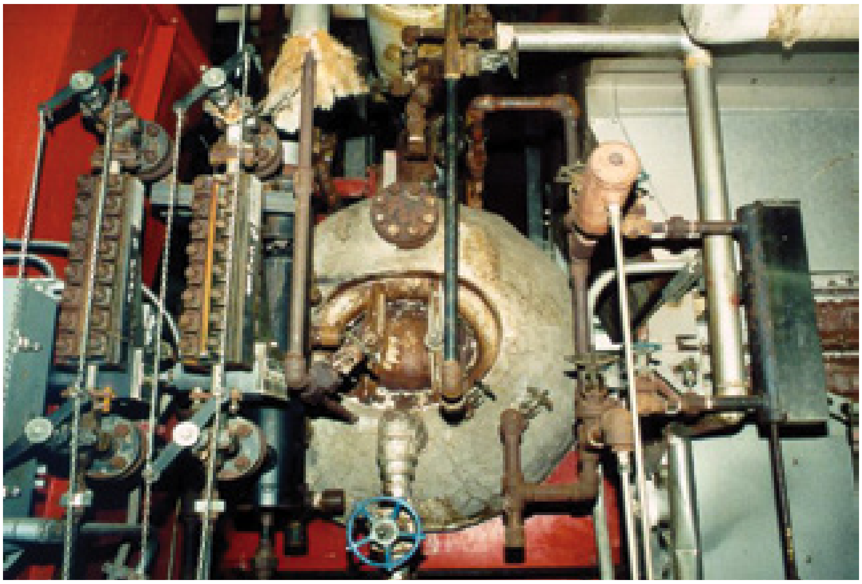
Piping recommendations. Best practices regarding level-instrument piping include the following:

- All piping from the drum to water-level instruments must be insulated to (1) protect personnel against burns, (2) assure accuracy of level measurement, (3) minimize condensate formation. Keep in mind that condensate contributes to erosion of the mica shield in the gage glass: The less condensate, the less wear.
- Any piping slope should be downhill on the steam line and uphill on the water line from the drum (Fig 2).
- Regarding piping runs from the drum to level instruments, less is more. The shorter the run the less temperature loss; plus, the likelihood of more accurate level indication.

Common Code violations, concerns. Kolbus noted that he finds too many of the violations listed below in plants visited and stressed that users review Code requirements to assure the highest levels of plant and personnel safety. Violations and concerns include these:

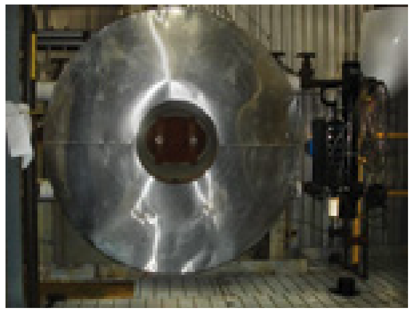
- Isolated, inoperable water gages.
- Missing water gage glasses.
- Missing illumination from ported-type gages.
- Inadequate display of remote level indicators in the control room combined with isolated gages.
- Contaminated water gage glasses that prevent viewing the actual level (meniscus line). Confusion can result when a contaminated water gage causes a stain at the water-level line—especially on neglected tubular glass applications. On higher-pressure gage glasses, a white color on the inside of the glass may occur when the mica shield has deteriorated. In both cases, immediate maintenance/replacement are required.
- Multiple-section flat glasses without the Code-required overlap.
- Poor maintenance practices.

Inspection results compiled by the National Board of Boiler & Pressure Vessel Inspectors in its Annual Violation Tracking Report reveal boiler controls (including gage glasses) leading in "number of violations." In



3. Drain piping on the lower right side of the drum should not have a trap. The low point must have a valve. This Code violation was corrected by the plant owner

4. Incorrect: Steam and water piping to water column slope downward



5. Correct: Relocated water column is alongside the steam drum

2010, the last year for which complete data were available when Kolbus prepared his presentation, boiler controls accounted for 29% (21,158) of the 71,816 violations found during 688,963 inspections.

His conclusion was that the stats would improve significantly if operators had access to proper training and support. Since the beginning of this year, inspectors have been detailing the causes for boiler-controls violations. This will permit extraction from the data of those violations attributed to water level gages, cutouts, etc.

Case histories. Fig 3 illustrates both the good and the bad in one gage glass installation. The good: Chains on water gage isolation valves are properly installed as is the drain piping on the water gage valves and water column. The bad: Drain piping on the lower right side of the drum should not have a trap. The low point must have a valve. This Code violation was corrected by the plant owner.

Fig 4 illustrates a water column installed incorrectly, with steam and water inlet piping sloping downward. This dangerous installation never was placed in operation. The low-water alarm and low-water cutout probes would have indicated trapped water in the piping and the gage glass would have responded similarly. Corrective action is shown in Fig 5. Water column was relocated near the drum and the gage glass and conductivity probes in the water column are in the correct position relative to the drum. CCJ

Maximizing the productive lifetimes of gas-turbine assets

By Ron Munson, PE, Ron Munson Associates LLC

During the 1980s and 1990s, many electric utilities were challenged to extend the lives of their power generation assets. Some units were rapidly approaching, or even beyond, their design lifetimes of 30 to 40 years and economic necessity demanded that these assets continue to operate safely and with a high degree of reliability. EPRI and others adopted strategies for life extension based, in large part, on the results of nondestructive examination (NDE) and metallurgical evaluation of critical components.

However, the rapid acceptance of gas-turbine-based generation to meet increasingly strict environmental laws and other regulatory edicts, eventually de-emphasized life-extension initiatives for conventional fossil-fired steam/electric plants.

Today, GT owner/operators are the ones facing life-extension initiatives. Inexpensive gas has displaced coal generation on an economic basis in many areas of the country and aggressive environmental rules are forcing the shutdown of other coal-fired stations. Gas turbines are working harder and longer to meet electric demand.

At the same time, OEMs are telling GT users their prime movers have critical parts with finite lifetimes and that replacement of these parts is necessary to assure reliability and safety moving forward. It remains unclear at this time if the sudden emphasis on the lifetimes of parts is technically or commercially driven.

The technical discussion that follows reviews life-limiting deterioration mechanisms for some critical parts and offers owner/operators guidance in life-extension decision-making.

GT basics. Life-extension specifics depend in part on the type of gas turbine: frame or aeroderivative. The former are the most robust and shoulder the burden in terms of kilowatt-hours produced; the latter, lighter and typically smaller, are valued for their fast-start/ramp capability to meet peak demand and respond quickly to changing electrical requirements.

Life-extension issues are not as relevant for aeroderivatives as they are for frames because their modular construction permits routine replacement of critical engine sections over the life of the unit. Thus, the focus here is on frame engines.

When a generating company invests in a gas turbine, life expectancy usually is not high on the purchaser's list of priorities. Delivery schedule, price, emissions, and heat rate typically are viewed as more important. For the most part, owners have assumed that GTs will be fit to operate well beyond the useful economic life of the facility in which they are installed.

Until recently, gas-turbine designs and materials capabilities had advanced the replacement of older frames on the basis of economics. Ever decreasing heat rates allowed relatively quick recovery of capital investment and provided the justification for ordering new rather than upgrading old. But the inability to recoup capital investments quickly today and thermodynamic limits on efficiency improvements have shifted emphasis once again to life extension.

GT users understand that many expensive hot-gas-path parts, such as combustion-system components and turbine airfoils, must be replaced or repaired regularly. With this a "given," life-assessment issues focus on more durable components, such as casings and rotors, which are considered by most owners to have very long, if not infinite, lifetimes. They are costly to replace and lead times are long.

Casings for industrial gas turbines usually are robust, made of cast carbon or low-alloy steels. These components are quite large and are unique to a certain model, and often to a particular serial number, of a machine. Casings are characterized by many welded-on pieces—such as nozzles and flanges—which typically are added during manufacture with the attachment welds being appropriately heat-treated.

Replacement casings for legacy machines may no longer exist, the original fabricator having gone out of business and casting patterns destroyed. Repair of some old casings may require an expensive weld, heat treatment, and remachining—including line boring. The total cost could approach that for a new casing were one available. Replacement with a used casing may be an alternative, but its history is likely unknown and the pedigree questionable.

Guidance on casing repairs is offered in a companion article, "Four 'knows' help identify a viable approach for dealing with casing cracks," p 64.

Rotors for most gas turbines are forged low-alloy steels, heat-treated to obtain a balance between strength and toughness. They can be constructed from a single forged ingot, end to end. But because of forging size constraints, the majority of GTs are built from multiple forgings that are mechanically bolted or fastened together. One OEM welds its forgings together rather than using a mechanical joint. A material exception is GE Energy, which fabricates the wheels for its F-frame turbine from a nickel-based superalloy.

Damage mechanisms

There are many damage mechanisms conducive to the retirement or extensive repair of a GT casing or rotor. Listed below, they can be either short- or long-term in development. Life-extension activities are influenced primarily by the latter, especially "wear and tear" issues.

Short-term or random mechanisms include the following:

- Foreign-object damage (FOD).
- Domestic-object damage (DOD).
- Distortion or buckling from cool-vapor introduction.
- High-cycle fatigue (HCF).
- Environmentally induced cracking (stress corrosion cracking, SCC, or corrosion fatigue, CF).

Short-term mechanisms usually

are not a major concern in evaluating the life exhaustion of either a casing or rotor. Periodic borescope examinations, scheduled inspections, and installed instrumentation usually will point to damage that has occurred or will be occurring.

These mechanisms typically are precipitated either by random or unpredictable events—such as DOD, FOD, trips, or cool-vapor introduction. HCF typically is related to design—improperly tuned blades, for example—and normally occurs early in the life of the component. Corrosion fatigue and SCC are rare, but usually predictable, if one understands the GT environment.

Long-term or progressive mechanisms are these:

- Thermal mechanical fatigue (TMF).
- Low-cycle fatigue (LCF).
- Creep.
- Corrosion.
- Hot corrosion.
- Fouling.
- Erosion.
- Distortion.
- Wear/fretting loss of dimensional tolerances.
- Microstructural ageing and embrittlement.

Long-term mechanisms are the ones most responsible for casing and rotor life-exhaustion issues. Both TMF and LCF depend directly on cycling; magnitude of the damage is influenced more by ramp rate than by the number of cycles.

Creep is very temperature-dependent. In fact, there are temperatures below which a material is not going to suffer creep damage. Keep in mind that, while creep is related directly to firing temperature, casings and rotor, if properly cooled, may be operating below the creep initiation temperature for their alloys of construction. Fortunately, creep damage occurs with deformation, which is conducive to rubbing of components and does not lead to catastrophic failures.

Corrosion, hot corrosion, fouling, erosion, and loss of dimensional tolerances are slow to accumulate and quite progressive in nature. They are detectable by visual examination if their locations are accessible, and become problematic when they cause cooling passive disruption, or the corrosion products that form result in loss of clearances. Clearance loss can lead to rubbing or loosening of parts and contribute to fatigue or wear.

One particular issue is that corrosion products (rust) from the steel compressor case enter the hot section and cause a change in blade damping characteristics, thereby contributing to fatigue failures. Another example is that blades on turning gear will fret against adjacent blades and their attachment points, and change blade fit-up, resulting in HCF from poorly damped, harmonically induced vibration.

An important issue that must be faced in life extension is the long-term ageing of construction materials. Most steels, and even superalloys, are meta-stable in the condition they are used in gas turbines. (This means they want to be in a lower thermodynamic energy state than where they currently exist.) At room temperature, the time it takes to get to the thermodynamically stable state is very long, if not infinite.

However, the GT's high-temperature/high-stress environment wants to push the meta-stable structure to stable structure in measurable times. This is analogous to in-service heat treatment. Such an alteration can have a dramatic impact on component performance. Examples are gas-phase embrittlement (hold-time cracking) in GE hot-section discs, graphitization of carbon steel in compressor casings, and temper embrittlement of low-alloy-steel rotors.

Drivers for damage. Each damage mechanism has a primary driver. The mechanism could be caused by cycling (such as TMF), be related to fired hours (creep and erosion), or attributed to random events. Last could be FOD from the inadvertent introduction of objects during outages. Machine operation, configuration, and maintenance also have a huge impact on susceptibility. Some factors to consider when doing life-extension studies are the following:

- Time on turning gear.
- Fuel quality.
- Inlet-air conditioning and filtration.
- Equipment environmental protection during outages.
- Procedure for compressor water washing.
- Environmental control equipment—such as low-NO_x combustors.
- Firing temperature (design versus actual).
- Quality and knowledge of overhaul contractor.

Risk-based approach. There are many avenues you can take to assess GT condition. One is the "Chicken Little" approach: You accept the OEM's recommendations without question and conduct the testing or replacements recommended at the intervals mandated. It is safe, but costly.

An alternative is to do nothing. While this approach has a low initial cost, it is likely to be very unpopular with your insurance carrier! Ultimately it could lead to severe financial penalties in property damage and lost power generation at a very inconvenient time.

A risk-based approach is more prudent: You consider each possible damage mechanism identified above and make an engineering judgment as to the probability of that mechanism being present in your engine. Judgment must consider operational factors, past inspections, and failures.

Risk has two parts: probability (likelihood) and consequence (severity). The consequence does not change with time alone. It depends considerably on contractual issues—such as power purchase agreements, which have significant variations in their terms. A part of risk is the consequence/severity of a failure that may occur. If the consequence part of the risk is low, it may be worth delaying assessment or replacement until conditions are financially favorable.

The probability of a failure does change over time. Example: The probability of failures resulting from certain damage mechanisms—such as wear, creep, microstructural ageing, LCF, and fouling—increase with time and/or more cycles.

However, there are relatively few data to use as a basis for quantifying the increase in probability over time. Many factors (called risk-modification factors) can greatly influence probability, which does not increase linearly with time or cycle accumulation. A prudent risk evaluation requires knowing what these factors are and how to apply them.

In sum, the key to a successful and cost-effective risk-based assessment of GT condition involves knowing where to look, what to look for, and what method to use to find the damage. In order to make these choices, one has to understand the history and features of the particular machine in question. Do not stereotype a machine based upon age, number of cycles, or model number. CCJ

Ron Munson, PE, is corporate engineer at Ron Munson Associates LLC, a metallurgical engineering and materials consulting firm headquartered in Round Rock, Tex. He has decades of experience in evaluating the condition of gas and steam turbines, reciprocating engines, high-energy piping systems, boilers, and related components and in recommending repair/replacement options where damage is in evidence.

Respect for water quality first step in achieving top plant performance

Cleanup and conditioning of compressor inlet air typically dominate the opening discussion sessions at most user-group meetings for gas-turbine (GT) owners and operators. Sometimes the caffeine-aided give-and-take on air filters can be relentless. Metal release from deteriorating silencers always gets its share of air time, as does leach-out of zinc from galvanized steel when fogging is the evaporative cooling medium of choice.

Occasionally, you hear about the agglomeration of fog particles and problems associated with the ingestion of large water droplets into the compressor, inlet bleed-heat issues, deterioration of evap-cooler media when undiluted demineralized water is used as the coolant, etc.

But it is the rare meeting where someone mentions issues with cooling-water chemistry in the air inlet house. Reasons why this is so include the following:

- There are no problems.
- No one is tracking water quality.

The second point is almost a given at many plants. The general level of expertise on things chemistry at the deck-plates level is "barely passing," if that—particularly in simple-cycle generating facilities. Add to this a general reluctance to climb up to the air inlet house and the inaccessibility of air cooling systems when units are in operation and you can understand why operating problems traced to poor cooling-water quality can exist.

The three short case histories below should give plant O&M personnel greater respect for the importance of water quality in turbine inlet systems. "Collateral Damage from GT Inlet-Air Cooling Systems" was compiled by David Daniels, Austin-based M&M Engineering Associates Inc's resident expert on water chemistry, and presented at the HRSG User's Group meeting last February.

That venue for this subject matter was interesting because GT inlet cooling systems have nothing to do with heat-recovery steam generators. However, you have to ask yourself, "When was the last time you saw a water chemist at a gas-turbine user-group meeting?" Probably never. But the industry's top water chemists usually attend the annual HRSG meeting and with their attention focused on Rankine cycle chemistry they might not be aware of water issues lurking elsewhere in the plant (Sidebar).

Perhaps this is the proper time to acknowledge the electric power industry's under-appreciated chemists. In the GT sector, 60% of the generating assets are owned by financial entities, many of which run their businesses strictly by the balance sheet. Chemists are an expense so there's considerable penny-wise/pound-foolish reasoning to support under-staffing.

It is not uncommon for a sizable GT fleet—say 5000 MW or more—to have only one chemistry professional on staff. Management justification typically is that with the sophisticated instrumentation and electronic data collection and transmission technologies available today, the "company chemist" can sit in his or her office and effectively monitor the fleet's health. If that's working for you, consider yourself lucky.

And, while there may be sophisticated chemistry monitoring devices for the steam cycle, these generally are absent on the balance-of-plant systems, such as evaporative cooling water.

FAC 2013: Mark your calendar

Unless you are regularly inspecting susceptible areas of heat-recovery steam generators, air-cooled condensers, and condensate systems for flow-accelerated corrosion (FAC), you're apt to be surprised one day by the significant loss of material from critical components. This despite the good report on the quality of cycle water received regularly from your chemical supplier.

Think of FAC as analogous to human disease. Everything might look fine on the surface, but underneath there may be serious concerns. It's important for plant managers to come up to speed on this insidious damage mechanism: Early identification and mitigation are important to maintaining top plant performance.

The 2013 International Conference on FAC in Fossil and Combined Cycle/HRSG Plants will be held March 26-28, 2013 at the Westin Arlington (Va) Gateway hotel. Many of your colleagues will be there to listen to the world's leading subject-matter experts and to participate in meaningful group discussions. Co-chairs for the meeting are Barry Dooley and Kevin Shields of Structural Integrity Associates Inc. Conference brochure is at www.ccj-online.com/fac2013. For updates, as they become available, and to register, visit www.facfossilhrsgconference.com.

The first FAC meeting, held in 2010, was attended by 170 scientists, engineers, and powerplant personnel from 21 countries and featured a technical program with 40 papers. Read David Addison's conference summary in the 2011 Outage Handbook, available at www.ccj-online.com (click "Archives" button in the tool bar at the top of the home page). Addison heads Thermal Chemistry Ltd, a New Zealand consultancy specializing in the management of powerplant water chemistry.

Water gremlins do exist, as Daniels' case histories attest, and they are unlikely to be identified in the early stages when generally easy to correct because hands-on site personnel usually are not trained to recognize the warning signs.

An option is to "let the water treatment vendor handle the chemistry." Besides having to overlook the obvious "fox guarding the hen house" issues that inevitably will arise, competent and dedicated professionals from this source also are rare. If you just happen to have one of them making regular (weekly) visits to your plant—a person interested in doing what is right for your facility rather than just selling the "latest and greatest"—consider yourself doubly fortunate.

Evap-media fouling causes turbine-blade deposits

The first case history involved a wetted-media-type evaporative cooling system. Plant personnel, puzzled by the rapid drop-off in electric production within a few weeks after evap coolers were restarted, scheduled an immediate borescope inspection. Deposits found on turbine blades (buckets) were so severe an outage was taken to replace the affected airfoils (Fig 1).

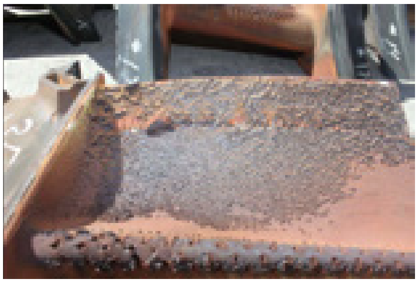
Investigation into the source of the deposits revealed accumulations of iron and other contaminants in the cooling water that were attributed to issues with the water-treatment process. The evaporative media was heavily fouled (Fig 2) and large quantities of loose deposits were found in the water trough under the media (Fig 3).

Analysis showed calcium, magnesium, aluminum, silicon, and iron in the deposits that would have come primarily from the makeup to the evap cooling water. Daniels believed that solids resulting from water-treatment process upsets collected on the media, flaked off, and got sucked into the compressor. The dry deposits formed a mixture that softened at temperatures reached in the combustion section, became sticky, and stuck on downstream airfoils.

One common mistake is using demineralized water for cooling in evap media systems. While free of both suspended and dissolved solids, demin is aggressive to the glue that holds the media together, and is not recommended. Depending on the water sources available to the plant, there may be several options—including softened potable water, well water, or blends of these and demineralized water. The most critical factor is that the water must be free of suspended solids, he said. At some GT user-group meetings attended by the editors, plant personnel sometimes suggest a 50/50 mixture of demin and city waters for inlet cooling service, but blending streams will require regular monitoring.

Daniels urged users to redouble their efforts to filter out suspended solids from evap cooling water and to install and diligently maintain filters on evap-cooler recirculation pumps where they do not exist. He then displayed the cooling-water specs for this service as recommended by ASME (Table). Daniels closed by suggesting users also check with their media suppliers to see if they have additional requirements for cooling water.

For a backgrounder on cooling of GT inlet air—including evap coolers, fogging systems, and chillers—read the special report on inlet-air systems in the 2Q/2010 issue, available at www.ccj-online.com (click "Archives" button in the tool bar at the top of the home page).



1. Iron and other contaminants in wetted-media evap cooling water stuck to turbine blades (buckets)

2. Evap cooling media was heavily fouled with contaminants

3. Contaminants accumulated in the wetted-media water trough

ASME recommended limits for evap cooling water*

Parameter	Normal value, ppm
Calcium hardness as $CaCO_3$	50-100
Total alkalinity as $CaCO_3$	50-100
Chloride as Cl	Less than 50
Silica as SiO_2	Less than 25
Iron as Fe	Less than 0.2
Total petroleum hydrocarbons	Less than 2
Total dissolved solids	30-500
Suspended solids	Less than 5
pH	7.0-8.0

*"Consensus on Operating Practices for Control of Water and Steam Chemistry in Combined Cycle and Cogeneration Power Plants" (CRTD-100; ASME Order No. 859988)

Bugs foul water circulating through mechanical chiller system

A generating station with two 2 × 1 F-class combined cycles in a hot and humid area of the country uses chilled water to cool compressor inlet air. To maximize power send-out during the daytime hours, the plant relies on a 6-million-gal thermal storage system to virtually eliminate the need to run mechanical chillers on-peak. During the cool months, when the chillers are not required, the system is winterized by flushing a glycol/water mixture through the coils before sealing up the system until spring.

Daniels said biofouling occurred in this chilled water system within a couple of years of commercial start and the presence of sulfate-reducing bacteria (SRB) was confirmed. The dilemma, he continued, was how to effectively treat a 6-million-gal concrete storage tank. He asked rhetorically, "What biocide do you use and how often to you treat the water?"

The water consultant concluded that complete treatment of the water inventory was impractical. There was no cost-effective way to sterilize a 6-million-gal concrete tank. So the solution focused on removing biofilm from the chilled-water piping and coils, where it has greatest impact. Chlorine dioxide was selected as the biocide because of its potency and effectiveness at high pH. The system is treated with this very strong oxidizing biocide in the spring and fall and at other times, as necessary.

Glycol leak wreaks havoc with cycle water chemistry

"No good deed goes unpunished," as the saying goes. That certainly was the case at a large plant equipped with four new LM6000 peakers, three conventional gas-fired steam units, and a 2 × 1 combined cycle. Demineralized water is produced by two independent systems: packed-bed ion exchange and reverse osmosis/mixed-bed demineralizer.

While most plants send their air-chiller condensate to drain, this facility suggested recovering it and using the nearly 170 gpm of pure water collected to reduce the amount of raw water withdrawn from wells supplying the plant with makeup. During the summer months, the quality of the low-conductivity demineralizer makeup recovered was excellent.

In February 2011, during a bitter cold snap, an improperly mixed glycol/water blend froze and tubes ruptured. Repairs were made and plant personnel believed "everything was back to normal." But about six months later, the hibernating gremlins awoke in the IP drums of both HRSGs; pH dropped to the mid 7s and stayed there.

There also was a slight pH depression in the HP drums and steam/condensate cation conductivity jumped up. However, there was no significant increase in sodium or chloride in the condensate, thereby eliminating a condenser tube leak as the cause. Both HRSGs were removed from service, drained, and refilled.

Day 2: Similar contamination symptoms (pH and cation conductivity) appeared in the gas-fired steam units. The source of that contamination was identified as glycol in the condensate being returned to the service-water tank supplying the ion exchangers.

Day 3: The HRSGs had the same pH and cation-conductivity problem when restarted because they were filled with glycol-contaminated water before the source was identified. After one more cycle of flush and fill, the contamination was eliminated.

Lessons learned:

- Organic contamination causes unusual chemistry symptoms.
- A little organic contamination goes a long way and takes a long time to clean out.

The plant has not given up on using condensate recovered in the air inlet house as a source of demineralizer makeup. But it will add a fluorescent dye to the glycol and install a fluorometer on the condensate-tank pump discharge to warn quickly of a leak. Interestingly, a sister plant also recovers moisture from the air, but it uses that condensate as cooling-tower makeup. This creates other interesting issues in cooling-water chemistry and corrosion. **CCJ**

Four 'knows' help identify a viable approach for dealing with casing cracks

By Ron Munson, PE, Ron Munson Associates LLC

A bad day for any plant manager is when a generating unit experiences a failure or circumstance that causes an extended outage. One serious, and increasingly common, issue that can force a unit out of service is cracking of a steam- or gas-turbine casing.

OEMs typically do not have casings in stock and lead times for replacements are long. If the casing can be obtained at all, it will be expensive. Repair of a cracked casing generally is a viable option; however, distortion from potential repair welding and metallurgy issues can make repairs challenging.

Casing knowledge is not widespread among turbine owner/operators, so a cracking issue must be approached deliberately. The four "knows" below will provide much of the information you will need to develop a viable solution.

1. Know casing chemistry and pedigree. Depending on machine age and design, the casing can be made from materials ranging from grey cast iron to low-alloy cast steel. Casing age also is important: It determines pedigree. Keep in mind that steel quality has improved over time, especially regarding the types and amounts of "residuals" in the material.

Casing alloy specifications may specify upper and lower limits for about 10 elements, but there are 15 to 20 or so elements that can adversely impact any type of weld repair. An efficient way to determine the exact composition of your casing is to slice off a small piece from a flange and submit it to a commercial laboratory for a "complete" chemical analysis.

Portable alloy analyzers can tell you what the basic alloy composition is, but they cannot identify some of the deleterious elements that can negatively affect welding—even at ppm concentrations. These analyzers are not useful for characterizing casings for repairability.

2. Know the root cause of the failure, the specific failure mechanism. Here are some of the questions you should ask yourself:

- Is the damage localized—such as in a highly stressed area?
- Is the damage from rotor interaction—such as rubbing, oxidation, etc?
- Is casing deterioration "global," such that repair at one location will be followed shortly by failures at other locations?
- Is your casing "deceased," or just "wounded?"

3. Know specifically what to expect from the repair. Will the repair be "permanent" and last the life of the machine, or "temporary," until you can obtain a new casing? Expectation of the repair life is important—influencing both the economics of power production and personnel safety. Regarding the latter, consider that a repair could change the casing failure mode from progressive—that is, crack elongation and more leakage—to catastrophic—the sudden and damaging release of steam or combustion gases under pressure.

4. Know your repair vendor. You're almost sure to identify many companies wanting to repair your casing. Be sure to choose the right one. Expect the high bidder to be the OEM, but don't toss that quote in the circular file at your first opportunity. The turbine supplier probably best understands your casing design and likely has repair experience on a sister unit or one similar to yours. Don't be surprised if the OEM would prefer to sell you a new casing, assuming one is available; it would have a lower risk profile and higher profit margin than a repair.

Non-OEM repair vendors probably will have the most competitive bids, but one or more might not have the experience to perform the specific repair you require. Thorough due diligence is necessary. The successful bidder should be a company specializing in casing repairs and one having a long and successful performance record. It's also very important to have the most highly skilled craftsmen assigned to your project; check resumes carefully.

Here's a checklist to help guide you through a casing repair:

- Photograph the damage.
- Examine nondestructively the balance of the casing. If damage is widespread your choices are (1) live with it, or (2) replace the casing.
- Define the probable failure mechanism and cause. Consider changes to O&M procedures to minimize the recurrence of cracking in the repaired casing.
- Remove samples; a small sliver from an area of low stress is sufficient. Verify composition of the casing material—including carbon level and residuals.
- Review casing history; note the location of previous repairs, if any. Also identify the type of repairs made and the vendor(s) that did them.
- Contact vendors both interested in doing your work and qualified to make the repairs required. Prepare a work scope, making sure to state the expected life you want from the casing. In addition, define post-repair inspection and acceptance criteria for cracks and distortion; clarify the warranty.
- Notify your insurance carrier of your intent to repair the casing. Future insurance coverage may depend on its knowledge that the repair was made.
- Conduct the repair. Have a qualified staff person or a third-party consultant monitor the repair. Your representative must be empowered to halt work if repair practices/procedures are not acceptable.
- Re-inspect the casing for defects both associated with the repair or new defects that came to light during the repair process.
- Return to service. CCJ

2013 BEST PRACTICES Awards

to gas-turbine-based powerplants (combined cycle, cogeneration, peaking)

Categories: Management, O&M, Safety, Design, Environmental
Deadline for entry: December 31, 2012

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A panel of judges with asset management experience will select for formal recognition at an industry event next spring, the Best Practices they believe offer the greatest benefit to the industry given today's goals of improving performance, reliability/availability, and safety, and reducing emissions and O&M costs.

RULES

1. Entries accepted only from employees of North and South American powerplant owners and third-party firms with direct responsibility for managing the operation and maintenance of gas-turbine-based electric generating facilities.
2. Maximum of three entries from the same powerplant.
3. Entries must be received by midnight December 31, 2012 via regular mail/courier, fax, or e-mail.

TO ENTER

1. Award category (select one): Plant or Fleet Management, O&M, Safety, Environmental Stewardship, Design.
2. Title of Best Practice.
3. Problem: Description of business or technical challenge motivating the development of a Best Practice.
4. Solution: Description of the Best Practice.
5. Results: Document the benefits gained by implementing the Best Practice. For example, percent improvement in starting reliability or plant availability, dollar or percent saving in annual operating cost or reduction in annual maintenance cost, improvement in man-hours worked without a lost-time accident, etc.
6. Name of plant.
7. Plant owner.
8. Plant personnel (and their titles and company affiliation) to be recognized for developing and implementing the Best Practice.
9. Contact for more information (name, title, company, phone, fax, e-mail).

Suggestions: (1) Do not mention the name of your company or plant when completing Parts 2-5. This is the information that will be submitted to the judges. (2) Limit your response to Parts 1-5 to the equivalent of two pages of single-spaced 12-pt type. (3) Add photos, drawings to support entry.

Refer questions/submit entries to:
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Learn from long-term experience in burning fuel oil

By Mike Hoy, Tennessee Valley Authority

With the US awash in relatively inexpensive gas, why an article on the storage, handling, and combustion of costly distillate fuel? Simple answer: There are many oil-only gas turbines under contract to support the grid, particularly in areas with large numbers of wind turbines. Most of these machines are relatively old and small by today's F-class standards.

Plus there are many dual-fuel engines now operating on a steady diet of gas that must be ready to run on oil in an emergency. Distillate degrades in storage and can cause handling and combustion issues if not maintained in good condition. Likewise, liquid fuel systems can adversely impact starting reliability if not exercised regularly and if layup procedures are not followed rigorously.

TVA has a great deal of experience firing oil in its gas turbines, the author told the 7EA Users Group at the organization's annual meeting in San Antonio last fall. The utility's oldest engines were installed as oil-only in the 1970s and converted to dual fuel as recently as the late 1990s. Today, the utility has eight sites with 83 dual-fuel machines (mostly GE Frame 5s and Frame 7s) in simple-cycle and combined-cycle configurations. Total dual-fuel capacity is 6255 MW.

Oil storage capability at the eight locations totals 74 million gal. One site alone has 23 million gal of tank capacity to support the operation of that facility's 16 Frame 7Bs for two weeks with all units at maximum load. Not all tanks at each site are full; oil inventory is maintained to support backup fuel requirements only.

Distillate quality, properties

Distillate sitting in storage tanks for years presents a fuel-quality liability. Water contained in the oil, and that added by condensation of moisture in the vented storage tanks, encourages the formation of bacteria. TVA drains water from its tanks monthly and adds state-approved biocides in the smallest quantities necessary to kill bacteria. Fuel oil is sampled and tested annually for PAD rating and biological fouling.

PAD, which may be a new term for many readers, is a measure of fuel oil decomposition and thermal stability. TVA's fuel spec requires new oil to have a PAD rating of 3 or less (the lower the number the more stable the oil), but that number will increase as the fuel ages and decomposes. The maximum PAD-scale number is 20; some of the oil fuel in TVA tanks tested as high as 17. The utility has successfully used PRI-D, an additive from Houston-based Power Research Inc, to rejuvenate millions gallons of old oil and significantly reduce its PAD number.

Important to note is that up to 5% biodiesel can be added to petroleum diesel by refiners and distributors without reclassifying the fuel. Problem with storing such blended oils is that biodiesel is hydroscopic and decomposes faster than petroleum oil.

Also, the ultra-low-sulfur (15 ppm sulfur) diesel oil stocked by fuel depots today to meet EPA standards does not inhibit the growth of bacteria as well as the previous low- (500 ppm) and high-sulfur (5000 ppm) fuel oils. No matter; after Dec 1, 2014 all diesel fuel produced in, imported to, and burned in the US must be ULSD. Expect increased bacterial growth in your oil compared with historical levels.

Most ULSD comes from petroleum distillate, but at least one major oil company is said to be developing a synthetic product derived from natural gas. Regarding petroleum-based distillate, important to know is that the refining process used to remove sulfur reduces the aromatic content and density of the ULSD compared to conventional diesel oil. Lower heating value, about—1%—per unit of volume is the result.

However, the biggest user concern with ULSD may be the fuel's intrinsic lack of lubricity. Fuel oil provides its own "lubricant" when the sulfur it contains combines with nickel to form a low melting point alloy. Poor lubricity can lead to operational problems with critical components—pumps and flow dividers in particular.

Your options are to purchase and install replacement components designed for low-lubricity fuels or have your fuel supplier add lubricating agents to meet industry specs. The latter, if necessary, must be done at the fuel depot/terminal because pipelines usually will not transport ULSD containing additives. Biofuel in small proportions (typically 2% to 5%) also serves as a lubricant.

Raw ULSD has a lubricity of about 640 micrometers, well outside Siemens' GT limit of 460 µm (the higher the number, the less the lubricity); GE does not address lubricity in its fuel spec. You can verify the lubricity of oil received at your plant by having it tested using the high-frequency reciprocating rig described in ASTM D6079.

ASTM D975 is the lubricity standard for diesel fuel in the US and it specifies a limit of 520 µm; a comparable European standard specifies 460 µm. TVA has adopted the ASTM standard for oil delivered to its GT sites. However, in the company's experience, ULSD procured for its plants typically has a lubricity value of less than 400 µm and there is no need for further treatment before delivery.

Biodiesel for GTs

Interest in biodiesel grew during the days of high gas prices and even higher distillate prices. A few years ago, generous incentives and tax credits available to producers of biofuels, together with government pressure on producing electricity from renewables, had some power generators believing gas turbines powered by green oil might become reality. The availability of inexpensive gas might not be a deal-breaker for biofuels, but it certainly stretches out the commercial timeline.

Successful full-scale operational tests have been conducted on several industrial gas turbines burning biodiesel. This includes combustion of B100 (100% biofuel) at base load in a DLN-1- equipped 7EA at Duke Energy's Mill Creek site in South Carolina five years ago. The test was conducted on the 2002-vintage engine under the auspices of the OEM and EPRI.

This being a 7EA meeting, the author took the opportunity to review biofuel basics with the attendees. First the definition: Biodiesel refers to a non-petroleum-based diesel fuel consisting of long-chain esters. It typically is made by chemically reacting lipids (usually vegetable oil) and alcohol. It can be burned alone—as the Mill Creek and other tests have confirmed—or blended with conventional petroleum diesel.

Biodiesel can be obtained from a large variety of vegetable resources, but much land is required to produce those resources. For example, corn yields only about 18 gal of biodiesel from each acre in production; soybeans, 48; sunflowers, 102; peanuts, 113. Open-pond algae offers the greatest potential production of biodiesel per acre (10,000 gal), but there's no large scale production facility anywhere—yet.

Emissions from the combustion of pure biodiesel are significantly lower than those for conventional distillate: unburned hydrocarbons, 67% less; CO and particulate matter, nearly 50% less. However, NO_x is higher. When B20 (20% biodiesel/80% petroleum distillate) is burned, the numbers are -20% for unburned HC and -12% for particulate matter. NO_x is about the same.

Advantages of biodiesel compared to conventional No. 2 fuel oil are the following:

- Renewable fuel.
- "Soap" content of biodiesel keeps liquid fuel systems clean.
- "Carbon-neutral" emissions. CO_2 emissions are about half those released during the combustion of petroleum diesel, but this CO_2 originally was absorbed from the atmosphere during the growth phase of the vegetable stock. Thus proponents claim the fuel cycle is "carbon neutral." The same argument could be made for petroleum and coal, fuel production taking longer because of natural processes.
- Lower CO and particulate emissions.
- High lubricity.
- Pleasant exhaust smell (like French fries).

Disadvantages:

- Hygroscopic: absorbs water from the atmosphere.
- Increased potential for biological fouling.
- Storage time is limited because of hydroscopic action and relatively fast decomposition.
- Higher gel-point temperature.
- Higher pour-point temperature which is conducive to problems at low ambient temperatures.
- Contains about 10% less energy per unit of volume.
- Cleaning action of fuel can cause rapid filter blockage until system piping and components are cleansed of deposits, including varnish, from the previous fuel.
- Possibly higher NO_x emissions.
- Attacks and accelerates deterioration of some fuel system materials—such as rubber.

Fuel filtration

TVA's 7EA fleet, installed between 1999 and 2002, suffered several flow-divider failures relatively soon after commissioning. The primary causes: dirty fuel oil and system debris. Recall that flow dividers have small internal clearances and particles larger than 5 microns can create problems. The original flow dividers were rebuilt with beefier timing gears; later the OEM changed suppliers.

Logically, the filters were checked first. The OEM quoted the filter as "1 micron," but this fuel-system component was supplied by at least two vendors and filter performance was not consistent among the suppliers. Digging further, engineers found that units with flow-divider problems had filters manufactured from a synthetic material (not pleated paper) and the following characteristics:

- 1 micron, Beta 75.
- 15 micron, Beta 200.
- 19 micron, Beta 1000.

As is often said, the devil is in the details. Sure, these are 1-micron filters, but only at Beta 75. The B15=200 means that the filter will remove 99.5% of all particles 15 microns and larger (filter efficiency equals 1 minus 1 divided by the Beta ratio, or $1 - \frac{1}{200} = 0.995$). Thus many particles capable of damaging the flow divider can be found in fuel downstream of the filter.

The bottom line: It is impossible to directly compare filter micron ratings unless their micron-size Beta values are the same.

TVA has since standardized on Beta12>1000 filter elements for 7EA liquid fuel systems and Beta22>1000 for its 7B fleet. The older units have larger clearances in their flow dividers and fuel nozzles than the 7EAs and 7Fs. Installing fuel filters that are too fine for the service will develop a high delta P quickly and unnecessarily—particularly with cold fuel. Today, the utility changes oil filters every other year or when the pressure differential across the filter hits 15 psi.

Fuel oil heating

The OEM's fuel oil spec indicates a maximum allowable viscosity at the fuel nozzles of 10 centistokes (cSt) for light-off. A curve of No. 2 oil viscosity change with temperature indicates that this viscosity requirement is met with fuel oil at 24F (make your own curve by using a straight line through the points 12 cSt/15F and 8 cSt/35F). The relatively mild temperatures experienced at TVA plant locations means oil heating rarely is necessary for viscosity purposes.

However, filter blockage caused by waxing of fuel oil at low temperatures is of ongoing concern. Minimum pour point for TVA fuel is specified as 0F, easily met by ULSD. Cloud point, although not specified by the utility, typically is less than 20F. Low oil temperature caused by unavailable oil heaters was implicated in some unit trips (no 7EAs), but these may have been traceable to water in the fuel or high filter differential pressure that was exacerbated by cold oil.

All TVA gas turbines capable of burning distillate are equipped with GE's standard 480-V, 20-deg-F-rise fuel-oil heater. Some issues with thick, burned-on crud around the heating elements have been experienced and elements have failed because of overheating attributed to crud buildup, improper installation, and improper valve line-up. Relatively simple controls can prevent most failures.

For example, the heaters serving TVA's 7EAs are arranged to shut off when oil temperature hits 50F and circuitry prevents heater operation when there is no fuel flow to a unit.

However, no plan is foolproof. One site experienced a problem when electrical transients from auxiliary 480-V power switching caused a fuel heater's PLC controls to lose its programming. This caused the following chain of events:

- SCR control current output went to maximum.
- Heater operated at full power with no fuel flow.
- Severe overheating was brought to the attention of operators when smoke poured from the heater compartment.
- Fuel oil in the heater and adjacent piping reached several hundred degrees as evidenced by heater distortion and pipe discoloration.

Luckily this occurred during the site's manned hours and was discovered before a fire started. Keep in mind that the auto-ignition temperature of No. 2 oil is 494F, half that of natural gas and lower than gasoline (Sidebar).

Valves, off- and on-base

The eight 7EAs delivered to TVA in 1999 were supplied with fuel systems that included so-called OCV assemblies—combined stop/pressure-regulating valves arranged in off-base spool pieces. Many problems were experienced, particularly in cold weather, which the OEM attributed to "freezing." Plant personnel disagreed but heavily heat-traced and insulated all such assemblies, thereby making them "inaccessible." Extensive insulation re-work was needed after valve maintenance.

The OCVs were prone to fail open when fuel oil was first called for. Also, the needle-valve adjustment on their sensing lines was over-sensitive. When the needle valve was open too much, the OCVs hunted wildly, causing pressure swings; when closed too much, pressure feedback and regulating capability were lost. Only a small fraction of a turn on the needle valve separated the two extremes and setting at one flow meant the OCV didn't work at other oil flows.

The needle-valve setting was prone to being "bumped," especially during repeated insulation work. There always was some oscillation of regulated pressure caused by OCV instability when operating at load, regardless of the OCV setting. GE tried changing the internal orifice size within all OCV devices but that didn't help. Finally, the OEM admitted the OCV valves were inappropriate for the given application.

Also, the fuel-oil recirculation design arrangement for the spool pieces was counterproductive. Instead of recirculating back to the fuel-oil tank (ideally to the air space at the top

Fuel-oil safety facts, best practices

Users new to firing oil in gas turbines can benefit from information presented in the bullet points below. Some of the facts will likely surprise you.

- Auto-ignition temperature—the lowest temperature at which a substance will spontaneously combust without an external ignition source—of No. 2 fuel oil is 494F, which is lower than that for both gasoline (535F) and natural gas (more than 1000F). Note that the high-temperature alarm setting for the 7EA turbine compartment usually is about 300F.

  The low auto-ignition (AI) temperature of distillate is the reason that the purging requirements for oil-only and dual-fuel units are more stringent than those for gas-only units—particularly in combined-cycle applications.
- Flash point—the minimum temperature at which a liquid will vaporize to form an ignitable mixture in air—of No. 2 fuel oil is 143F. The flash point (FP) of gasoline is -45F. The takeaway: Diesel fuel has high FP/low AI temperatures and gasoline the opposite. This is why diesel is the fuel for reciprocating engines, which use only compression for ignition, while gasoline engines have spark plugs.
- Never try to fix a fuel-oil leak inside the turbine compartment with the unit operating or still very hot. People have burned to death doing this. A virtually invisible spray of fuel oil can drench clothing; excessive tightening of a fitting can make the leak worse or break the fitting.
- Ensure that false-start drain valves always open properly at low turbine speeds.
- Do not try to restart a machine without first allowing fuel oil to drain and purge adequately between starting attempts. Significant damage has been experienced when a false-start drain valve (FSDV) jammed closed and pooled fuel oil. Best practice: Install FSDVs with limit switches that must indicate open before the turbine can start.

of the tank), they recirculated to the discharge side of the fuel forwarding pumps. This did not help prevent hunting/oscillation of the regulating valves for steady operation.

GE tried replacing the OCVs with a combined stop/pressure-regulating valve arrangement from another manufacturer, but experience from a couple of tests at TVA, and experience elsewhere, showed the new set-up was only marginally better than the OCVs. Ultimately, the utility replaced the combined valve arrangement with separate pressure-regulating and stop valves. Important to point out is that TVA normally would not have installed off-base stop valves, which are not required by code, relying solely on the on-base stop valve. However, GE required it.

Purge, check, three-way valves. The first 16 7EAs installed at TVA, in 1999-2000, were supplied with fuel-oil and purge-air check valves located at the combustion cans (separate sets on primary and secondary systems). These were prone to the same issues that dogged the GE dual-fuel fleet for many years, including the following:

- Liquid-fuel check valves leaking in the reverse direction when operating on gas, thereby allowing combustion gases back into the fuel-oil system—sometimes all the way back to the storage tanks.
- Coking of fuel oil in the check valves and fuel nozzles, creating issues on gas operation.
- Leaking purge-air check valves, which allowed distillate to flow out of the purge-air tell-tale drain.

Later 7EA units, those installed by TVA in 2001-2002, were equipped with the three-way valve arrangement GE had just adopted. These proved problematic when operating on gas. Fuel oil trapped between the on-base stop valve and the three-way valve would heat and expand, causing the spool piece for the latter to move to an intermediate position. Symptoms of this at TVA were high CO readings on gas, caused by improper purge-air flow. GE subsequently retrofitted a complicated fuel-oil pressure-relief arrangement (automatically actuated when operating on gas) to accommodate this.

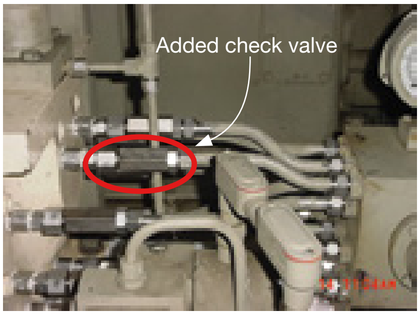
In the 1970s, GE's standard design practice (even for oil-only machines) was to have two fuel-oil check valves in series—one set located at the cans, another just downstream of the flow divider in the accessory compartment. This arrangement had proven reliable at TVA, so engineers thought to try it on a couple of check-valved 7EAs. An extra set of check valves, identical to those at the cans, was installed between the flow divider and the fuel-oil splitter valve (Fig 1). That mod solved the problem and it was implemented on all 16 engines equipped with check valves.

TVA suggested replacing the three-way valve/pressure-relief equipment on the later 7EAs with the dual-check-valve arrangement but the OEM nixed that idea. The units were operating under a long-term service agreement and the decision was GE's to make.

Bypass control valves were another sticking point. TVA's 7EAs all were supplied with two-way bypass valves with no valve position feedback, even for indication. All fuel-oil flow control was accomplished via flow-divider speed signals.

Early in the fleet's history there were extensive and serious problems associated with the liquid fuel system, especially when oil flows were high in cold weather. Issues included large oscillations in flow, causing piping in the accessory compartment to move enough to break welds and tear-up gear-type main oil pumps.

Some problems were attributed to strainer and filter blockage caused by improper flushing, failures of flow dividers, and poor fuel-forwarding stop valve and pressure-regulation control. While all these played a part, TVA engineers believed the main cause was an improperly specified bypass-valve design and control arrangement. Ultimately,



1. Additional check valves were installed immediately downstream of the flow divider, thereby eliminating the back-leakage of combustion gases and fuel-system coking associated with the previous single check-valve arrangement

2. Three-way bypass control valves reduced dramatically liquid-fuel flow oscillations experienced in cold weather at high unit loads

GE retrofitted all the units having three-way valves with three-way bypass control valves (Fig 2). The remaining check-valved 7EAs still have their original two-way bypass valves. Issues have been minimal because these units have not had to operate on fuel oil at high loads for many years.

How to reduce coking

An article in the CCJ mentioned using the atomizing-air booster blower to reduce coking in fuel nozzles by purging and cooling during shutdown on oil. TVA investigations showed that this originally was a GE idea, but never implemented at any plant. Trials were promising and the 7EA fleet was arranged for post-combustion air purge. Here are the details:

TVA units suffered coke buildup—most severe on primary fuel nozzles—when its dual-fuel units were repeatedly shut down on oil. Such buildup caused the units to drop out of premix steady state on the first gas start following several oil shutdowns. The OEM recommended transferring to gas during oil shutdowns to reduce coke build-up, which was effective. However, this often was not an option for TVA. When its units ran on oil, it usually was because gas was not available.

TVA got best results by keeping atomizing-air (AA) booster compressors running for nine hours after shutting down on fuel oil. Primary and secondary purge flow paths are open during this period and coke buildup is virtually eliminated. Fig 3 shows primary-nozzle coke accumulation after a four-hour oil run and oil shutdown; Fig 4 shows a primary nozzle after a four-hour oil run and oil shutdown with atomizing-air purge following shutdown.

As plant personnel gained experience with the technique they concluded that there was merit to running the booster compressor after all gas and oil shutdowns to prevent coking of oil that burps into the nozzles because of thermal platts

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3. Coke accumulation on a primary nozzle after a four-hour run on distillate and oil shutdown

4. Positive impact of atomizing air blower is in evidence after a four-hour run on distillate and oil shutdown

expansion while the unit is shut down. Keep in mind that the TVA 7EA fleet is not manned 24/7 but is available by remote start. Without the AA mod, the unit can be called on for load and fail to stay in premix steady state, thereby initiating an automatic shutdown attributed to high emissions.

Miscellany

- Loud, low-frequency noise (a nominal 25-Hz rumble) is common for water-injected gas turbines operating on fuel oil. The OEM has addressed this by installing orifices in the secondary fuel-oil lines so when the splitter valve is open, 60% of the oil flows to the primary nozzles, 40% to the secondary nozzles (normal fuel split is 50/50). TVA implemented this solution on several 7EAs as an experiment, but has not retrofitted the entire fleet because the noise is not viewed as a major concern.
- A problem associated with dual-fuel units using water injection for emissions control when firing distillate is backflow of combustion air via the water-injection check valves when operating on gas. Filling the water injection system with air creates problems when that system is next needed during oil firing. Issue was addressed by adding a large check valve immediately before the water-injection manifold in the turbine compartment (Fig 5).
- Fuel-pump clutch slippage has been experienced on several dual-fuel Frame 5s and 7Bs. Symptoms usually are load swings at high loads and fuel flows. Problem is easy to diagnose using a strobe light. Remove the clutch covers to gain access to the input and output shafts on each side of the pump clutch.

Slippage rarely is experienced at low loads, and because pump speed is constant, the strobe light frequency is adjusted to "freeze" the image with the unit operating at low load on distillate. As load increases and the clutch starts to slip (often intermittent) the pump shaft image loses its synchronization with the input shaft. Complete clutch replacement usually is the only remedy for this. CCJ

5. Large check valve was installed immediately ahead of the water-injection manifold to prevent air leaking by water-injection check valves from filling the water lines with air when burning gas

Identify, address potential weaknesses to mitigate cycling impacts

By Jonathan D Aurand, HRST Inc

1. Cracking on the inside wall of this elbow was caused by water quenching

2. Cracking initiated at long weld-neck flange connection also was attributed to excess water

3. Desuperheater overspray contributed to deformation of reheater tubes

Most combined-cycle plants were designed for base-load service. But must-take generation from renewable energy projects is forcing many gas-turbine assets to cycle and/or to follow load for a large portion of their fired hours. More cycles and faster ramps are known to adversely affect the health of your heat-recovery steam generator (HRSG). An engineering assessment is recommended to identify at-risk components and to suggest equipment mods and changes to O&M and inspection procedures to mitigate cycling impacts.

There are six primary areas to evaluate when conducting an HRSG cycling assessment. They are:

1. Desuperheater overspray. Most HRSGs were designed to use little or no spray water to control final steam temperature at full load. During startup and when operating at part load, conditions often require considerable spray water, reducing the temperature of the mixture to near saturation—particularly for the popular GE 7FA gas turbine. Desuperheater performance depends on the arrangement of heat-transfer surface, process conditions, and gas-turbine load.

Each desuperheater system is unique and must be evaluated based on the type of spray nozzle, lengths of straight pipe before and after the attemperator, and the ratio of spray to steam flows. If overspray occurs and remains unchecked, damage to interconnecting piping and downstream tube bundles will occur (Figs 1-3).

One way to reduce the demands placed on desuperheaters, especially those having to deal with the 1200F isotherm characteristic of 7FAs at part load, is to consider installation of an air attemperation system (access at www.ccj-online.com, "Protect HRSGs against damage at low loads," 1Q/2011). It uses fresh air to reduce the temperature of GT exhaust gas as it enters the HRSG (Fig 4).

2. Desuperheater control during startup can be problematic, particularly if overspray also is occurring. Some arrangements require repeated oscillation of flow to maintain a given final steam temperature set-point. This phenomenon, known as desuperheater hunting, can lead to thermal fatigue of the spray nozzle assembly in probe-style attemperators (Fig 5).

Some arrangements have poor placement of thermocouples for control purposes; others have improperly sized hardware for cyclic and part-load operation. Keep in mind that if cycling damage—such as plugging or breaking—occurs to desuperheater components, control of steam temperature borders on the impossible and subsequent damage is likely.

3. Drum-temperature ramp rates. Thick components joined together often heat and cool at different rates. The difference in temperature between the components creates a thermal gradient at the joint which imposes a thermal stress. In most HRSGs, the thickest joints are in the HP drum—such as the downcomer-to-shell connections (Fig 6). Evaporator risers and steam outlets also can be at-risk for thermal fatigue.

The thermal gradient across a given joint depends on the thicknesses of the components, connection type (refer back to p 46), weld details, and process conditions. Most of these parameters are difficult to change (specifically, weld details and process conditions), so operation must be addressed to maintain safe levels of thermal stress.

While most OEMs provide, and plants follow, startup curves based on pressure, the rate-of-change in saturation temperature really is the driving factor for thermal fatigue in steam-drum nozzle welds.

4. Economizer risks. Cycling economizers are a fatigue risk from thermal shock, which occurs when feedwater flow is initiated in a hot economizer. This can occur offline when drums are topped-off, as well as when feedwater begins to flow during a warm or hot start. In a panelized economizer, inlet tubes are put in tension as they try to contract when "cool" water enters the unit; subsequent passes in the same panel are still warm and restrain the headers (Fig 7).

Return-bend economizers may experience stress at the upper return bends as the inlet pass lifts off its supports. Upper return bends also may flatten when load is redistributed after the event. In addition, lower flow rates during startup and low-load operation mean lower economizer velocities, which may not be sufficient to overcome buoyant forces in down-flow passes and flow may stagnate or vapor lock in some down-flow tubes. This results in (1) thermal stress when flow increases and water begins moving through the tubes again, and (2) a decrease in thermal performance.

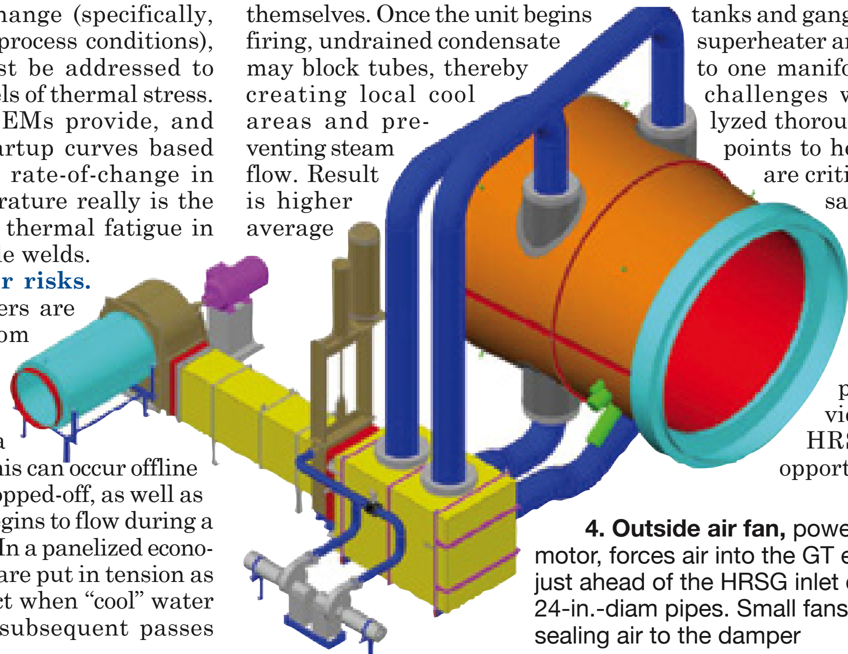
5. Superheater drainage. During the gas-turbine purge on a hot or warm start, superheaters become condensers as cooler air from the turbine is pushed across that heat-transfer surface. Steam inside the superheater panel cools until it reaches the saturation temperature and begins condensing.

Condensate collects in lower headers, interconnecting piping, and, if not drained properly, in the tubes themselves. Once the unit begins firing, undrained condensate may block tubes, thereby creating local cool areas and preventing steam flow. Result is higher average tube temperatures in the blocked tubes relative to neighboring tubes. Bowed tubes at the end of the headers (near sidewalls and center gas baffles) usually are caused by poor condensate management (Fig 8).

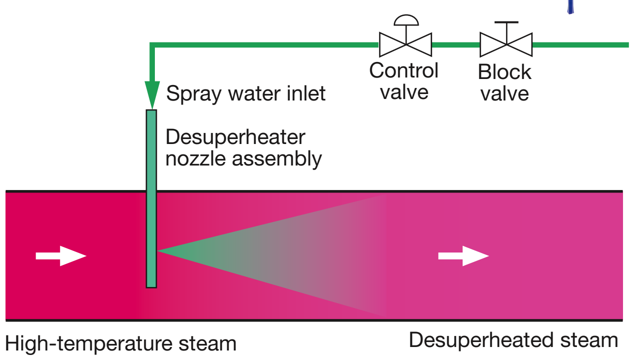
The drain system for each superheater and reheater panel should be evaluated for condensate production and drain capacity used. While a hot start produces the most condensate, a warm start may use a higher percentage of the drain capacity because less pressure is available to blow out the condensate.

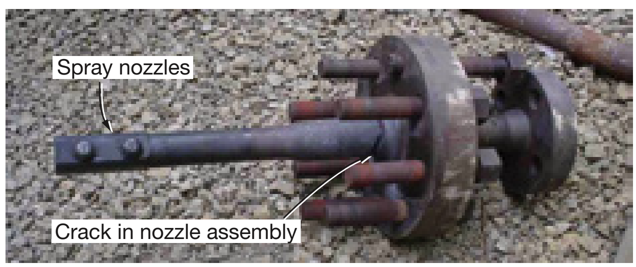
Additionally, elevated blowdown tanks and ganged drain manifolds (HP superheater and reheater discharging to one manifold) present additional challenges which should be analyzed thoroughly. Drain connection points to headers and piping also are critical, to prevent condensate from collecting in the downstream ends of superheater headers.

6. Control room philosophy. Observing a couple of starts from the control room provides solutions providers valuable insights. HRSG experts have the opportunity to follow opera-



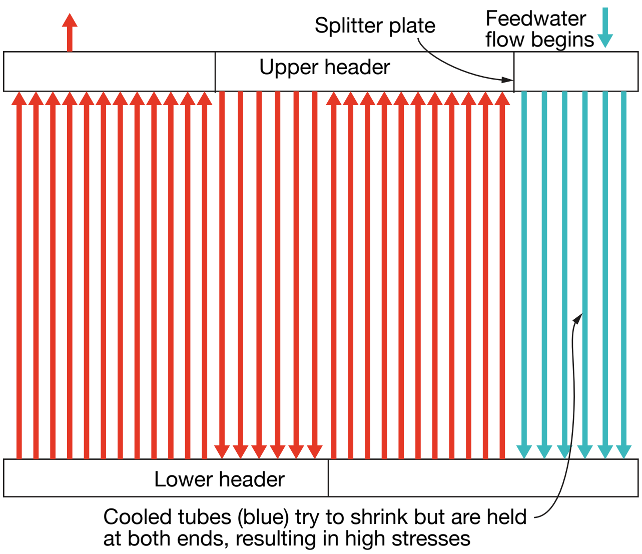
4. Outside air fan, powered by a 200-hp VFD motor, forces air into the GT exhaust-gas stream just ahead of the HRSG inlet duct via four nominal 24-in.-diam pipes. Small fans supply sealing air to the damper



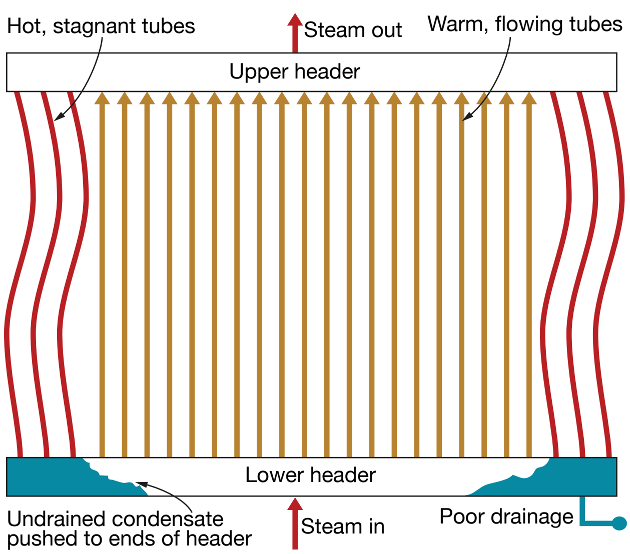


5. Spray nozzle assembly in probe-type desuperheater is susceptible to thermal fatigue damage

6. Cracking is visually evident at the downcomer-to-drum connection at left; close-up photo of the crack is at right



7. Cooled tubes try to shrink, but are held at both ends; high stresses result.



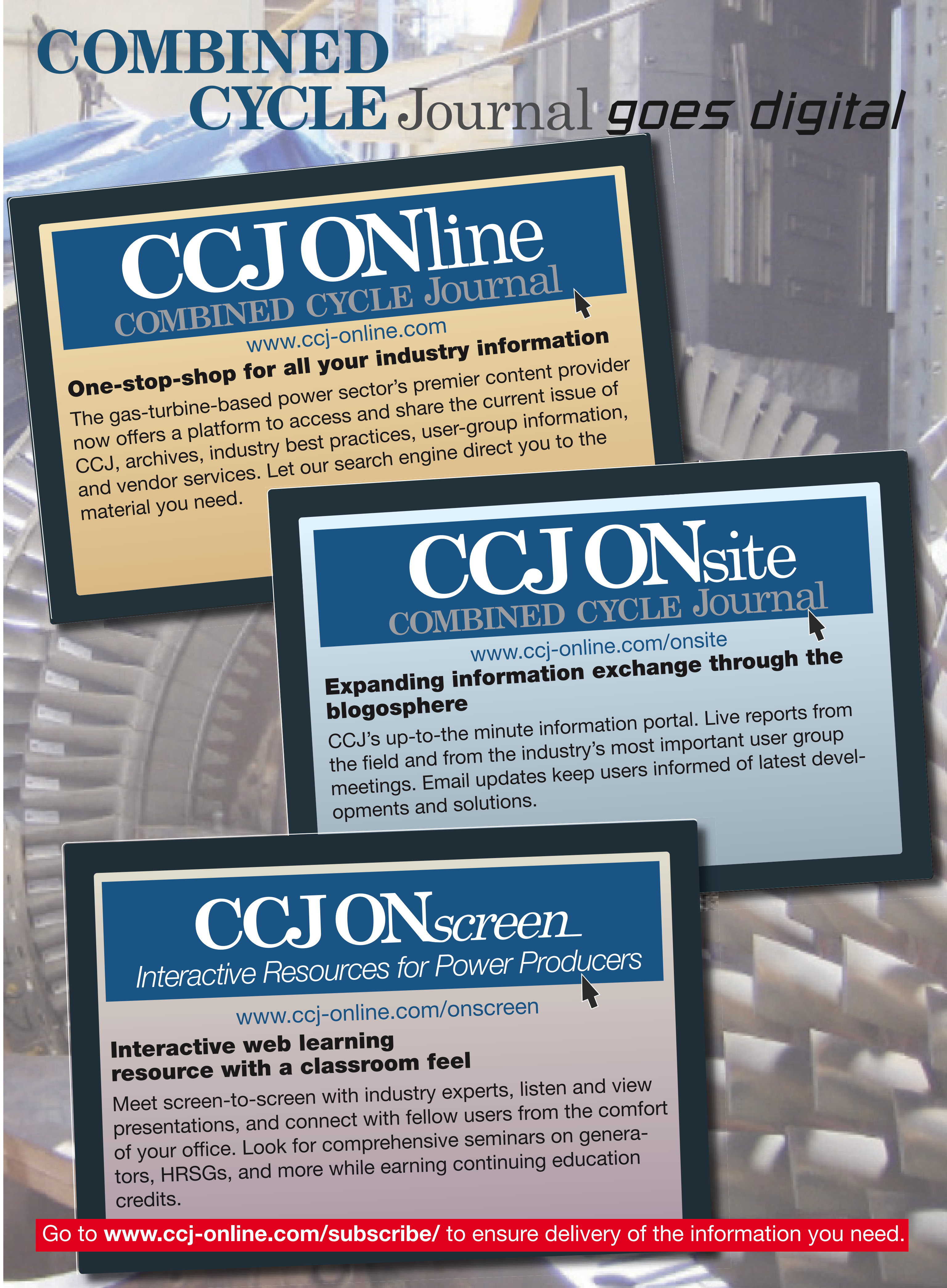
8. Poor drain system design allows condensate to block tubes in superheater and reheater panels

tions in action and question operational decisions as they are made.

Example: Some board operators mistakenly believe they are protecting their equipment by entering a final-steam-temperature set point that is lower than design. This actually increases the amount of water being sprayed by the interstage desuperheaters, thereby *increasing* fatigue risk.

Other examples can include sitting at a damaging low load for extended periods before turn-over to AGC (or dispatched load). Finally, there are tradeoffs among connected pieces of equipment. Maintaining steam-turbine stresses at acceptable levels is critical to reliable operation, but there is a tradeoff with HRSG component stresses. Control-room observations can illuminate such tradeoffs.

End notes. Performing a cycling evaluation of your HRSGs is prudent, as such an assessment helps to identify risk areas specific to your plant's arrangement and operation. These "watch" areas can be addressed through focused nondestructive examination, operational changes, and/or planned future capital improvements. Cycling a combined-cycle plant designed for base-load service without being fully aware of its idiosyncrasies can lead to forced outages and equipment damage that might have been avoided. CCJ



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Low gas prices dramatically shift facts on the ground

By **Jason Makansi,** Pearl Street Inc

1. Nipsco's Sugar Creek Generating Station, a 565-MW combined-cycle facility, has seen its capacity factor rise from less than 15% between 2002 and 2008 to close to 75% in 2012

Sugar Creek Generating Station

2012 Pacesetter Plant Award

In June, the Energy Information Administration reported that, for the first time since data collection began, megawatt-hours from gas-fired generation equaled that from coal-fired plants. That wouldn't have surprised the staff at Sugar Creek Generating Station (SCGS). In May, the 545-MW, gas-fired combined-cycle plant (Fig 1) logged an 86.7% net capacity factor (CF). It was the first month that the two gas turbine/generators, and the steam turbine/generator, operated every hour of the month.

Net CF for the first half of the year was 73.5%. To put that into perspective, the plant's net CF was under 15% (and as low as 3.2% one year) the first six years of the plant's existence, and under 50% in 2010 and 2011 (Sidebar).

But the latest natural-gas upsurge goes beyond EIA's national statistics. The coal-to-gas shift is dramatically altering the facts on the ground at power stations. SCGS experiences this more acutely perhaps because it is (1) located in West Terre Haute, Ind, the heart of coal country; (2) the only gas-fired asset owned by its parent, NiSource Inc, a holding company; and (3) competing for corporate resources with the utility's large coal-fired plants.

Movin' on up. . .

Facts on the ground have to change when your facility moves up quickly in the dispatch queue. SCGS faced a variety of "facts": Utility management wasn't familiar with combined-cycle plants, coal plant operation dominated the utility's culture, more operating hours meant fewer hours to do maintenance, and the staff is lean—even for a combined cycle.

Although the capacity factor was increasing, the plant is flexible, so it was called upon to cycle up and down in load, causing equipment stresses. The plant has a very favorable heat rate, but every bit of efficiency helps (and reduces fuel costs) as total operating hours rise. Fuel is typically 80-85% of the operating costs for a combined-cycle plant.

Like most combined cycles of this type and vintage, SCGS has contractual service agreements covering the gas and steam turbine/generators. Therefore,

Backgrounder on Sugar Creek

SCGS is a typical 2 × 1 combined-cycle facility with two 7FA gas turbine/generators and one D11 steam turbine/generator supplied by GE Energy, Atlanta, and heat-recovery steam generators (HRSGs) from Vogt Power International Inc, Louisville. Mirant Corp, the original owner (now a subsidiary of GenON Energy), commissioned the plant in 2002. LS Power acquired Sugar Creek in 2007 and sold it to NiSource the following year.

Flexibility, a hallmark of the facility, represents a big part of Sugar Creek's value to the owner. The plant can modulate on automatic generation control (AGC) through MISO at 15 MW/min over a typical load range of 330 to 489 MW. The plant can cycle down to 310 MW, but runs into CO emissions and heat-rate issues below that. Under 310 MW, gas-turbine combustion is unstable. Above 489 MW, HRSG duct burners can extract another 57 MW from the steam cycle, but the heat rate degrades to 7400 Btu/kWh.

plant staff could have the greatest impact by focusing on the HRSG and the balance of plant (BOP). To get focused on new operating and performance objectives, SCGS embarked on a program that applies state-of-the-art knowledge management tools and techniques anchored by reliability centered maintenance and operations (RCMO).

For its industry-leading role, SCGS/NiSource will receive the Combined Cycle Journal's 2012 Pacesetter Plant Award at the upcoming meeting of Combined Cycle Users Group in Orlando in October (www.ccusers.org).

RCMO closes gap

One way to think about the challenge faced by the plant is this: Three years ago, Sugar Creek personnel could spend 85% of the hours in a year making sure the plant ran as expected during the remaining 15 percent. Now those figures are almost reversed! And it's not like SCGS was a slouch in O&M. Its equivalent forced outage rate (EFOR) in 2010 was 0.5, reportedly fourth best in the country, when the plant's capacity factor was 31%—highly commendable for a staff of 16 operators, three managers, and one chemist.

Implementing an RCMO program (Fig 2) proved to be an ideal approach for SCGS' situation. For starters, RCMO was a 2011 performance initiative for NiSource's regulated utility Northern Indiana Public Service Co (Nipsco). Such a program would help SCGS quantify and justify the maintenance expenditures, identify operating and equipment design issues, and help staff conduct maintenance more efficiently within shorter intervals. Working with RCM consultant, MRG Inc, Southbury, Ct, gave SCGS and Nipsco the confidence to apply such a program to its lone combined-cycle facility.

"Before the RCMO implementation began in March 2011, the plant had well over 1000 planned maintenance tasks (PMs)," observes O&M Specialist Don Maffioli, "more like a coal plant." Pre-RCMO, the plant performed PMs based on the original equipment manufacturers' (OEM) guidelines. "Now we've gotten that number way down," Maffioli adds. "The PMs that remain have to pass the 'FARE' test—they have to be feasible, applicable, repeatable, and effective."

To keep the program manageable, SCGS applied off-the-shelf (OTS) failure mode and effects analysis (FMEA) templates that covered 80% of the equipment in the plant (many combined-cycle facilities have similar equipment). Only 20% represented custom-designed forms and screens. The program team still had to review the OTS templates and modify some of them, "but this was a real time-saver," says Maffioli.

Other RCM programs fail or break down because it is difficult, time consuming, and expensive to identify every possible failure mode on every piece of equipment in the plant. Plant Manager Darrell Boyll stresses that "we got buy-in from our operators to the RCMO program by having them directly involved in the FMEA process." This has enhanced the culture of performance improvement at the plant.

For example, operators have driven a startup optimization process, changed startup procedures, and, as a result, shaved a full hour off of a typical hot start. Considering that the plant experienced 161 starts in 2010, that's an important gain.

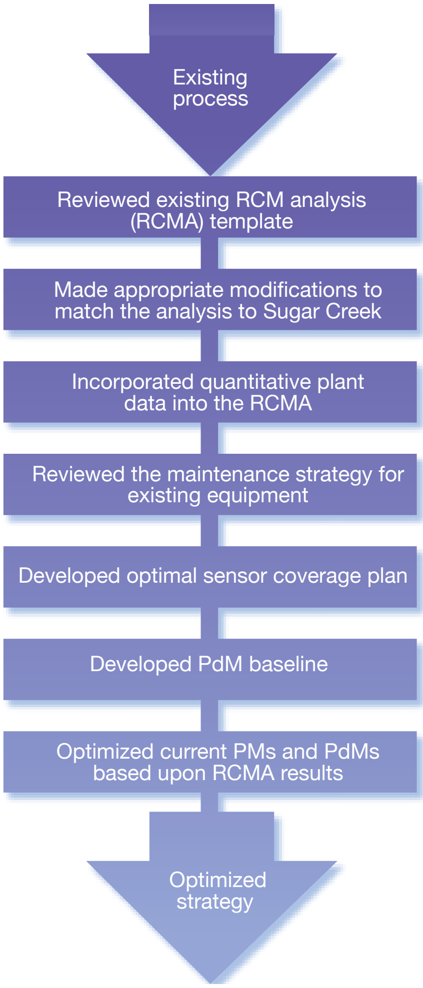
Each failure mode is ranked by a "risk prioritization number," derived from three variables graded from one to 10. The three variables are (1) the severity or impact of the failure, (2) the frequency of the failure and (3) the ability to detect the failure with monitoring that is currently in place. These three numbers are multiplied to arrive at the RPN. "This allows us to target all failures above a certain number, for example, to go after the worst actors first, get the low-hanging fruit, Boyll says."

For some equipment, any failure is unacceptable. One example at SCGS is the circulating water pumps (Fig 3). "Unlike other plants, we only have two 60% circ water pumps," notes Maffioli, "if we lose one, well, it's obvious, so we throw all the predictive maintenance and techniques we have at them."

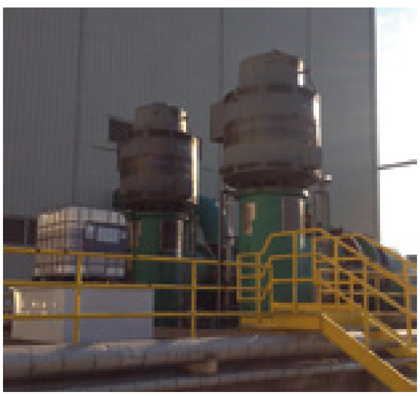
An important aspect of the program is that it is "living." Says Maffioli: "Any time we have an event that impairs our ability to meet our generation obligations, we submit a form called the Unit Trip/Load Loss Report. It contains detailed information about the trip and we narrow down the information to a failure mode, then review the FMEA for that equipment. If the failure mode has been identified, we determine why the control didn't mitigate it. If it is a new failure mode, we add it to the FMEA templates, along with mitigation strategies."

RCMO inspired upgrades

Several equipment deficiencies identified through RCMO, and subsequently corrected by the plant, have

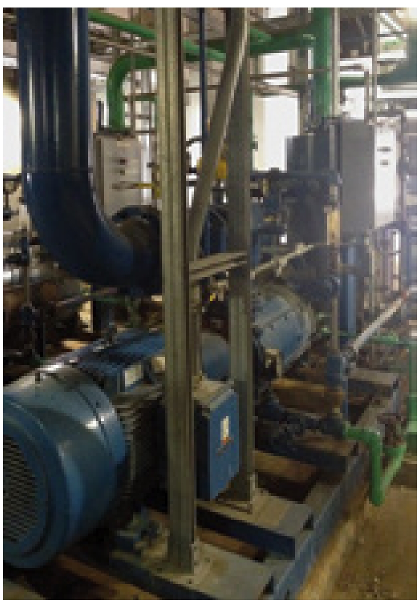


2. RCMO program, delivered by MRG Inc, proved to be the best way to meet the combined challenges of rising capacity factor, minimal staff, and need to provide business-case analytics to the maintenance budget. The most effective approach to understanding the proper level of support is knowing the needs of your physical assets. The output from this process is a verifiable, defensible maintenance strategy, which can then be quantified to justify accurate plant reliability improvements



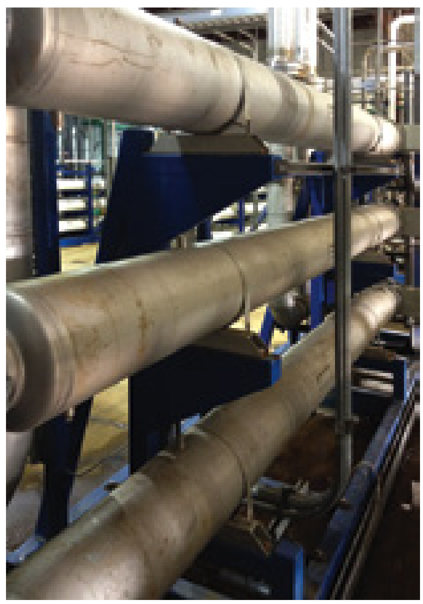
3. No failures are acceptable for two 60% circulating water pumps. All the predictive technology and techniques available are applied to them paid enormous dividends. Examples include:

- Modifying the vacuum-pump cooling system lowered the vacuum from 3.3 to 2.3 in. Hg abs, resulting in a 5-MW gain in output (Fig 4).
- Redesigning the high-pressure (HP) feedwater valves and feedwater minimum-flow valves reduced load on the feedwater pumps, lowering heat rate from 7000 Btu/kWh to under 6900 Btu/kWh (Fig 5). Reducing flow through the pumps by 500 gpm cut auxiliary power consumption by 1 MW.
- The FMEA review of the reverse-osmosis pumps at the water treatment unit revealed that a high-temperature shutoff switch, mentioned in the documentation, was not installed. These pumps were failing



4. Vacuum-pump cooling system was identified through the RCM program as deficient. Modifying it gained 5 MW of output

5. Replacing undersized actuators on the HP feedwater and feedwater minimum-flow valves allows the plant to consistently run at heat rates below 7000 Btu/kWh



6. High-temperature shutoff system was found missing from the RO pumps. Once the requisite sensors and switches were added, a history of failures was arrested at a rate of about one per year (Fig 6). Since the switches were added with the proper sensors, no failures have occurred.

- Cooling-tower gearboxes were failing at a rate of about one a year, incurring a $35,000 expense. The plant installed real-time bearing monitoring and displays vibration and temperature in the DCS.
- Review of the HP attemperator block valves indicated that the actuators were undersized. The plant ran with these valves open. Constantly blowing water into the steam had a relatively low performance impact when capacity factors were low. By installing more robust valves and increasing steam temperature, the plant has gained output.
- Evaporative coolers on the gas-turbine inlet could only be used during base-load operation. Under AGC, they tripped off. With modifications, the coolers now operate down to 71F at the inlet guide vanes (IGV), netting 3 MW of output per gas turbine.
- RCMO identified deficiencies in lubrication procedures. "Overgreasing is a major failure source within Nipsco," notes Maffioli. The plant conducted a pilot program with an ultrasonic greasing gun to mitigate the problem.

7. Sugar Creek ties into MISO (through Cinergy) via this substation, but it also has a separate substation connection to PJM, thus occupying a unique position from a grid reliability perspective for the Midwest

Rounds made meaningful

Complementing the RCMO program is an automated digital operator rounds process. "It's like a portable expert system," says Maffioli. Operators carry a mini-PC when they regularly check equipment. They answer questions and record data. When the PC is dropped back into its docking station, the data are automatically downloaded and trended. When the operators take a reading, they can see if it is outside established boundaries, and the PC will suggest actions to take.

"In the past," states Boyll, "operator rounds revolved around simple equipment checks, but they were qualitative in nature." The new AuditMatic® software (supplied by Form Automation Solutions Inc, Addison, Tex) has a simple point-and-click user interface and is designed to be set up and maintained by non-IT personnel. "It's an ideal tool for novice operators and even serves as a refresher for seasoned operators," says Boyll, "we're currently working on how to incorporate the data into the plant's historian."

Turbocharged RCM

The next phase of the program is to hire a full-time reliability engineer. But the plant intends to go beyond the traditional bounds of RCM and integrate predictive analytics. "We are planning a SmartSignal (now part of GE Intelligent Platforms) implementation, which will allow us to create a relational database by pulling and correlating data from the distributed control system (DCS) through the data historian."

In preparation for this, the plant has added sensors and controls to such equipment as the boiler feed pumps, RO pumps, cooling-tower gearboxes, selective catalytic reduction (SCR) unit, and vacuum pumps. The resulting analytics will help the plant identify root causes of failures and hidden failure modes critical to rounding out the FMEA templates for critical and non-critical components.

"One of the most fruitful areas for applying SmartSignal could be to the combustion dynamics in the gas turbines," says Boyll. "Avoiding one lean blowout pays for SmartSignal implementation." Because they are the only combined cycle in Nipsco's system, the economical approach is to buy the monthly subscription from the vendor rather than implement the software themselves.

Sittin' pretty

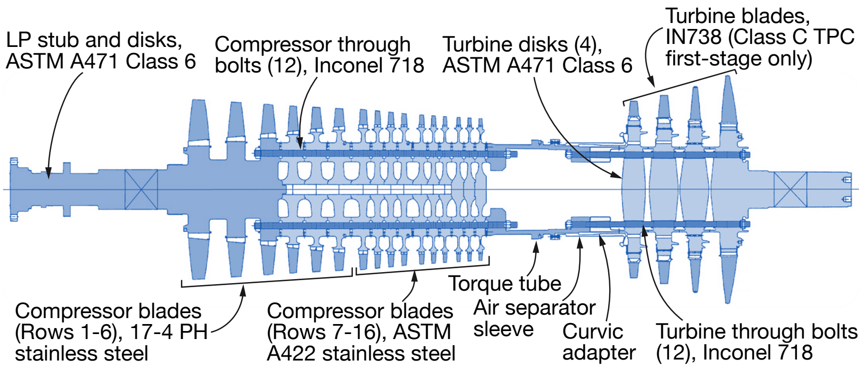
Reliability is generally jobs one, two, and three for most powerplants, especially those owned and operated by regulated utilities. But SCGS isn't just any plant when it comes to the grid. It is connected, through two separate substations and transformers, to both the Midwest Independent System Operator (MISO) and PJM Interconnection (Fig 7). Although SCGS is not a black-start plant, during a recent MISO blackout simulation exercise, it was the first plant called to connect up after the 345-kV ring was energized. Thus, reliability means more than profit and loss for the plant; it has a serious role to play in grid recovery. **CCJ**

Rotor disassembly basics, repair case histories

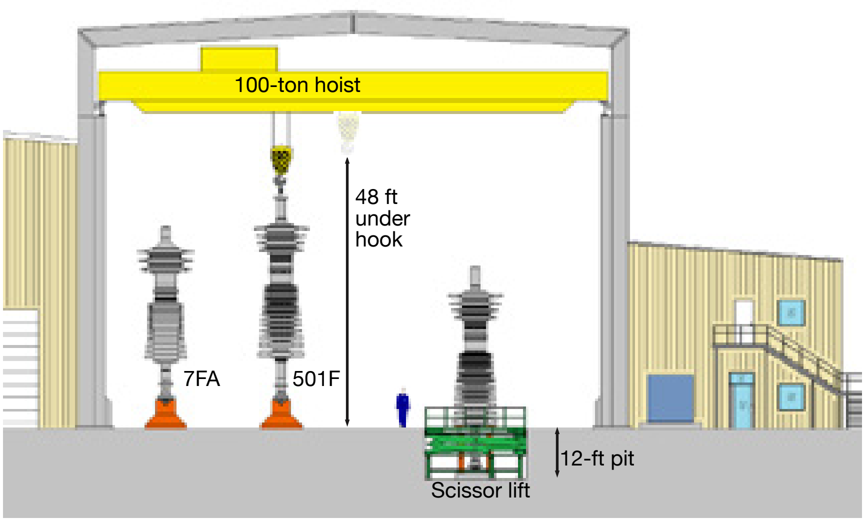
Rotors have become a top discussion topic at user-group meetings as gas turbines rapidly add hours and starts in these days of must-take renewables and low-price gas, stoking end-of-life concerns for critical rotating parts. Relatively few plant personnel have first-hand experience in rotor overhauls. Most have not had the opportunity to participate in unstacking, inspection, repair, restacking, and balancing activities. It is important to have perspective on these matters before you get involved with rotor work in a meaningful way.

Sulzer Turbo Services' Engineering Advisor Fernando Romero offered owner/operators attending the 2012 meeting of the 501F Users Group last February an instructive look at the dismantling of an 501FD2 rotor, inspection of its component parts, appropriate rotor repair methods, and reassembly. He told an audience of nearly 200 users at the Saddlebrook Resort in Tampa that his company had done work on a dozen such rotors, dismantled six, and found failed components on two of the six.

The first part of Romero's presentation was a valuable primer on the general design and configuration of the FD2 rotor, the dominant 501F-series model in service today. Important to note is that this machine differs dramatically from the 501FD4, Siemens Energy Inc's latest F-class production engine. The FD4 has three fewer compressor stages than the FD2 and variable guide vanes on three stages rather than one as on the FD2.



1. Materials map cross section of the 501FD2 rotor is a valuable training aid

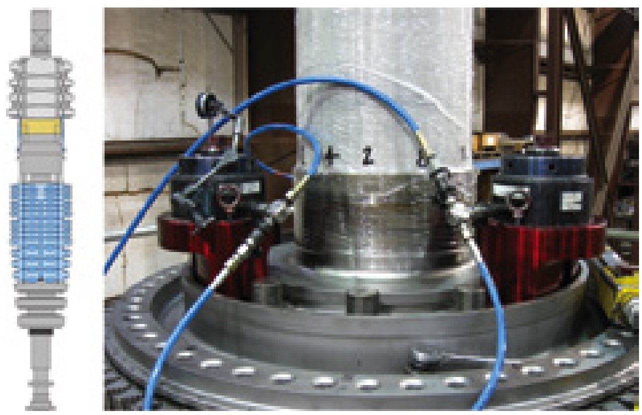


2. F-class rotors demand top-notch facilities for a proper overhaul. The 100-ton balance machine required is not shown in the sketch

A cross section of the 501FD2 rotor is presented in Fig 1. As the Fig 2 shows, it is a few feet longer than the competing 7FA engine from GE Energy. The FD2 is 32 ft long overall, divided among the compressor (18 ft), torque tube connecting compressor and turbine (4 ft), and the turbine (10 ft). Total weight of the bladed rotor is 54 tons. The machine is equipped with 1193 compressor blades and 334 turbine blades.

Unstacking begins after the rotor is moved to the pit by the bridge crane. First step is to relax the 10 turbine through bolts. This is done by stretching the bolts to (1) release the contact forces between adjacent disks and (2) to remove the nuts (Fig 3). However, before removing the nuts, technicians "mike" the bolts and record stretch data to determine if there's a problem caused by uneven tension or a cracked bolt. The R4, R3, R2, R1 wheels are then lifted off one at a time (Fig 4). Note that the Siemens turbine wheels do not have rabbet fits like the GE frames.

The component you see after removing the first-stage turbine wheel is the curvic clutch adapter. It sits on top of the torque tube. The air-separator sleeve slides over both and bolts to the flange on the torque tube. After the air-separator sleeve is removed (Fig 5), the compressor through bolts are



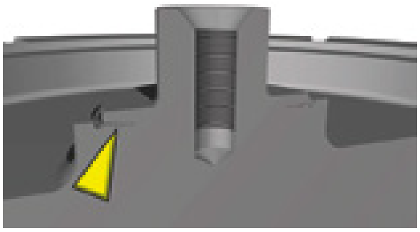
3. Turbine through bolts are relaxed using a five-step process

4. Turbine wheels are removed individually

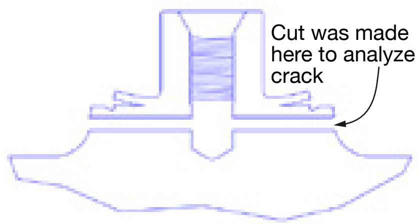
5. Air-separator sleeve is removed to access compressor through bolts

6. Dry ice is used to shrink the suction side of compressor wheels to prevent galling of rabbet surfaces

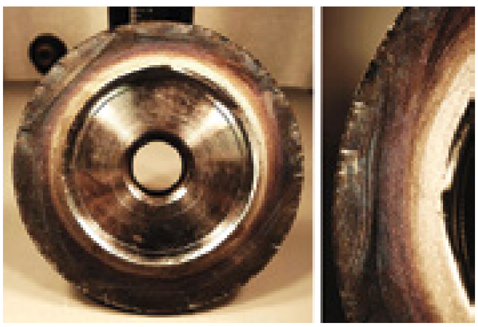
7. Pilot incorporated into the Stage 3 wheel on the LP stub has an internal thread, used for lifting



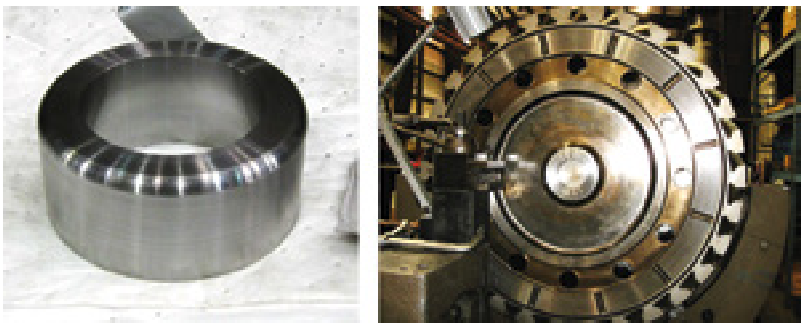
8. Crack encircles the pilot and is approximately 1 in. deep



9. Pilot was machined off the wheel to analyze the crack



10. Fracture surfaces showed evidence of heating, rubbing, and beach marks indicative of fatigue



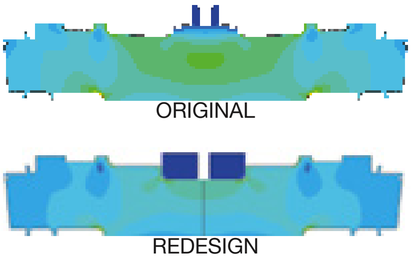
11. Insert was designed to take the place of the pilot, which is used only during the rotor assembly process, and installed in the wheel

relaxed, the torque tube is picked by the crane, and compressor disks are unstacked.

For compressor stages 5 through 16, dry ice is used to shrink the suction (male) sides of the wheels (Fig 6), which mesh with the discharge (female) sides of adjacent wheels, to free up the interference fit. This allows removal of each wheel in turn without galling rabbet surfaces. Stage 4 differs in that it has female fit-ups on both sides of the wheel and heat may be needed to remove it. The first three compressor stages are integral with the stub shaft.

Repair case histories

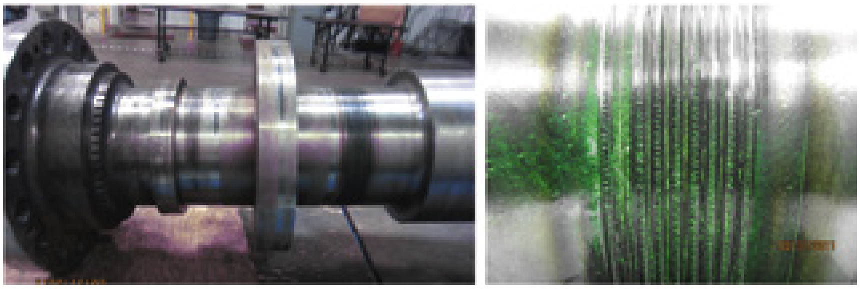
The first case history Romero discussed was a rotor that had been removed from operation because of high vibration resulting from a turbine blade failure. The aft end of the third compressor stage had high run-out



12. OEM design was evaluated to determine a baseline of stresses for the original hub at 3600 rpm (top). Stresses were calculated for various insert geometries until the best distribution was attained

The rotor showed no signs of intrinsic material defects that could have contributed to this failure, Romero said. However, corrosion pitting was linked to the dozens of initiation sites found at the OD of the part. An insert was designed to take the place of the pilot, which is only used for assembling the machine (Fig 11). The design was qualified by using finite element analysis (Fig 12).

Second case history. The rotor, taken out of service because of a lube-oil-system failure, did not exhibit abnormal vibration or run-outs. However, both the compressor and turbine



13. Compressor shaft end had deep rubs in oil seal areas. Repairs were made using the submerged-arc welding process, which deposited material automatically. Shaft was spun during the process to avoid distortion

14. Induction heating after repairs and a continuous rotation of the shaft help mitigate rotor distortion

and a 360-deg, 1-in.-deep crack was found at the third-stage pilot location (Figs 7, 8). The pilot, designed with an internal thread to facilitate lifting, was machined off to conduct a metallurgical analysis of the crack (Fig 9).

There were initiation points and beach marks all around the circumference. Fracture surfaces showed evidence of heating, rubbing, and beach marks indicative of fatigue (Fig 10). Corrosion pits were easy to see on the OD of the rabbet fit under an optical microscope. A scanning electron microscope revealed corrosion pits at the crack initiation sites.

shaft ends suffered heavy rubs in the oil-seal area. Plus, the pilot had failed completely and was hanging from the fourth-stage disc. Journal surfaces were repaired by submerged arc welding (Fig 13), then the shaft was stress-relieved and finish-machined (Fig 14).

Romero pointed out that the pilot "wasn't going anywhere" and had the rotor not been unstacked to facilitate the rub repair no one would have been the wiser. However, he said, you don't want to leave an untreated scar even if it's not an imminent threat. The same solution used in the first case history was applied in the second. CCJ

Engaged, effective leadership critical to well-being of plant staff, contractors

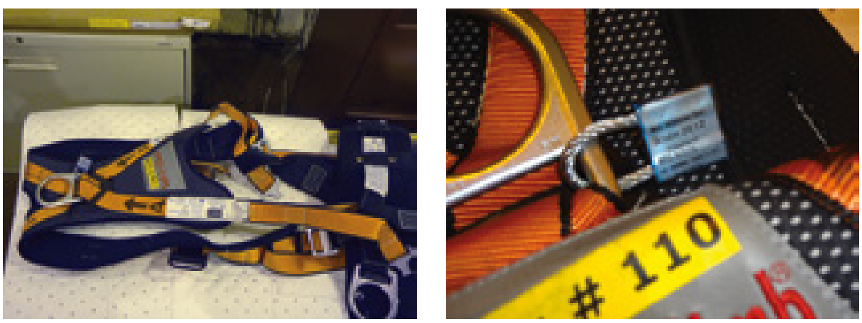
Safety has taken center stage in the electric power industry. It is now one of the top three discussion topics at virtually all user-group meetings serving gas-turbine (GT) owner/operators. Another way to gauge the industry's safety consciousness is to visit www.ccj-online.com and compare the number of safety and O&M entries in the COMBINED CYCLE Journal's Best Practices Awards program this year with those from five years ago. In 2008 there were more than twice as many entries in the O&M category than there were in safety; this year, there were one-quarter more safety entries than O&M.

The open discussion sessions at the annual HRSG User's Group meeting focus strictly on the technical aspects of heat-recovery steam generators, leaving safety off the main program. But with upwards of half the user attendees first-timers, many of whom are new to the industry and may not be aware of how just how seriously plant managers view safe work practices, Chairman Bob Anderson worked a primer on the subject into the Maintenance Workshop conducted the day before the "main event" last February 28-29 at the Hilton Americas in Houston, Tex.

Anderson, a principal at Florida-based Competitive Power Resources Corp and former plant manager at Progress Energy steam and combined-cycle plants, was the right person to handle this assignment. His goal was "awareness," not to conduct a safety course. He told the editors he would have been surprised if industry veterans didn't know almost all of the safety dos and don'ts included in his presentation, "Identifying—and Avoiding—Combined-Cycle Hazards," but believed his common-sense approach to safety would be of value to the "recruits."

Developing a safety culture

Anderson began by telling the group of about a hundred users that building and nurturing a safety culture is a prerequisite for operating and maintaining a safe plant. He defined "safety culture" as a constant commitment to safety that permeates the entire organization. But while this is



Safety equipment should be inspected by a qualified plant employee before each use, regardless of vendor certifications. Each piece of gear should have a permanent tag/number to assure meaningful record-keeping. *Astoria Gas Turbines*

Mobile filter cart and piping modifications allow ground level access to circ-water-pump motor lube sump making hazard-free a job that had been dangerous. *Allegheny Energy Units 3, 4, 5*

Inlet filter house floor, originally made of steel plate, was replaced with steel deck grading to prevent snow drifting in winter which blocked air flow and to eliminate a slip hazard. *Beatrice Power Station*

Ammonia-tank leak-suppression system protects plant personnel and neighbors. Water spray system, which has 34 nozzles configured on six lines surrounding the tank, was designed to NFPA

an essential step, he continued, it is only one of several.

Another essential step: Identify the real-world hazards present in the plant and implement practical procedures to avoid them. Anderson said that based on his experience, the specifics of these procedures are best managed at the plant level, not by safety professionals at headquarters. This is particularly challenging at thinly staffed combined-cycle plants, he added, where the onsite safety leader usually has multiple responsibilities.

Other safety challenges at combined-cycle plants may include inexperienced personnel and a heavy reliance on contractors. Many technicians and operators come from other industries and are generally unfamiliar with powerplant operations, Anderson said. Plus, with the typical combined-cycle complement numbering two dozen or fewer personnel, you don't have the relevant expertise on staff to handle anything much beyond routine maintenance.

Odds are contractors will be unfamiliar with your plant and its safety best practices and may require comprehensive indoctrination for certain assignments, as well as continuous oversight by plant employees.

Categories of hazards

To discuss the specific hazards found in combined-cycle plants in an organized manner, Anderson sorted them into these five categories:

- Hazards created by "merely moving around."
- Uncontrolled release of fluids.
- Controlled release of fluids.
- Hazards during normal plant configurations.
- Hazards during abnormal plant configurations.

Safety shed protects personnel against severe weather. *Jasper Generating Station*

"Merely moving around" hazards include trips, falls, burns, chemical inhalation, eye contamination, hearing damage, etc. They are the easiest hazards to avoid, through conscientious use of hard hats, eye and ear protection, respiratory gear, proper footwear, gloves, good housekeeping, good lighting, etc. Unfortunately, Anderson noted, these are the hazards that also are the easiest to overlook because you walk by them daily and become complacent about the dangers they pose.

Because such hazards often are hard for site personnel to identify because "everything looks normal," plant managers may use the buddy system for auditing. This is how it works: Plant A sends three or four of its most safety-conscious employees to Plant B—and vice versa—to conduct an audit with a "fresh eye." Sharing of ideas and experiences is especially productive.

The hazard in this first category with, perhaps, the most lethal potential is the confined space. Moving into such areas as HRSG casings, steam drums, condenser steam side, etc, before they are properly vetted can lead to serious injury or death. In particular, the confined-space atmosphere must be checked to assure sufficient oxygen to support life and the absence of poisonous/explosive gases.

The photos distributed throughout this article illustrate ways plants are mitigating "merely moving around" hazards. The generating plants identified received Best Practices Awards within the last three years for sharing their ideas with the global community of gas-turbine users. You can access many more safety best practices by using the search function available at www.ccj-online.com.

Uncontrolled release of fluids. Combined-cycle plants require the movement of large quantities of combustion air, steam, exhaust gas, fuel gas, oil, and water. Most often, these fluids contain high levels of energy because of their mass flow rates, pressures, and/or temperatures. Thus their uncontrolled release presents

Permanent platform provides safe access to gas-turbine igniters. *Granite Ridge Energy*

Safety permit stations are strategically located on the deck plates. They are easily accessible and highly visible. *Granite Ridge Energy*

Location of emergency showers is clearly identified with decals on walkways. Alarm sounds when shower is in use. *Mint Farm Generating Station*

a significant safety hazard to onsite personnel.

Anderson said the most common source of uncontrolled fluid release is a pressure-boundary breach caused by material failure. Typically, the fluid release is sudden, violent, noisy, and accompanied by substantial movement of equipment and structural components.

Those in the immediate area of an uncontrolled release, he continued, can be injured or killed by asphyxiation, burning, scalding, falling, or being struck by flying debris. Injuries also have occurred while the startled worker is franticly trying to escape the area.

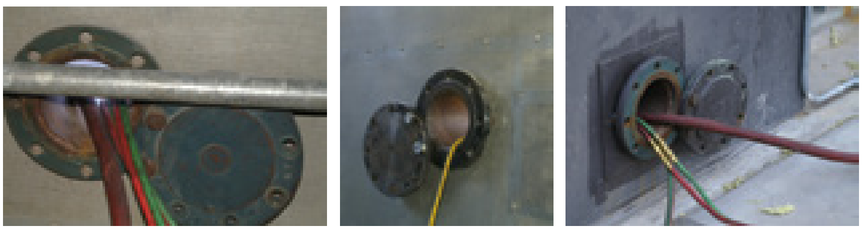
Shifting into high gear, Anderson appeared to have the group's undivided attention. "Although we cannot precisely predict *when* an uncontrolled energy release might occur," he said, "we can precisely predict *where*. As plant leaders we need to identify the specific locations in our facilities that are most vulnerable and take steps to minimize personnel risk. All employees and contractors should be made aware of these areas so they can avoid them when possible and be mindful of a safe means of egress whenever they need to work there."

High-energy steam piping was one of the areas of concern mentioned by the former plant manager. He had a special respect for joints where dissimilar metals or P91 materials are welded, noting that both the P91 material and its welding are intolerant of any deviation from proper thermal treatment. If you see steam or condensate escaping from a pipe's lagging, Anderson said, "Leave the area and report your finding to the control room immediately." An immediate precautionary shutdown is in order. Do not remove insulation to investigate the leak while the pipe is still pressurized.

The speaker mentioned several other places where uncontrolled releases of steam might occur in quick succession. When he got to steam-drum manway gaskets, he paused. Many plants continue to suffer gasket failures, Anderson noted, and continue to experiment with different solutions. "But this is a serious safety problem and no place for a trial-and-error approach. The manway door and the gasket, together, comprise an engineered system that must be properly designed, operated, and maintained according to the OEM's specifications."

Steam is not the only dangerous fluid, Anderson said, shifting gears. Uncontrolled releases of hot gases also present serious hazards, he said. Specific locations where vigilance is necessary include the following:

- GT exhaust duct/HRSG expansion joints, which protect against the release of exhaust gas at temperatures up to 1200F.
- Duct penetration seals.



Penetrations on enclosures eliminate the need to run lines, cords, and leads through doorways. *Walter M Higgins Generating Station*

Highly visible numbers (18 × 18 in.) at all key entrances to plant save time in directing emergency response units to the proper location. The numbers should be high enough off the ground that the line of sight cannot be blocked by deliveries, parked vehicles, etc. *Granite Ridge Energy*

- Flanges, valves, fittings, and heat exchangers—especially in the fuel gas system, where temperatures may be 350F and pressures 700 psig.
- Gas-turbine flanges, expansion joints, valves, and fittings. Example: Compressor bleed air may reach temperatures up to about 700F.
- Exhaust stack drains, which could release flue gas at up to about 300F during normal operation, higher temperatures during startup.

Don't forget, too, the speaker went on, that uncontrolled releases of seemingly harmless fluids like compressed air and water can cause injury. Examples: Debris sent airborne by the sudden release of a fluid, the whipping action of an unsecured compressed-air hose, flashing of pressurized high-temperature water when the pressure boundary is compromised, etc.

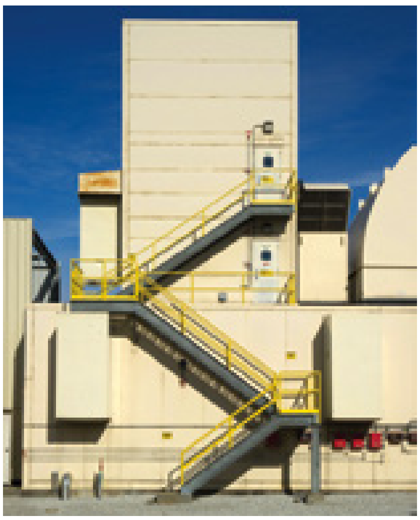
Controlled releases of fluids also are of concern. They may be sudden and unanticipated, as with the lifting of safety-relief valves; or planned, as with the opening of vents and drains. Either can pose a safety hazard because the actual point of fluid release typically is far from the actual valve or vent.

A contractor may be standing near the safety-relief discharge, unaware that a steam-pressure excursion is about to cause an automatic lifting of that valve. Or a plant operator manually opening vent valves may not know that a mechanic happens to be tackling an unrelated maintenance job, right near that vent's discharge point.

Safety-relief valves pose yet another concern. They often are surrounded by a large cloud of steam, hot water, and debris because of the inherent gaps in the valve upper body, discharge nozzle, and vent/stack connection. If such a cloud envelops a nearby walkway, a normal egress route might be blocked.

As with an uncontrolled release of fluids discussed previously, you can reduce the risks associated with controlled releases by identifying the specific locations in your plant that are most vulnerable and making them well known to staff and contractor personnel.

Normal plant configurations. Plant systems typically are lined-



Steps and landings replaced the standard ladder system to facilitate safe access to gas turbine's combustor section. *Rokeby Generating Station*

Roof hatch over bearing tunnel facilitates confined-space rescue. *Edward W Clark Generating Station*

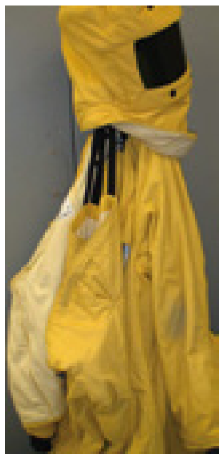
up in one of a handful of normal, well-understood configurations. This facilitates such plant operations as GT ignition and loading, steam system warm-up and loading, plant shutdown, and overnight layup. As the plant O&M team gains experience, it naturally becomes competent and comfortable with the normal configurations and procedures.

However, Anderson said, as a person with supervisory responsibilities, you must ensure that the staff's comfort zone does not expand into complacency because there are many hazards associated with a normal plant configuration.

For example, many components are energized automatically by the control system or remotely by a control-room operator challenged by time constraints and revenue goals. Although intentional, the sudden actuation of valves, pumps, turbine shafts, and compressors can injure personnel near the equipment who are caught unaware. Components may actuate unintentionally as well because of equipment malfunction or operator error.

Both intentional and unintentional events often produce startlingly loud noise, which can cause permanent hearing loss to an unprotected worker or plant visitor. Hazards attributed to equipment failure or operator error include:

- Water hammer, which can initiate pipe or structure movement, sudden noise, flying or falling debris, release of fluids, etc.
- Gas-path explosions caused by inadequate engine purge also is characterized by sudden noise. Other hazards include the release of exhaust gas, distortion of ductwork and structural members, expansion-joint and penetration-seal failures, flying debris.
- Metal-clad switchgear failure is characterized by sudden noise, arc burn, flying molten metal, flying debris. Personnel should minimize the time they spend near this equipment, Anderson warned, and never attempt to close the switchgear on a load using the local controls on the front of the breaker enclosure.



Flash suit protects plant personnel against arc-flash hazards. *Gateway Generating Station*

Abnormal configurations. A powerplant typically is most hazardous when plant systems or personnel are in an abnormal configuration. During these times, the valve and equipment line-ups are generally unfamiliar to the plant staff, and also extremely complicated—creating conditions ripe for mishap—such as chemical releases, environmental spills, etc.

A hazard of abnormal plant configurations is the need to sometimes connect piping and equipment rated for different pressures. Equipment failure or inappropriate operation of these interconnections can quickly cause over-pressurization and catastrophic failure of the lower-pressure system. Examples here include auxiliary steam ties between units and ties among high-, intermediate-, and low-pressure boiler drains.

Anderson closed with several examples of abnormal plant configurations that have serious safety implications, requiring careful consideration and special procedures to prevent injury to plant and/or contractor personnel. They are:

- HRSG gas-path inspection with a nitrogen blanket on the steam side. Rigorous confined-space (gas side) air monitoring is important because an unknown tube leak could allow nitrogen to fill the lower gas-path spaces.
- Unusual rigging and lifting during major outages demands that your staff and contractor personnel take exclusion barricades seriously. Rotors have been known to drop. Also, before you install exclusion barricades, make sure all workers inside the barricaded area are escorted outside the barricades. Yes, there have been instances where people have been "barricaded in."
- Chemical cleaning of an HRSG demands a special safety review. With so much temporary piping, valves, heaters, and pumps, there's a significant risk of hot chemical leaks or spills.
- Repairing or replacing piping system components and welds opens a Pandora's box of safety issues, including high elevation or difficult access, additional risk of fire, additional risk of trips and falls because of cables and hoses for burning, welding, heat treating, etc.
- Reports of extreme weather conditions must always be taken seriously. High winds, rain or snow, ice, and extreme temperatures greatly increase the risks of slips and falls, risks from flying debris, risks of extreme worker fatigue, etc.

Leaving the podium, Anderson reminded the group that safety is a never-ending battle fought day-in and day-out. Ultimately, he said, it is your engaged and effective leadership that assures the well-being of all persons inside the plant fence, not corporate programs, catchy slogans, or cute posters hanging in the break room. **CCJ**

7F USERS GROUP

We've Moved!

New website and forum at www.7Fusers.org

Your Steering Committee is developing a better website to serve both 7F users and their vendor business partners. Much work has been done already. We have improved the "look and feel" and are continually adding content that will bring value to owners and operators. Use of the website and forum are free and they are managed hands-on by your Steering Committee. Please visit www.7Fusers.org to see the improvements made. And while you are logged on, please re-register to be sure all the information we have for you is current.

Same Steering Committee

Back row (l to r): Eugene Szpynda, NYPA; Jim Sellers, Entegra Power Group; Richard Clark, Southern California Edison; Ed Fuselier (Vice Chairman), Direct Energy; Jeff Gillis, ExxonMobil Chemical; Ken Gross, Con Edison. *Front row:* David Such, Xcel Energy; Dan Giel, Progress Energy; Sam Graham (Chairman), Tenaska; Ben Meissner, Progress Energy; Bob Holm, OxyChem; Paul White, Dominion Resources; Peter So (Treasurer), Calpine. *Camera shy:* Tom Berry, Tampa Electric; Art Hamilton, Calpine

Same organization planning the annual conferences

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NAES plants land four

Powerplants managed by NAES Corp, Issaquah, Wash, earned the lion's share of the hardwood presented by the editors at the Best Practices Awards luncheon last April. The annual event, hosted by the Combustion Turbine Operations Technical Forum (CTOTF™) and organized by Wickey Elmo of North Carolina-based Goose Creek Systems Inc, recognizes the achievements of station and headquarters personnel in improving the safety and performance of generating facilities powered by gas turbines.

NAES, perhaps the world's largest third-party operator of powerplants, had its name on 10 of the awards presented, including four of the six Best of the Best plaques. Recall that there are two levels of awards to recognize achievements at individual plants: Best Practices and the Best of the Best, as determined by the scores of judges selected from the CTOTF Leadership Committee.

A dozen NAES personnel responsible for their plants' achievements, as well as John Brewster, president and CEO, were on hand for the awards ceremony. Brewster took to the podium at the luncheon to speak to the attendees regarding the importance of information exchange and programs like the Best Practices Awards throughout the industry.

Seven judges reviewed entries from more than three-dozen finalists this year, evaluating the submittals based on real and measurable achieved business value, complexity of the issue, operations staff involvement, degree of coordination across plant and headquarters engineering and O&M groups, and duration of impact.

NAES's John Brewster

The judges included management personnel responsible for fleet-wide O&M planning and execution, plant managers, and aero and frame experts with more than two centuries of applicable experience.

The awards program was launched eight years ago by the COMBINED CYCLE Journal, in association with CTOTF, the nation's oldest user group serving gas–turbine owner/operators.

Think of the inscriptions on the Best Practices Awards plaques that follow as an index to proven ideas that you can implement to improve plant operations and better protect personnel. When you identify a promising idea, you can get more detail simply by accessing www.ccj-online.com and clicking on the "Best Practices" tab.

Want still more ideas? Click the "Archives" button near the top of CCJ Online home page and click on 1Q issues back to 2005.

Sometimes the information disseminated in the magazine is not sufficient for your needs. Mike Elmo of Goose Creek Systems has posted PowerPoint files on the CTOTF website with additional details of Best of the Best ideas from 2010 to 2012. These presentations were made before the CTOTF membership during special sessions at the last three Spring Turbine Forums.

Access to the slides (users only!) is through www.ctotf.org. Just log on to the site and proceed to the Internet Bulletin Board Communications Service (IBBCS). Scroll down to the Presentation Library and locate the PowerPoint you're looking for. Site registration is open to all GT owner/operators; just follow the directions on the home page if you don't already have access. CCJ

2012 Best Practices Awards Sponsors

- Braden Manufacturing LLC
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- Emerson Process Management Power & Water Solutions
- Goose Creek Systems Inc
- Pratt & Whitney Power Systems
- Sulzer Turbo Services
- Wood Group Gas Turbine Services.

Submit your entries today for the 2013 Best Practices Awards

One way to get management's attention long enough to appreciate the contributions you and your co-workers are making on a daily basis is to win an industry award. The Best Practices Awards program conducted by the COMBINED CYCLE Journal, and endorsed by the Combustion Turbine Operations Technical Forum (CTOTF™), recognizes ideas implemented by plant personnel to increase reliability/availability, improve efficiency, reduce emissions, minimize accidents, etc. Such performance improvements are important to every owner and its management team.

To enter the 2013 Best Practices Awards competition, access the requirements, rules, and online entry form at www.ccj-online.com/best-practices. The program supports work done in gas-turbine-powered combined-cycle, cogeneration, and peaking plants larger than 5 MW. There are eight awards categories: Management, Environmental Stewardship, Design, O&M Business, O&M Major Equipment, O&M Balance of Plant, Safety Equipment & Systems, and Safety Procedures & Administration.

Your entry should take no more than about two hours to prepare and e-mail to scott@ccj-online.com. Photos and diagrams explaining the work done, plus a picture of your plant, are encouraged. The deadline is Dec 31, 2012, but don't wait: Prepare the entry today, while the accomplishments are fresh in your mind.

Judging will be by a panel of experts from the CTOTF Leadership Committee.

Best of the Best awards

Best of the Best recipients

O&M Balance of Plant

Termoemcali

Installation of a CO_2 neutralization system for the plant's demineralized water treatment facility reduced the site's dependency on sulfuric acid by 50%, thereby improving operational reliability, creating a safer work environment, and avoiding potential compliance penalties (Fig 1).

O&M Business

Green Country Energy

Institution and development of an internal compliance team, comprised of plant personnel, ensures that NERC reliability standards are observed and the facility is primed for compliance audits (Fig 2).

Environmental Stewardship

Green Country Energy

Installation of an outfall wastewater retention tank to effectively treat wastewater from plant processes significantly improves discharge operations and allows the plant to reliably maintain permit compliance.

Safety Equipment & Systems

Hopewell Cogeneration

Development and implementation of a system of tie-off access points ensures personnel safety when removing the gas-turbine enclosure during maintenance outages (Fig 3).

Safety Procedures & Administration

Hopewell Cogeneration

Plant personnel have computerized emergency action plans so operators can quickly and easily access comprehensive procedures and instructions for proper management of any emergency situation.

Design

Faribault Energy Park

Freeze-related operational challenges from makeshift water treatment trailers motivated plant staff to design, procure, and install a permanent RO system with ultrafiltration, resulting in water quality improvements and increased personnel safety (Fig 4).

Best Practices recipients

O&M Balance of Plant

Ceredo Generating Station

The plant utilizes a repeater-based radio system to its fullest extent to ensure personnel safety, site security, and operational reliability.

Greater Toronto Airports Authority (GTAA) Cogen Complex

Installation of a small bypass motor and VFD for the circulating water

1. Dave Ehler

2. Paul Peterson, Linne Rollins, Rick Shackelford

3. Dustin Tippins, Chuck Barnes

4. Bob Burchfield

5. Craig Rock, John Souther

6. Benjamin Privett

7. Lynn Thompson, Paul Park

8. Tom Burger

9. Steven Smith

10. Donnie Scott

11. Hank Tripp

12. Jay Slakes

13. Chad Darling

14. T C Austin

system allows the plant to maintain proper water chemistry when it is not in operation, yielding significant energy savings (Fig 5).

McClain Power Plant

Installation of VFDs for cooling-tower fans enables flexible operation thereby increasing system performance and reducing both energy use and costs (Fig 6).

North Pole Expansion Plant

Plant personnel implemented control logic changes to eliminate unnecessary electric load drawn by the standby boiler feedwater pump, reducing energy consumption at the site by 11,000 kWh per month (Fig 7).

Union Power Station

Installation of a sodium hypochlorite system to treat raw water for plant processes improved operations, eliminated the use of chlorine for biological content control, and reduced chemical costs (Fig 8).

O&M Business

Osprey Energy Center

Plant personnel implemented an active HRSG performance monitoring program, utilizing thermal imaging, enhanced piping inspection procedures, and drain valve monitoring to improve heat rate and reduce the forced outage rate (Fig 9).

Tenaska Central Alabama Generating Station

Modifications to the plant's generator control system logic and interface graphics ensure continuous compliance with NERC requirements for power system stabilizer and automatic voltage regulator operation.

Tenaska Virginia Generating Station

The plant implemented control logic to the DCS that notifies staff of status changes to the power system stabilizer and automatic voltage regulator, ensuring continuous NERC compliance (Fig 10).

Hopewell Cogeneration Facility

After experiencing a significant increase in unit performance from CO_2 blasting the plant's HRSGs, personnel developed a formula to gauge the economic viability of tube cleaning based on several operating factors.

Environmental Stewardship

Athens Generating Plant

Installation of drip pans under each gearbox of the plant's air-cooled condenser effectively catches any leaking oil and facilitates visual inspection of the units, eliminating the possibility of negative environmental impact (Fig 11).

Batesville Generating Facility

Modifications to control logic for the plant's DCS to actively monitor ammonia tank level and flow rates, and resulting alarm procedures, significantly reduces the risk of an environmental release.

Klamath Cogeneration Plant

Plant personnel took their ongoing commitment to environmental stewardship to even greater heights by implementing procedures and programs to attain ISO 14001 certification, a comprehensive environmental management standard.

New Covert Generating Facility

Plant staff developed and implemented comprehensive procedures to effectively calibrate and manage gas cylinders for the site's continuous emissions monitoring systems (CEMs) in order to ensure environmental compliance (Fig 12).

Rokeby Generating Station

Modernization and upgrade of piping, forwarding skid components, and the containment structure for Unit 1's fuel

15. Dariusz Rekowski

16. Ron Gawer

17. Robert Kirby, William Vogel, Larry Hawk

18. Dave Cairns

19. Terry Toland, Steve Ellsworth, Chetan Chauhan

20. Ed Wong

oil system significantly reduce the risk of an oil release (Fig 13).

Safety Equipment & Systems

Central De Ciclo Combinado Saltillo

Inspired by the Japanese poka-yoke (fail-safing) method, plant personnel implemented a safety system for consistent color-coding of chemical containers, reservoirs, and storage areas to mitigate the risk of a chemical mix-up.

Dupont Sabine River Works Cogeneration Facility

Plant personnel increased safety and productivity by fabricating a removable roof to cover the turbine compartment during outages to protect both workers and equipment from weather-related complications (Fig 14).

Edward W Clark Generating Station

Installation of access doors and handrails on the turbine compartment roofs allow for safe, timely retrieval of personnel in an emergency (Fig 15).

Rokeby Generating Station

The plant mitigated operational safety issues and reduced outage duration for the combustor systems by installing access steps, a camera system for remote monitoring, and a movable maintenance platform.

Termoemcali

Plant personnel replaced wooden platforms with removable metal platforms on each side of the gas turbine to mitigate occupational hazards while performing maintenance.

Safety Procedures & Administration

Gateway Generating Station

To keep personnel safe from potential arc flash hazards during switchgear installation, the plant procured a remote-controlled, wireless racking device and developed safety procedures to mitigate risk (Fig 16).

Granite Ridge Energy

Installation of worksite safety permit stations for contractors and employees during routine maintenance and major outages enhances safety by raising awareness of potential hazards and increases efficiency of issuing and collecting permits (Fig 17).

Walter M Higgins Generating Station

Plant personnel used "lessons learned" to develop outage safety procedures to eliminate tripping hazards when entering and exiting the turbine enclosures during maintenance (Fig 18).

Klamath Cogeneration Plant

The dedication of plant personnel to develop and implement extensive occupational health and safety programs earned the facility OSHA VPP Star status.

River Road Generating Plant

O&M Plant personnel collaborated to implement area-specific safety risk assessments throughout the plant to enhance hazard awareness for both employees and contractors (Fig 19).

T H Wharton Power Plant

Developed and designed by plant personnel, Hogan's Alley is an obstacle course and competitive program that incorporates real-life scenarios to increase safety awareness through hazard recognition (Fig 20).

Design

Granite Ridge Energy

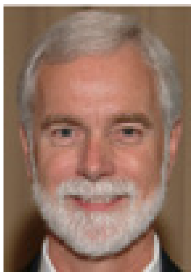
The plant installed baffles to adjust exhaust gas flow characteristics immediately upstream of the SCR which enabled an approximate 13% improvement in the ammonia/NO_x ratio and allows the facility to operate as intended with efficient control over its ammonia usage.

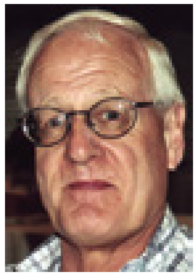
Continual vigilance required

With apologies to E F Hutton, when Bob Anderson talks about heat-recovery steam generators most everyone listens. Now in private practice (Competitive Power Resources Corp, Palmetto, Fla), Anderson learned much of what he knows about HRSGs first-hand as a combined-cycle plant manager for Progress Energy and later as the utility's resident expert/troubleshooter on heat-recovery boilers.

For the last several years, the consultant has spent a large portion of his professional time researching and solving problems associated with attemperators—a/k/a desuperheaters—in main- and reheat-steam systems. Improper design, operation, maintenance, and control logic for interstage attemperators, in particular, have been associated with a wide range of problems—the most serious being cracking of downstream piping. Because much of this piping is external to the boiler, a breach of the pressure boundary is a threat to personnel safety. Anderson pointed to attemperators as the leading cause of piping failures in combined-cycle plants.

Final-stage or terminal attemperators can be another component of concern. They sometimes are installed downstream of the superheater and/or reheater to maintain steam to the turbine at the optimal temperature during startup. If parts liberate from these components, and/or if spray water is not completely evaporated, the steam turbine can be damaged. Final desuperheaters are not intended for use after startup.


Anderson


Dooley

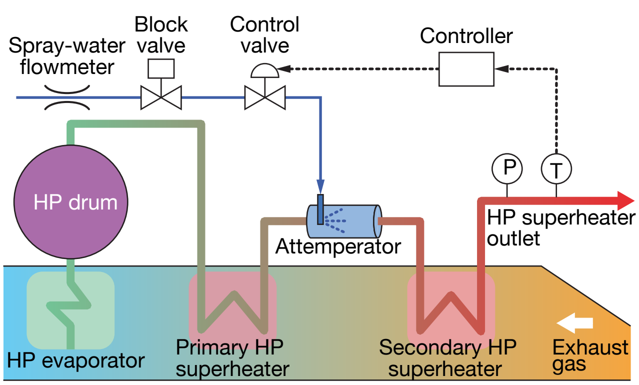
Anderson's presentation on attemperators at the 20th annual meeting of the HRSG User's Group, last February, in Houston, began with a diagram of a basic interstage attemperation system to get everyone in the room on the same page, so to speak (Fig 1).

The advantages of interstage attemperation, he said, tracing the flow of steam with a laser pointer, were reduced metal temperatures in the final superheater and reheater heat-transfer sections and prevention of carryover into the steam turbine. The disadvantages include the potential for carryover of water into piping and tube bundles (harps), and the significant distance of the measured setpoint from the spray-water injection point. The latter means it takes a relatively long time to respond to process upsets.

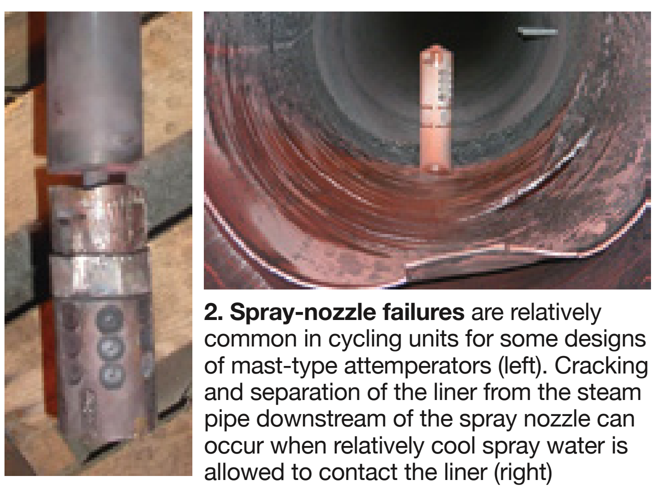
Anderson next explained how attemperation works and what can go wrong with any desuperheater system, including the following:

- Overshoot the desired outlet temperature.
- Overspray, or the introduction of unvaporized spray water into downstream harps, causing damaging thermal transients. Overspray is generally defined as an attemperator outlet steam temperature of less than 50 deg F above the prevailing saturation temperature.
- Defective spray pattern
- Equipment malfunction—such as leaking valve, clogged or worn spray nozzles, failed nozzle, failed thermal liner in downstream piping (Fig 2).
- Failure of downstream pressure part—such as pipe fittings, heat-transfer tubes, etc (Fig 3).

The insights Anderson offered on superheater and reheater designs that work and those that don't, and what to specify in terms of attemperator location and hardware features, were based in large part on findings from the nearly 50 HRSG assessments he and Barry Dooley of Structural Integrity Associates Inc have conducted over the last several years



1. Interstage attemperators are located between the primary and secondary superheaters and reheaters in heat-recovery steam generators



2. Spray-nozzle failures are relatively common in cycling units for some designs of mast-type attemperators (left). Cracking and separation of the liner from the steam pipe downstream of the spray nozzle can occur when relatively cool spray water is allowed to contact the liner (right) involving 13 HRSG suppliers, five gas-turbine OEMs (11 models of frame and aero engines), and eight steam-turbine manufacturers.

The plants were of many different types, including:

- 1 × 1 and 2 × 1 combined cycles, and cogen only, with operating hours ranging from 4000 to 130,000 hours and starts from 90 to 630.
- Single-, double-, and triple-pressure HRSGs, fired and unfired, reheat and non-reheat, horizontal and vertical gas paths.

The primary goal of the assessment effort, which is ongoing and global in scope, is to help operators become proactive in the identification of key drivers for cycle-chemistry- and thermal-transient-induced failures and damage mechanisms.

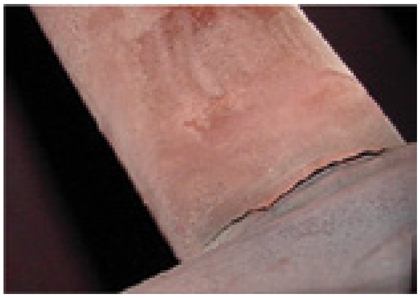
Anderson said that most attemperators have some kind of problem, which often is related to one or more of these variables:

- Distribution of heat-transfer surface area between the primary and secondary superheaters and reheaters.
- Type of gas turbine.
- Performance of the attemperator control system.
- Quality and type of attemperator hardware installed.
- Attemperator piping arrangement.

The many presentations and technical papers prepared by Anderson and Dooley based on their HRSG assessment program are having a positive impact. Consider the following survey results:

- Today 25% of the plants perform routine inspections or preventive maintenance on their attemperators, up from only 18% three years ago. At least annually, Anderson urged attendees, remove/inspect/repair the spray nozzle(s), control valve, and block valve, and do a borescope inspection of the thermal liner and its attachment points. Control valves in cycling service will leak eventually, he added.

3. Elbow cracked in cycling unit after repeated contact with spray water



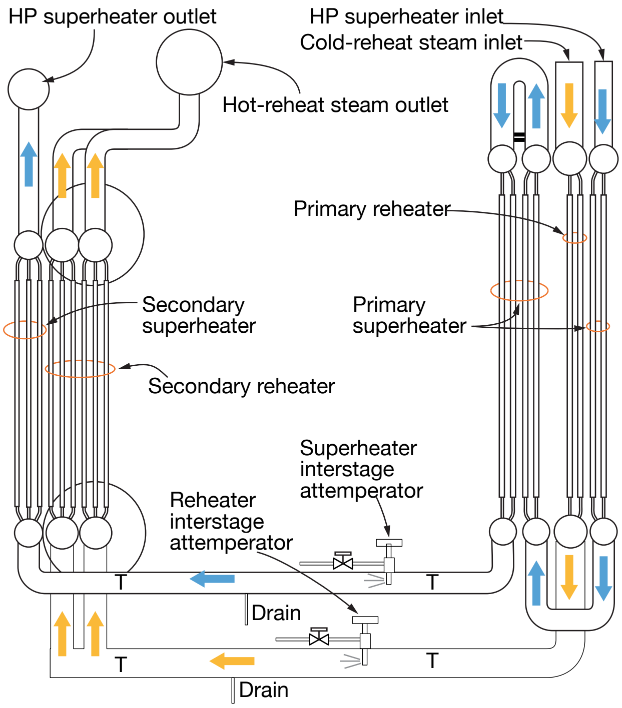
4. Repeated quench of hot tube caused by leaking attemperator control valve resulted in cracking from thermal-mechanical fatigue

- Today half of the plants have piping arrangements that allow unvaporized, or leaking, spray water to flow directly into harps during low (or zero) steam-flow conditions, down from 82% three years ago. If such leakage occurs while the harp is hot, severe thermal-mechanical fatigue damage, and sometimes immediate tube failure results (Fig 4). Anderson paused to mention that straight tubes are more tolerant to fatigue damage than bent tubes.

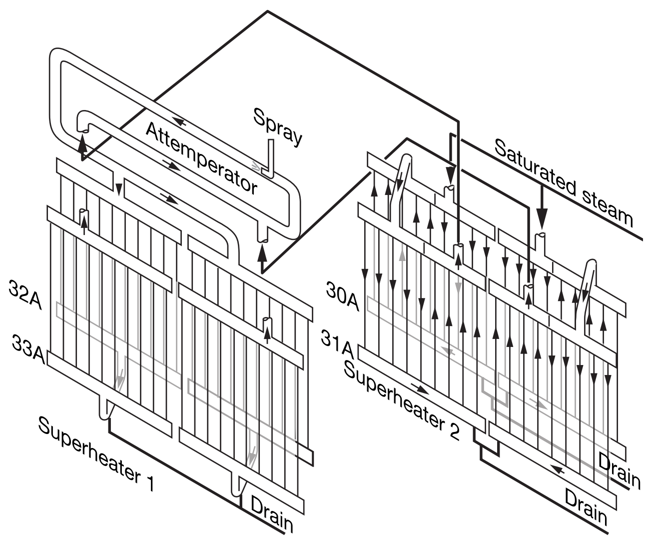
  Changes to the *ASME Boiler & Pressure Vessel Code* in 2007 no longer permit undrained attemperator pipe arrangements. Anderson showed attendees by way of one-line diagrams some desuperheater spray-water protection device arrangements suggested by Section I, Part PHRSG 2007. The consultant added, "Existing plants with undrainable pipe sections can benefit from the addition of a second, and 'bullet-proof' spray-water block valve and tell-tail drain to reduce the risk of undetected block-valve leakage."
- Today 28% have their spray control valve integral with the nozzle, down from 36% in 2009. This was good news, Anderson said, because this configuration has proven very unreliable in cycling service and no longer offered by most HRSG manufacturers.

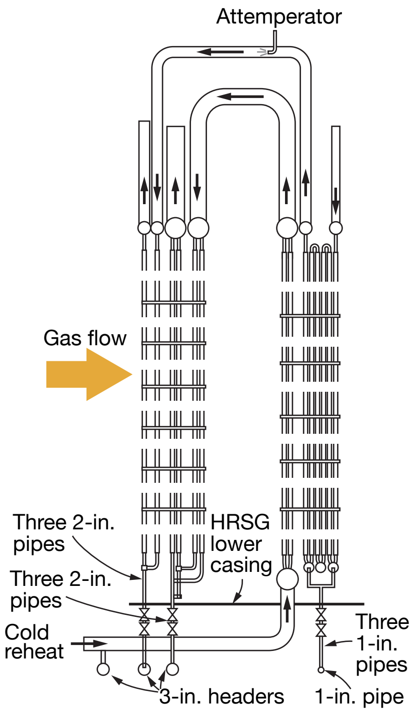
While the numbers are moving in

5. Long runs of piping connecting primary and secondary superheaters and reheaters have only one drain each. If these pipes suffer thermal humping, water will not drain. Instead, it will accumulate below the lower headers and possibly flow up into the harps—a condition conducive to extensive tube failures. Note: drawing is not to scale

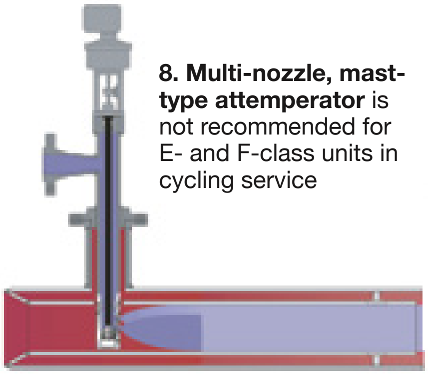


6. Problem waiting to happen. There is no drain between the attemperator and the superheater harps, so any leaking spray water (expected from valve wear and tear) must run into either the primary or secondary superheater, depending on which way the pipe slopes

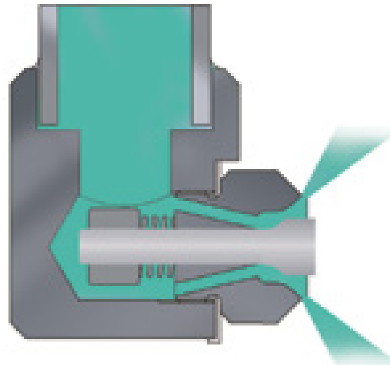




7. No drain between the attemperator and the superheater 2 harps as in Fig 6. However, here the pipe where the attemperator resides is too short to permit adequate residence time for evaporation at high spray flows

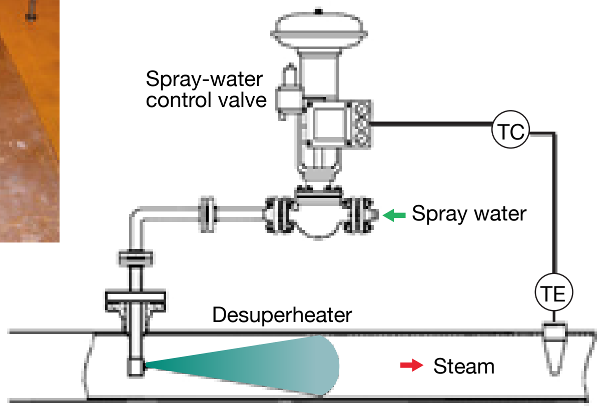


8. Multi-nozzle, mast-type attemperator is not recommended for E- and F-class units in cycling service



9. Variable-area nozzle provides efficient primary atomization regardless of steam flow

10. Fixed-orifice nozzles are not suitable for use in combined cycles in daily-start service



11. Mast-type attemperators having their control valves located outside the steam pipe generally work satisfactorily in combined-cycle plants

12. Ring-style attemperator improves atomization by injecting spray water perpendicular to steam flow

the right direction, there is still the opportunity for considerable improvement. Attemperator performance is an area that needs some attention. The latest numbers from Anderson and Dooley include the following: 29% of the plants surveyed indicate overspray, 29% experience startup steam-temperature excursions, and 47% experience attemperator control instability.

Hardware

There are scores of superheater and reheater surface arrangements, many unique. Anderson showed the group nearly a dozen, pointing out the pros and cons—mostly the latter (Figs 5-7). In Fig 5, the long runs of piping connecting primary and secondary superheaters and reheaters have only one drain each. If these pipes suffer thermal humping, water will not drain. Instead, it will accumulate below the lower headers and possibly flow up into the harps—a condition conducive to extensive tube failures.

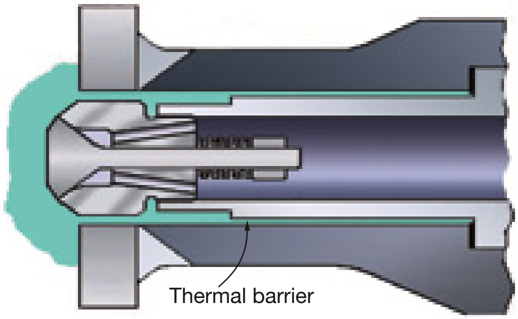
Fig 6 illustrates a problem waiting to happen. Note that there is no drain between the attemperator and the superheater harps, so any leaking spray water (expected from valve wear and tear) must run into either the primary (superheater 2) or secondary superheater, depending on which way the pipe slopes. As previously mentioned, the ASME Code now prohibits attemperator arrangements without automatic drain pots on the interconnecting piping.

In Fig 7, there is no drain between the attemperator and the superheater 2 harps as in Fig 6. However, here the pipe housing the attemperator is too short to permit adequate residence time for evaporation at high spray flows. A reheater attemperator is not shown, although one exists.

One of the reasons many superheaters and reheaters are not working as envisioned is because they were designed for operating criteria that never materialized. Recall that the vast majority combined cycles placed in service through the "bubble" years 2000-2004 were designed for base-load service. It's only recently that some of these units are running base-load; most had been cycling daily and/or required to operate at very low loads—another operating regime where attemperator performance shortfalls often surface.

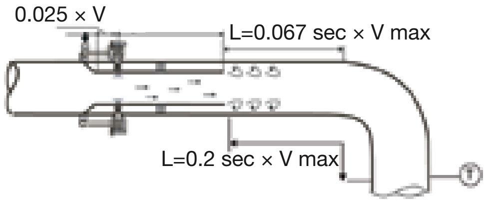
Variable-area probe-style attemperators were a popular choice for low- to medium-flow applications (and sometimes still are) when orders for plants powered by gas turbines surged in the late 1990s (Fig 8). On paper, these desuperheaters having spray-water control-valve trim in the steam flow stream, offered excellent turndown by virtue of their numerous spray nozzles, Anderson said. But cycling and the high steam temperatures associated with F-class engines, in particular, caused bending and cracking of the probes (a/k/a masts) in many units, rendering the desuperheaters useless.

Anderson showed cutaway drawings of a few other attemperators of the multi-port mast type, some designs quite involved, but all with serious limitations in cycling service. One supplier of reheater attemperators thought it could mitigate bending and cracking of long masts—generally attributed to bending moments created by the flow of steam and to flow-induced vibration—by shortening the masts to less than half the diameter of pipes they were installed in. The short-mast idea didn't work as planned: The spray pattern was ineffective.



13. Thermal barrier separates hot and cold working elements to mitigate the intensity of thermal cycles experienced by critical components (left)

14. Liner protects steam pipe from thermal sock, helps improve secondary atomization (below)



Anderson said that best attemperation results in E- and F-class combined cycles, based on his experience, are being achieved by variable-area spring-loaded spray nozzles (Fig 9). Fixed-orifice nozzles are not suitable for this service, in his opinion (Fig 10). The variable-area nozzles can be used in mast-type systems providing the moving parts of the control valve are located outside the pipe (Fig 11). Several attemperator manufacturers have adopted this concept with satisfactory results.

An alternative is the ring-style attemperator which admits spray water normal to the flow of steam (Fig 12), thereby offering better secondary atomization than the mast type, which sprays in the direction of steam flow. The ring design also ensures distribution of spray flow across the entire cross section of steam flow.

Atomization basics. Proper atomization and evaporation of the spray water supplied by an attemperation system is necessary both for good temperature control and to prevent water carryover. Complete assimilation of injected water into superheated steam involves three steps: primary and secondary atomization, and evaporation.

Primary atomization is the break-up of water into droplets by the attemperator's nozzles. Goal is to create as small a droplet as possible regardless of the water spray flow rate. Variable-area nozzles offer this capability, fixed-orifice nozzles do not. Secondary atomization refers to the break-up of large droplets by the dynamic force of the steam flow. But for secondary atomization to occur, the dynamic forces acting on a droplet must be greater than the viscous forces holding the droplet together and depends on the relative velocity between the steam and water droplet. This objective is maximized by the ring-type attemperator.

Finally, the small droplets produced by secondary atomization boil and evaporate. The time to achieve complete evaporation depends on the total surface area of the water injected and is proportional to the square of the droplet diameter. Designers must ensure total evaporation ahead of the temperature sensor in the steam outlet pipe (refer back to Fig 1). Wetting of the sensor would make it virtually impossible to control steam temperature as intended.

Attemperation system design. In addition to specifying that the spray-water flow-control element be located outside the hot steam environment, engineers at Control Components Inc, Rancho Santa Margarita, Calif, suggest adding a thermal barrier to separate the hot and cold working elements to mitigate the intensity of thermal cycles experienced by critical components (Fig 13).

A proper liner is an important element in every desuperheating station. In addition to protecting steam piping against thermal shock, it increases steam velocity to improve secondary atomization, creates vortices that improve atomization and enhance mixing, and assist with heat transfer and evaporation. CCI has done considerable research to ensure complete evaporation of spray water and predictable performance to avoid damage experienced by many owner/operators. Fig 14 presents the details.

Anderson offered a simpler approach: The "Rule of Five Up and Twenty Down"—that is, a straight run of pipe ahead of the spray nozzles equivalent to the total length of five pipe diameters and a straight run of pipe equivalent to 20 pipe diameters downstream. He said that use of a ring-style attemperator might reduce the downstream straight run by the equivalent of a few pipe diameters.

A follow-on article will help plant personnel troubleshoot attemperators using DCS data and to specify an effective controls arrangement to mitigate problems faced by many users. CCJ

Flow-accelerated Corrosion (FAC)

in Fossil and Combined Cycle/HRSG Plants 2013 International Conference

Call for Papers and Initial Information Tuesday, March 26, 2013 - Thursday, March 29, 2013

Associated Organizations

CEATI International/Centre for Energy Advancement through Technological Innovation
Combined Cycle Journal
Electric Power Research Institute (EPRI)
International Association for the Properties of Water and Steam (IAPWS)
PowerPlant Chemistry Journal
Structural Integrity Associates, Inc.

Westin Arlington Gateway

(1) 703-717-6200
801 North Glebe Road
Arlington, VA 22203
USA

The 2013 International Conference marks the second gathering of technical experts and end users to focus on all aspects of FAC in fossil and combined cycle systems. The inaugural conference held in 2010 was attended by 170 people from 21 countries and featured a technical program with 40 papers. The conference will be linked to the 2013 FAC Conference, May 21-24, 2013, organized by Électricité de France, which focuses on FAC in the nuclear power industry.

The 2013 International Conference on Flow-accelerated Corrosion (FAC) in Fossil and Combined Cycle/HRSG Plants will be held on March 26-28, 2013. Total attendance is targeted at 180 people. The conference will include an Exhibition Area and is seeking exhibitors and sponsors to support various conference activities. An Expert Panel and Roundtable Discussion is planned for the morning of March 29.

Who should attend the conference?

Anyone involved with FAC, including researchers, industry personnel (including engineers, chemists, operators and managers), and technical product and services organizations will benefit from attendance.

Summary Agenda

Day 1: Tuesday, March 26
07:00 Registration/Exhibition Open
08:00 to 17:00 Conference Sessions
17:30 to 19:30 Social and Networking Gathering

Day 2: Wednesday, March 27
08:00 to 17:00 Conference Sessions
17:30 to 20:00 Conference Reception and Buffet in Exhibition Area

Day 3: Thursday, March 28
08:00 to 17:00 Conference Sessions
17:00 Conference Adjourned / Exhibition Closed

Day 4: Friday, March 29
08:00 to 12:00 FAC Experts Panel and Roundtable Discussion

Call for Conference Papers

The conference will consist of both invited and contributed technical papers. Abstracts must be submitted by September 30, 2012, to guarantee consideration by the conference chairmen. Authors will be notified of acceptance by October 31, 2012. Authors of accepted papers should be prepared to submit the completed paper and/or presentation materials by February 15th, 2013.

Person to receive abstracts: Barry Dooley via bdooley@structint.com

Subjects to be covered during the conference include:

- FAC in Fossil Plants
- Conventional Fossil Power Plants
- Combined Cycle Plants with Heat Recovery Steam Generators
- FAC in Other Industries (Refineries, Pulp and Paper, Dairies and Food Supply Systems, Industrial Steam Plants, City Steam and Water Supply Systems, Geothermal, etc.)
- Cycle Chemistry Influences on FAC
- Materials Aspects of FAC
- FAC Research Activities
- FAC Damage Mechanisms
- FAC Modeling
- Programs for Management of FAC
- Predictive Methods
- Inspection and NDE Technologies
- Repair and Replacement
- Life Management
- End User Experiences

Conference International Advisory Group Members

- David Addison, Thermal Chemistry, New Zealand
- Bob Anderson, Competitive Power Resources, USA
- Dr. Geoff Bignold, GJB Consulting, UK
- Professor Albert Bursik, PowerPlant Chemistry, Germany
- Darryl Glanton, EPRI, USA
- Tom Gilchrist, Tri-State G&T, USA
- Andy Howell, Xcel Energy, USA
- Gary Joy, CS Energy, Australia
- Dr. Zhigang Li, TPRI, China
- Professor Derek Lister, University New Brunswick, Canada
- Des McInnes, Stanwell, Australia
- Keith Northcott, Eskom, South Africa
- Professor Tamara Petrova, Moscow Power Institute, Russia
- Michael Rziha, Siemens, Germany
- Professor Hiroshi Takaku, Shinshu University, Japan
- Stephane Trevin, Électricité de France (EDF), France
- Professor Shunshuke Uchida, JAERI, Japan
- Stan Walker, EPRI, USA
- Daniel Zinemanas, Israel Electric, Israel

For information as it becomes available, and to register, visit www.facfossilhrsgconference.com

HRSG issues similar worldwide

Don't delay. Make plans now to attend the fourth annual Australasian HRSG Users Group (AHUG) meeting, December 4 to 6, in Brisbane, Australia (sidebar). This conference and its associated workshops have grown dramatically in size and stature since the organization's launch in 2009. Prediction in 2010 was that were the 2009-2010 growth rate to continue, the 2011 meeting, held last December and profiled here, would have 80 attendees.

It did, about half also having attended in 2009 and/or 2010. O&M personnel representing utilities and independent generating companies, consultants, and equipment/services providers from six countries participated in the two-day 2012 conference; many stayed for the two half-day workshops on nondestructive examination techniques and attemperators the day after the general meeting concluded. Bullish members of the steering committee, chaired by Barry Dooley of Structural Integrity Associates Inc, think the upcoming conference could draw more than 100 participants.

A benefit of traveling West in December (summer in that part of the world) is to learn how your colleagues in Australia, New Zealand, and several Asian countries deal with many of the same problems you face. In some cases, their solutions are different; in others, they come up with the same answers, thereby reinforcing your decisions.

The information exchange at AHUG is vibrant, knowledge being transferred in one of these three ways during the general meeting to keep attendees engaged:

- Questions submitted by users prior to or during the meeting. In a few cases, the questions come from colleagues who can't attend the formal meeting and they receive their replies from a member of the steering committee after the event. AHUG is very proactive in the sharing of information among owner/operators of generating plants powered by gas turbines.
- Formal presentations by consultants, equipment/services providers, and users; six of these in 2011.

AHUG IV December 4 – 6, 2012

Brisbane Convention & Exhibition Centre

Register today: www.ahug.co.nz

The annual meeting of the Australasian HRSG Users Group (AHUG) provides a forum for sharing knowledge and experiences among owners, operators, manufacturers, service providers, consultants, and others with an interest in heat-recovery steam generators and associated plant processes and equipment.

The group's steering committee, chaired by Barry Dooley of Structural Integrity Associates Inc, has the following members:

John Blake, Stanwell Corp.
Mark Utley, Contact Energy.
Lester Stanley, HRST Inc.
David Addison, Thermal Chemistry Ltd.
Bob Anderson, Competitive Power Resources.
Des McInnes, Stanwell Corp.

Conference program

The 2012 meeting begins with two days of presentations and discussion on these subjects, among others:

- Heat-transfer components and pressure parts.
- Tube failure mechanisms, including FAC and thermal fatigue.
- Water treatment/cycle chemistry, including treatment options with internal deposits, chemical cleaning, and shutdown/layup/storage.
- Piping systems.
- Structures/ductwork, dampers, stacks.
- Valves.
- Supplemental firing.
- Controls.
- Environmental systems.
- Balance of plant.

The following are a few of the presentations on the upcoming Brisbane program, which may make this the top HRSG meeting ever in terms of content value:

- Creep-fatigue life assessment of a repaired main steam stop valve.
- Improving sampling techniques to optimize FAC management.
- Optimizing HRSG shutdown and startup.
- Establishing HRSG component lifetime and ramp rates.
- Hydrogen damage and FAC failures—a user case history.
- Superheater thermocouple installation and results—a user case history.
- Plant response to a major cooling-water ingress—a user case history.
- P91 main-steam elbow replacement—a user case history.
- Drum-level instrumentation and the latest ASME Code requirements.
- Advanced pipe/tube materials and the ASME Code.
- Optimal sampling and analysis methods for iron.
- Cost-effective HRSG performance assessment.

Two four-hour workshops are scheduled for the third day. "Next-generation HRSG design" will review the performance expected from the next generation of heat-recovery steam generators. One focus of the session will be features required to achieve faster startup, higher efficiency, and adequate component life while two-shifting. The content of the second workshop is a work in progress.

A small exhibition rounds out the program.

- Short case histories by owner/operators; eight of these in 2011.

A few exhibits were included at AHUG for the first time last December. The exhibitors were:

- Swan Analytical Instruments AG (Switzerland).
- OsmoFlo (Australia).
- Precision Iceblast Corp (USA).
- Duff and Macintosh Pty Ltd (Australia).
- Sentry Equipment Corp (USA).
- National Electric Coil (USA).

The following report on the 2011 meeting is based in large part on notes taken by David Addison, principal, Thermal Chemistry Ltd, Horsham Downs, Hamilton, NZ, for exclusive use by the **CCJ**. Addison is a member of the AHUG steering committee.

Pressure parts

A couple of questions got attendees involved and "warmed-up" in short order. The first came from a user having horizontal economizer tubes that he was having difficulty keeping clean and wanting to know if vacuuming up the debris was his only choice. Interestingly, this HRSG has vertically oriented tube bundles in the high-temperature section and horizontal tube bundles in the cooler regions of the unit.

A consultant suggested installing sootblowers and using as the cleaning medium HP superheated steam after pressure reduction to about 200 psig. Another consultant said his company had been successful by putting a tarp under the tube bundle to capture material and then blow downward with cleaning lances. A cleaning expert assured the questioner it was not a problem to spread the bundle and blow downward with high-pressure air to achieve the expected level of cleanliness—assuming the debris is primarily corrosion products.

Users with long-term experience may remember that the first pre-engineered combined cycles offered by GE Energy—called STAG units—incorporated HRSGs of its design and manufacture. These heat-recovery boilers had horizontal tube bundles and sootblowers (many of the early gas turbines were equipped for dual-fuel service or to burn oil only). Those still in use today typically are found in combined cycles powered by early Frame 7 engines.

Next came a general two-part question: Do attendees experience deposit formation on HRSG tubes and, if so, do they pose any operational or maintenance problems? What methods do users employ to remove the deposits, and at what frequency? First user to respond said his HRSGs are experiencing an increase in deposition and the deposits are high in sulfur. Plant personnel increased the temperature of water to the air preheater section from about 130F to 140F by use of a recirculation loop, but that hasn't had much positive impact. The questioner asked if it was best to look for other ways to minimize deposition or to just clean at some trigger point.

Another user said sulfur-rich deposits also were accumulating at the back end of his HRSG, increasing the pressure drop through the unit. That plant dry-ice blasts periodically to clean heat-transfer surfaces.

A respected consultant advised a performance-based solution. Increasing the feedwater temperature, he said, adversely impacts overall thermal efficiency. A rule of thumb is that you reduce output by 0.0184 MW/deg F rise in stack temperature. His recommendation: run to failure/clean rather than suffer the performance drop. Fouling is worst, he continued, with units having SCRs, particularly those overspraying ammonia. While that's true, it was a moot point for most in the room because HRSGs operating in Australia and New Zealand are not equipped with SCRs.

Another consultant suggested analysis of deposits by x-ray diffraction/x-ray fluorescence to accurately determine their composition and to track changes over time. He has identified deposits of ammonium sulfate and elemental sulfur around access doors where rain water/salt spray have leaked in; also has found ammonium sulfate on the last few rows of tubes and zinc sulfate deposits where zinc has come out of the casing paint/coatings. A user seconded this consultant's findings, having experienced the same at his plant.

A "mail-in" question from a UK user had to do with an odd header/tube arrangement on a double-wide HRSG with an alignment-plate configuration that didn't fulfill its intended function. Result: Wing tubes from the upper and lower headers flared out, leaving a gap at the bottom and top of the unit that allowed hot gas to bypass heat-transfer surfaces from the front to the rear of the boiler. The user said a series of short, flimsy gas baffles were really only a token gesture at filling these gaps, and that they were already starting to break up from high-cycle fatigue and relative header movement. This owner/operator's concern was the possibility of economizer steaming and increased possibility for flow-accelerated corrosion (FAC) in the evaporator because of a higher steam fraction in wing tubes.

A representative of the OEM in the room responded with a non-answer. A couple of consultants couldn't pass up the opportunity to talk, but they didn't say much of value either. Another user said he had a heat-recovery unit (not an HRSG) with a similar issue. In his case, during hot operation the tubes should have expanded to "fill in the gap" but didn't and some tubes suffered overheating creep failure.

Next, a heat-transfer expert said the "issue with gas bypass is major and can lead to major thermal transients. You have to be on top of this." One of the consultants who had responded earlier grabbed the handheld mic after thinking more on the subject and added, "These types of issues can be really bad for forced-circulation boilers, leading to dry out and dry-out related tube failures."

Chemistry questions

One user, in particular, had several questions related to cycle chemistry. The first had to do with the capabilities of commercial laboratories in Australia and New Zealand to analyze anions and cations down to single-digit parts-per-billion levels. He got a good news/bad news answer from his colleagues: No labs could at present, but hopefully one or more will be able to do so soon. A chemist added that bench top UV-Vis spectrophotometer methods are no good for iron; you must use methods based on atomic absorption flame spectrometer or inductively coupled plasma to actually measure total iron.

Second question: "We found FAC in our LP system, particularly in the LP drum risers. Before the outage we had carryover issues from our LP drum, so only ammonia was being dosed. The carryover problem has been rectified and tri-sodium phosphate (TSP) is being dosed. The inspector suggested the FAC was caused by steam velocities, whereas I suspect it was caused by the ammonia residing in the steam rather than in the liquid phase. What do you think?"

David Addison, Thermal Chemistry Ltd's chief chemist, shows his determination to get a front-row seat at AHUG's fourth annual meeting, December 4 – 6 at the Brisbane Convention & Exhibition Centre. Addison (#200), a member of the AHUG steering committee, will be covering the upcoming conference for **CCJ**.

One of the world's leading water chemists replied this way: "IP and LP risers are the No. 1 locations for FAC in HRSGs—all two-phase—and oxidizing chemistry is not able to deal with it. Raise water-phase pH using solid alkali; then change the risers to P11." In two-phase locations, he continued, magnetite solubility peaks at about 350F, so knowing the temperature of the fluid in the risers is critical. A pH of at least 9.6 is necessary; carryover must be prevented to avoid steam contamination.

The chemist stressed drum performance as critical. A common mistake in FAC management, he added, is to try to fix single- and two-phase FAC issues at the same time. Deal with each form of FAC separately. The questioner replied that his plant just changed out drum internals with carryover being reduced from 5% to 0.02% and had implemented TSP treatment, so significant improvement in the FAC issue was expected.

The water chemist jumped back into the dialog, suggesting that the user be careful of links to velocity. FAC is driven by turbulence, he said, which in this case is created by a torturous path. He also recommended that the user try sodium hydroxide in place of TSP, saying it was more commonly used now.

Third question by the same user: "Our unit ramps up and down daily and we have trouble meeting steam conditions as a result. Is there any way to reduce the spikes in cation conductivity (sometimes as much as 0.6 microSiemens/cm experienced when units are changing load regularly)?

Another user offered that his plant also has issues with steam quality being a cogen facility. Solution was to improve the HRSG chemistry to help lower carryover rates; the very high TDS levels that had been experienced were reduced. He suggested that the questioner regard short spikes as cumulative damage. The questioner remarked that his steam turbine was sandblasted following a major salt-ingress occurrence and the boiler was chemically cleaned at the same time.

An experienced chemist took the mic. I get asked about "damage" all the time. Before answering, he said, I want to know the conductivity after cation exchange (CACE) by way of ion chromatography (IC). If chloride and sulfate are found, you should be concerned at the HP evaporator and the phase transition zone in the steam turbine.

Sample an HP evaporator tube to determine its condition, he suggested. If you find significant deposits then the chloride and sulfate levels are a major concern because they can concentrate up and cause under-deposit corrosion issues. In the steam turbine, crystalline deposition is a major concern because of its impact on blades. When the unit is shut down, the deposits absorb moisture and cause pitting, which, in turn, leads to stress corrosion cracking (SCC). Offline turbine protection should be implemented.

Holding onto the mic with a vise-like grip, the same user asked a fourth question: "When you return to service after a long outage during which the Rankine cycle was drained, and where work required the boiler to be open to atmosphere for a significant period, what's the best way to clean the system to ensure steam-quality specifications are achieved as soon as possible during run-up?"

About a dozen attendees responded to this question. Most replies were short—for example, good procedures and planning are vital to success, get a suitable sample early in the startup, have a chemist in attendance to support the operations team (not suggested by a chemist, but fully supported by all the attending chemist consultants), etc. A chemist polled the group, "How many plants represented have chemists?" By show of hands, four times as many plants with chemists than without. That's in sharp contrast to US experience, where many generating companies have one or two chemists to service an entire fleet.

A user said a general procedure that worked well at his plant was to complete all work and put the plant in a dry shutdown condition with desiccant, dry air, etc. Then fill the boiler with high-quality water and arrange for extra demin to allow heavy blowdown during the ensuing start. Result: Perfect steam quality in less than 24 hours.

The question was answered best, perhaps, by a chemist in the room who offered the following procedure right off the top of his head:

1. Make sure chemical dosing system is properly lined up, tested, and ready to operate; verify that chemicals are fresh.
2. Fill the condensate system and circulate with chemical dosing on for about an hour. Then dump the hotwell and fill/dose/circulate again to purge outage debris. Repeat until the system is clean visually, and chemically via lab testing.
3. Fill HRSG and dump; flush with ammoniated water if plant configuration allows this.
4. Refill the HRSG to startup condition with elevated ammonia concentration and standard phosphate/caustic dosing levels. Have ammonia about 10% to 15% higher than normal for a cold start because you'll lose ammonia via the steam vents faster than you normally would.
5. Get all chemical analyzers running on demin water and have spare sets of sample-line filters easily accessible. The filters installed will block as you bring the plant into service and you'll want to change them out quickly.
6. Upon firing the gas turbines, go to "full-open" on continuous blowdown.
7. Blow down sample lines hard as soon as there is sufficient pressure to clear the lines. Rack filters likely will block up; be ready to change them a couple of times.
8. Bypass steam to the condenser until steam purity targets for the turbine are achieved. You never really know how long this will take. Don't rush the process and approve the turbine start before acceptable steam purity is achieved. Steamers may look indestructible, but they're very sensitive to what they ingest.
9. Watch the evaporators for drops in pH. Be prepared to manually dose with phosphate/caustic to keep pH where required.
10. Maintain high blowdown until the system settles down and purrs. This may take a few days.

Notebook filled, the user with the four meaningful questions above yielded the mic to the representative from a cogen plant serving the dairy industry. He had a very practical question: Are there any other owner/operators of cogen plants serving the dairy industry present and, if so, do you have the potential for organic contamination of condensate returns by milk products? A few hands shot up. Have you had any success in detecting condensate contamination online—such as by using TOC (total organic carbon) analyzers?

One person in the room acknowledged milk ingress into the HRSG, which left a white deposit on internal surfaces of the water/steam circuit. Another said his plant had issues with contaminated caustics (organics suspected) and tested for TOC. Two other users mentioned investigating instrumentation to monitor condensate returns. Both had TOC on their lists; one also was considering monitoring turbidity, sodium, and conductivity. Not much there to help the questioner except some sympathy.

A representative of a water-treatment services provider said his company had experience in this area and noted that virtually all cogen plants serving dairies were susceptible to condensate-return contamination by milk products. To minimize the impact of contamination, his company has an indirect TOC project underway that promises a very fast response time via an optical-based process. Commercial release is planned by summer's end. You'll undoubtedly hear more about the early operating results of this instrument if you attend the upcoming meeting in Brisbane.

Case histories

Morning tea over, the group was treated to short case histories/experiences by several participants which generated considerable follow-on discussion. Regarding "tea," Chairman Dooley promises top-quality coffee will be available to all Americans (and others) who cannot adapt to local customs before the 2012 meeting begins.

Thermal fatigue of reheater tubes. The facts: A reheater tube in a 12-yr-old HRSG failed during shutdown; steam poured out the stack a few hours after the gas turbine was removed from service. Inspection revealed weld cracking at upper tube-to-header joints in Reheater 1 and nowhere else. Lab work fingered thermal fatigue as the failure mechanism. Lab also found defects/stress-relief cracking in tubes from the time of manufacture.

Root cause analysis (RCA) considered the following:

- Thermal load.
- Possibility of condensate moving through the system at startup and shutdown, thereby creating a severe thermal transient.
- Malfunction of the bypass control valve—sticking, for example. Reheater 2 was equipped with thermocouples that indicated large thermal fluctuations in those bundles. Although there were no t/cs in Reheater 1, thermal fluctuations were assumed given the Reheater 2 data.

Conclusion drawn was that thermal fluctuations combined with pre-existing cracks led to fatigue. The presenter's question to the group: Why only failures at tube connections to the top header? No cracks were found at the tube/lower header joint about 30 ft below.

An attendee noted from the slides shown that failures occurred in the middle of the header rather than at the ends. Why? The speaker guessed that the bottom header drain location might have influenced which tubes were affected and the thermal loads on individual tubes.

"I often see signs of condensate entering the bottom reheater header," an experienced consultant offered. Sometimes the problem can be traced to the bypass, sometimes it's poor drainage. Another possibility is rotation of the top header, which can generate the stresses that lead to failure. I see from the slides," the consultant continued, "that this is an upflow design; therefore, the drains were much more likely to be a major contributing factor."

The representative from a HRSG supplier said his company was seeing much interest lately by customers in ordering harps with t/cs installed for monitoring purposes. He added that as many as one-fifth of the new units would be so equipped. "An interesting change in the market," he concluded.

Spikes in conductivity after cation exchange. LP steam CACE spiked with 50-MW load changes during commissioning. Sodium went from 0.5 ppb during normal operation to as high as 50-100 ppb during spikes. CACE and sodium also spiked in condensate. LP drum had four "T" risers into the drum. Carryover testing according to procedures developed by the International Association for the Properties of Water and Steam (IAPWS) revealed these results: HP drum, 0.09%, IP drum, 0.02%, LP drum, 1.76%.

Physical inspections confirmed carryover from the LP drum, with phosphate deposition. A warranty claim was submitted and accepted; "T" risers were modified and carryover dropped to 0.01%. Conclusion: Purely mechanical carryover; no contribution from cycle chemistry or drum level. Comments/observations from participants included the following:

- Chemist. Carryover tests are very important. Testing program should include a run with a raised drum level as well. This is particularly important for the IP drum based on worldwide experience.
- User. Did you consider carryover damage to the LP turbine? Presenter said it was considered and a proper inspection would be conducted during the next outage.
- Boiler consultant. Also need to inspect the superheater; don't just stop at the turbine. This comment was countered by a chemist who suggested looking at the reheater, not the superheater because of solubility impact.
- User. How many others have had this experience? Is it common for the OEM of record? A chemist said carryover was not specific to the OEM; the speaker reminded that carryover in this case only was a problem during significant changes in load. An attendee representing the OEM said not everyone was systematically measuring carryover.

Transition-duct redesign. Nominal ½-in. liner with studs applied using a stud gun. Damage noted in March 2000: Sections of liner plate had peeled away; backing angle and stud failure relatively common. Significant insulation loss caused overheating of the casing. Had to shut down twice annually for three days each time to make repairs.

First major repair, in 2001 was to rebuild the eastern wall of the duct in-kind. Over the next several years the original western wall failed in sections and partial rebuilds were done as necessary. Liner failures continued on the eastern wall in areas of greatest turbulence. In 2009 the decision was made to redesign and rebuild the eastern and western duct walls during the 2010 major outage.

The new design featured smaller sheet sizes, use of four nominal ⅛-in. overlapping sheets instead of one nominal ½-in. sheet, sheets fixed at one point only, more studs per unit of area. The old liner system was removed. Inspection a year later revealed no issues; plan is to inspect every six months during regular maintenance outages. Next up is a floor replacement, likely in fall 2013 during a hot-gas-path inspection. Roof replacement is planned for 2016.

A user wanted to know if anyone else had similar issues with Type-409 stainless steel. The designer of the new liner system said performance of Types 309 and 409 normally is acceptable. However, he added, pin/stud location is critical to prevent hang-ups and ripping caused by restricted expansion. Other problems include vibration and associated fatigue. Corners can be an issue as well; must get them correct.

HRSG cleaning. High backpressure was in evidence right after a three-month major outage in 2010, a user told the group. Output was restricted to 350 MW, a drop of nearly 50 MW compared to the plant's capability before the outage. Important to note that during the outage, no steps were taken to protect the HRSG against material wastage even in an area characterized by high humidity.

Visual inspection revealed tube panels fouled with acid and ammonium salts that had accumulated during operation, plus corrosion products caused by poor offline storage conditions. The stack damper also was found out of alignment. It was repaired and produced an immediate improvement in backpressure. Baffles also were removed from module 5, reducing the delta P a bit more.

CO_2 cleaning was pursued using the latest techniques to assure maximum effectiveness—such as the use of tube spreaders for "deep" cleaning. Only about two-thirds of the tubes could be reached. The owner was concerned about CO_2 in a confined space and provided extra ventilation air by way of air compressors. There were no issues.

Outage took 12 days and photo records were compiled for all modules cleaned. Pre- and post-cleaning photos show good improvements and some minor fin loss. About 7 tons of material was removed and the unit is now capable of achieving 380 MW. Lessons learned included (1) access is very important (an extra access door was installed in the SCR ductwork) and (2) take precautions during HRSG layup to prevent metal wastage. Regarding the latter, when the HRSG is placed in "storage" today, steam sparging is used to raise metal temperatures and prevent moisture formation.

A question was asked on how steam sparging is done at this plant. The owner said steam connections are already there. They are coupled to the auxiliary boiler and steam is injected into the downcomers with a nitrogen over-blanket.

Cycle chemistry trifecta. Optimum cycle chemistry to deal with FAC and under-deposit corrosion, plus phase-transition-zone failures in steam turbines, was a practical presentation by a noted chemist of value to every owner/operator in attendance. He said system chemistry must be designed to (1) address all possible HRSG tube damage/failure mechanisms, (2) minimize corrosion-product transport, and (3) protect the steam turbine against sulfate and chloride deposits in the LP section and sodium hydroxide deposition on IP turbine blades. The presentation also addressed the fundamental level of instrumentation required to achieve these goals and the key elements of a management program to prevent bad cycle-chemistry situations.

A three-pronged approach is needed to mitigate FAC, the speaker said:

- All-volatile (AVT(O)) or oxygenated (OT) treatment to control single-phase FAC.
- Elevated pH (9.8 recommended) to control two-phase FAC.
- Monitoring of total iron to ensure the "Rule of 2 and 5"—less than 2 ppb total iron in condensate/feedwater and less than 5 ppb in each steam drum.

Single-phase FAC is "switched off" by the oxidizing environment, but you must assure sufficient "oxidizing power" attendees were told. Best way to determine oxidizing power is to monitor (1) the level of oxygen at the condensate-pump discharge and boiler-feed pump, (2) the color of LP and IP drums for the "ruggedness of their redness (R of R)," and (3) low levels of iron transport.

Two-phase FAC is controlled by the pH of the water phase. Once single-phase FAC is under control, review iron levels. If elevated, then check wall thicknesses, increase pH with ammonia towards 9.8, and add sodium hydroxide or tri-sodium phosphate in accordance with IAWPS guidelines to ensure the pH of the water phase is correct.

Under-deposit corrosion (UDC) presents the greatest risk to HP evaporators because they have the highest heat fluxes. UDC and FAC are linked: FAC corrosion products increase the risk of UDC in the higher pressure parts of the cycle. To control UDC, you need low levels of iron and low levels of deposition in the HP evaporator. Plus, you must sample tubes from the HP evaporator (chemically clean as required) and install the proper instrumentation to control the entry of contaminants into the condensate/feedwater system.

The speaker said that based on his experience, most plants are under instrumented and not taking HP-tube samples, so they're not controlling UDC risk very well. He added that poor chemistry selection contributes to heavy tube deposits in the HRSG and increases the risk of UDC failures.

A user wanted to know how much dissolved oxygen is needed to achieve "optimal chemistry." The speaker said there was no one-size-fits-all number. It needs to be capable of holding feedwater iron at a low level while producing the R of R in the drums. If you are below 10 ppb in a combined-cycle plant, he added, then you're unlikely to have the oxidizing power to provide the level of protection needed.

Is there an indication that you've gone too far, another user asked. The chemist said you really can't have too much oxygen for the LP portion of the cycle, but you don't want more than 10 ppb of dissolved oxygen in the HP evaporator tube bundles—so this is what has to be controlled. Next question: What's the best location for HP evaporator tube sampling? Answer: In a horizontal HRSG, extract the sample from as high up the lead HP evaporator tube as possible. This is where you'll find the worst deposition. If you can't gain access to the worst tube, then better to have the next tube rather than no tube at all.

High-energy piping, P91 in particular, was the source of much discussion at the meeting with several users reporting such issues as incorrect filler material, welds with defects, difficulties in welding T91 to P22, hardness too high, hardness to soft, replacement of off-spec fittings and pipe sections, construction records not matching what's installed, incorrect drawings, etc.

Order was brought to the subject of P91 by one of the world's top consultants on advanced materials for powerplant applications who offered his thoughts on how owner/operators might organize and manage a high-energy piping (HEP) program for their plants. He began with goals. A HEP management program, he said, should have two major goals: personnel safety and high unit reliability. Despite such high-profile goals, it's disconcerting, the expert continued, that HEP issues are on the increase because of limited maintenance budgets and the loss of technical expertise from the industry.

To reverse the trend, users need to know where to look for problems in HEP and headers; a random approach is not productive. An organized approach to ranking the probability of which HEP components will fail is needed. The ranking should be based upon each component's potential for damage and incorporate results from inspections and stress analyses.

Once components are ranked in order of risk, inspections can begin. Goals for your inspection program include the following;

- Ability to detect the type of damage most likely to occur as early as possible.
- Provide rapid and repeatable results at the lowest possible cost.

The inspection process becomes substantially more complex, the speaker continued, when the material of construction is Grade 91 or one of the other creep-strength-enhanced ferritic (CSEF) steels. Controlling the microstructure of these unique steels dramatically increased the levels of technical and process control required during steel production and through all phases of implementation.

As the earlier discussion indicated, damage to piping system and other components made from these steels is widespread. Further, the location of damaged material is unpredictable, reflecting poor control of processing steps and poor record-keeping. With such poor quality control, the materials expert said, you cannot from a cost standpoint certify with complete confidence the condition of any component/system after installation. At this time, he continued, there exists no nondestructive inspection tool that can conclusively identify deficient CSEF material cost-effectively. CCJ

‘Please bookmark our new web location at www.7Fusers.org,’

Reminded Outgoing Chairman Ben Meissner of Progress Energy Inc and Incoming Chairman Sam Graham of Tenaska Inc as the 2012 meeting of the 7F Users Group drew to a close in San Antonio, May 18. Earlier in the week, Meissner had walked attendees through the website, telling the assembly that the new online home for the organization is operated by the user group for its owner/operator members. Further, that the previous website, hosted by a third party, would likely remain active but would no longer be supported by the steering committee.

Meissner demonstrated, using a series of slides, how the new website offers better archival search capability, easier access, and improved functionally compared to the previous portal. The group’s forum and presentation archives are available to user members on the new site.

All future conference announcements, registrations, etc, will be conducted via 7Fusers.org. Certain information from the OEM will be there as well, along with the forums of great value to users (discussion, emergency, spare parts, etc). An email interface is included as part of the new forum setup; alternatively, users can go directly to the forum to create or respond to posts.

7F USERS GROUP

Save the date: 2013 meeting, May 20-24

Hyatt Regency Greenville
220 North Main St
Greenville, SC 29601

Existing user profiles have been uploaded to the new website, but you have to log onto the new site to register your password. If you’re a 7F user and never registered on the old site, go to www.7Fusers.org, click “Apply” on the horizontal toolbar at the top of the page, and sign up today. No charge. If you encounter any problems, contact sheila.vashi@7Fusers.org.

Immediately following the announcement of the new website, Meissner polled attendees to learn more about them. About half of the audience, by show of hands, said this was their first 7F meeting. Well over half the group had at least two years of experience operating and maintaining the GE engine, with about 40% saying they had participated in at least one major inspection. Units in peaking, cycling, and base-load service were represented about equally.

The starts leader in the room was over the 3000 mark; six engines were said to have recorded more than 100,000 operating hours. More than half the group had GE long-term or parts services agreements; about 30% self-performed maintenance.

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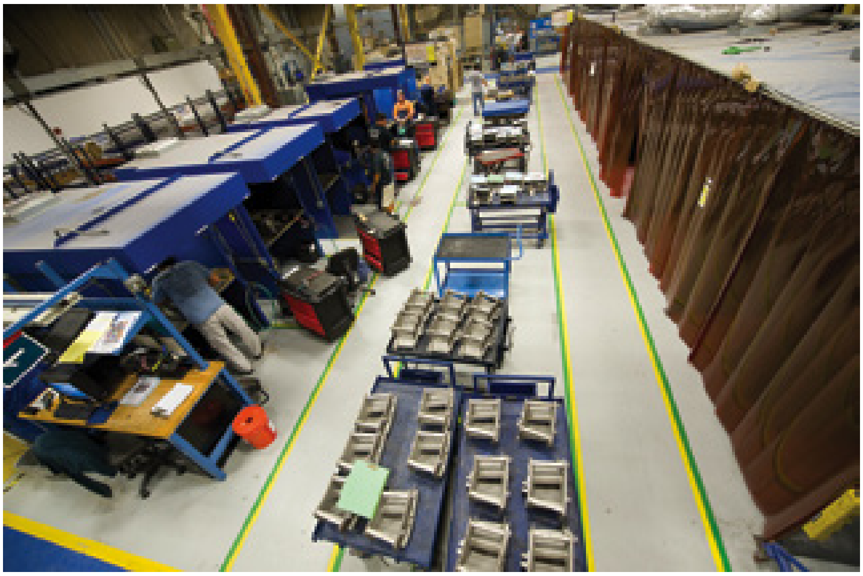
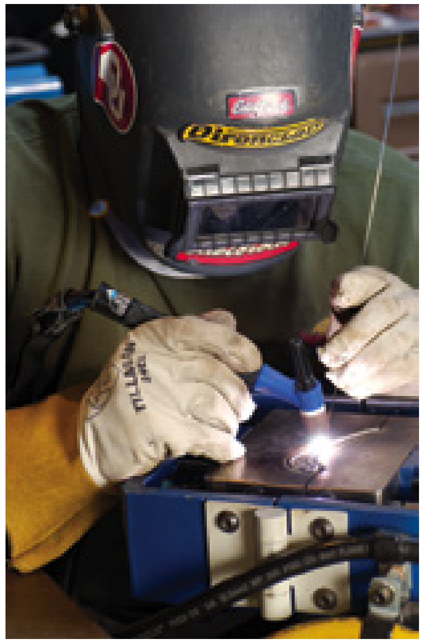
‘7F Week’ highlights

By the time Meissner opened the forum portion of the 21st annual conference on Tuesday morning at the Westin La Cantera, many of the

Steering committee, 2012-2013

Back row (l to r): Eugene Szpynda, NYPA; Jim Sellers, Entegra Power Group; Richard Clark, Southern California Edison; Ed Fuselier (Vice Chairman), Direct Energy; Jeff Gillis, ExxonMobil Chemical; Ken Gross, Con Edison. *Front row:* David Such, Xcel Energy; Dan Giel, Progress Energy; Sam Graham (Chairman), Tenaska; Ben Meissner, Progress Energy; Bob Holm, OxyChem; Paul White, Dominion Resources; Peter So (Treasurer), Calpine. *Camera shy*: Tom Berry, Tampa Electric; Art Hamilton, Calpine





1. Vane repair line (above) extends from one side of the shop to the other
2. New tip is welded on a 7FA+e first-stage bucket (right)

more than 250 owner/operators in attendance, a record, had already participated in a day of special events. Monday, May 14, featured an eclectic program that included a tour of Pratt & Whitney Power Systems' San Antonio shop, a workshop on heat-recovery steam generators conducted by engineers from HRST Inc, a golf tournament, and a special session on 7F rotor dynamics, vibration analysis, and troubleshooting developed by GE Energy. A reception and dinner completed the day.

The golf tournament, which began at 8 am on one of the host hotel's two onsite courses, was dominated by players from the 108 participating equipment and services providers. The morning-long HRSG Spotlight Session focused on fatigue cracking and was attended by about three dozen users (p 119). Amy Sieben, PE, and Scott Wambeke, PE, divided up the subject matter, with Sieben covering fatigue and other failure mechanisms in superheaters/reheaters and panelized economizers and Wambeke handling return-bend economizers and steam-drum nozzle cracks.

The approximately 100 users who visited the PWPS shop found a bright, modern repair facility with the latest inspection and repair tools and efficient production lines (Figs 1, 2). The facility is a one-stop shop—strip to ship—for inspection, refurbishment, and repair of F-class parts.

General Manager Gerald D Hill and his team of knowledgeable tour guides told the gas-turbine owners and operators that, in addition to restoration repairs, PWPS pursues design improvements with the goal of providing refurbished parts that are "better than the original" where possible. The collaborative process of component improvement involves (1) identification of issues based on field experience, (2) re-engineering and modeling of improved parts, (3) laboratory validation, and finally, (4) field validation.

The users-only sessions on Tuesday covered the 7F compressor, safety practices and lessons learned, controls, and auxiliaries. Vendor presenters included PSM, ExxonMobil Lubricants, National Electric Coil, and Advanced Turbine Support LLC. Wednesday's user-only lineup featured a combustion and turbine session, generator session, and open discussion before presentations by Environment One Corp, Praxair Surface Technologies Inc, PWPS, and Turbine Technology Services Corp, among others. Vendor fairs, including dinner, completed the Tuesday and Wednesday programs.

Thursday was GE Day. Presentations and discussion covered the entire engine from the air inlet house through the generator, capped off with a reception and OEM product fair. Friday's program, which ended at noon, featured parallel sessions on D-11 and A-10 steam turbine maintenance and GE controls and diagnostics.

User presentations, discussion

The closed sessions at most user-group meetings serving owner/operators of frame-specific gas-turbine assets were structured similarly until recently. The standard formula was to start at the inlet air house and work back through the engine covering, in turn, the compressor, combustion section, turbine, generator, and control system. Session moderators would stimulate discussion using key words, recent experiences announced on bulletin boards, etc.

Example: "Who's not getting expected life from their air filters and what are you doing about it?" Air filters typically were good for 30 minutes of discussion. It seemed that everyone had an opinion or experience to share on this subject. Meeting after meeting many of the same experiences were shared—certainly fine for first-timers, but not many ideas for the veterans to take away. Interspersed between discussion sessions would be one or more relevant vendor presentations. With this format, the questions raised and the ensuing discussion often were predictable.

The 7F, 501F, and 501G user groups have broken the mold, contributing to a higher level of energy at conference

Mission statement

7F Users Group Inc is organized to provide an open forum through conferences and technological aids to the owner/operators of 7F combustion turbine/generator systems for effective communication, discussion, and information dissemination regarding the operation, maintenance, inspection, troubleshooting, and repair of such systems to maximize equipment performance and reliability. These purposes will be achieved through providing an opportunity at meetings, conferences, company email, and website for the open exchange of ideas among owner/operators and owner/operators with vendors.

activities. All participants benefit from the new format, which has the following key elements:

- Steering committees deep in numbers and knowledge.
- Active participation by all steering committee members, both in making or sponsoring presentations by owner/operators and by contributing to and facilitating discussion forums.
- Eliminating vendor presentations from the user-only sessions and encouraging greater participation by equipment and services suppliers in forums held just prior to the vendor fair. At the 7F meeting, which had exhibitions on two evenings (different vendors each evening), there were six 45-min presentations by suppliers each day, conducted in two time slots following the afternoon break (three companies presenting in parallel in each session).

The 7F steering committee, 15 members strong, has a good blend of experienced "youth," hard-nosed O&M managers, and engine experts with more than 25 years of industry service. One of the meeting's non-technical highlights was the recognition by the current steering committee of two of the user group's founding members in attendance, Pierre Boehler of GenOn Energy Inc and Bill Wimperis of Constellation Energy.

Wimperis, who chaired the first several 7F conferences, represented Baltimore Gas & Electric Co at the first meeting 21 years ago; Boehler was working for Potomac Electric Power Co at that time. Both engineers continue to serve the industry as members of the 501G and CTOTF steering committees, respectively. An interesting contrast: The first 7F meeting was attended by 14 managers and O&M personnel from four electric utilities, this year's conference hosted more than 250 user attendees from perhaps a hundred generating companies—both regulated and unregulated.

In round numbers, there were a dozen user presentations at the San Antonio conference and they stimulated hours of open discussion so compelling no audible buzz from sidebar conversations was in evidence—unusual for a large audience in a cavernous ballroom. Critical to discussion management is having a team of experts on the floor to clarify questions where necessary and to answer them when others present cannot. The 7F steering committee does this to perfection.

Compressor section

The first user to present said he was concerned by the migration of compressor rotor-blade spacers discovered on two 7241s during their second HGPs. The units had about 1800 starts each but were transitioning from a starts-based regimen to base-load service. The units' first majors probably are two years off. This owner/operator was not sure what should be done to address the migration issue, if anything, and asked colleagues in the audience to share relevant experience.

His investigation revealed no vibration problems resulting from spacer migration. In fact, calls to several users before making the trip to San Antonio did not uncover any vibration issues in the fleet that could be linked to spacer migration. The OEM's response, he said, was "don't worry." However, GE expressed some concern that if the migration had occurred in rows 7 and 8, where the spacers align, a combined migration of the two rows could happen in the future.

Four attendees said spacer migration had occurred on their machines but there had been no negative effects. One of these users said he used to work for the OEM and had seen many instances of migration but no problems resulting from that movement. Yet another owner/operator had experienced migration on Frame 5s and 7EAs and thought it might be the result of poor craftsmanship—specifically, poor staking.

Someone else said that if just one or

two spacers migrate it's one thing, but if several in a small section of the rotor move, then you could throw the unit out of balance. He reported seeing this on peaking machines and attributed the migration to "thermal ratcheting." A few others confirmed this based on their experiences with 7B-EAs. The OEM reportedly did field restaking for one user to correct for movement of one spacer.

Is your S17 solution the right one? A user reported that the back ends of some of his company's 7EAs and 7FAs have had issues. The OEM recommended a shrouded S17 to strengthen the back end of one FA, but material distress was identified when the unit was opened up a year later. Some attendees seemed surprised to learn there are several S17 designs. The latest has staked bolts, older version welded bolts. Washers can be used, or not. In some instances where they have been used, washer rotation has caused rapid wear. Another variable: Some bolts have two tack welds, some one.

Discussion included mention of fretting on the ID shroud face near where adjacent vane segments butt against each other, as well as heavy wear in the V-seal slot. The amount of clearance between the shroud and S17 airfoil tip was brought to the floor. A couple of users measured gaps of up to about 30 mils; group consensus was that one-third that would be better and probably would mitigate the wobbling of parts experienced in some instances.

It appeared there were more questions than answers regarding S17 issues and that the discussion was likely to continue next year in Greenville (May 20-24, 2013 at the Hyatt Regency), if not sooner in the forum on the group's new website at www.7fusers.org.

Machining might be best option for removing R0 blades to avoid damaging the wheel. One user provided a short presentation on the care required to remove compressor blades without galling. Ice damage on one of his units, initiated by cooling-tower drift, dictated the removal of R0 blades for repairs.

A 1-ton come-along and air hammer were the tools selected for the extraction which proved particularly difficult, galling 17 blades in the process. The high edges on the gall were blended to get the machine back into operation. Replacement of the first-stage wheel and R0 blades is scheduled for next year. This plant online water washes daily, offline twice annually.

Follow-on discussion revealed that a leaking wash-water valve (with the pump off) was the underlying cause of icing at another plant. In addition, a user attested to the difficulties one can face trying to remove R0 blades. He recommended machining out blades to avoid ruining the first wheel and having to replace it at significant cost. The attendee said it took two days of around-the-clock effort to machine out the R0 blades on his engine.

Discussion highlights:

- Most packages the OEM has are for the flared fleet, not unflared units. Example: There are no Package 2s for unflared units.
- Question to attendees: Any experience with OEM's new Enhanced Compressor? One user reported having a problem-free 8000 hours on one engine.
- R0 dovetail indications building, a user reported. Be prepared for "discovery," he said. Continuing, he suggested to colleagues that they not get complacent regarding inspection. "As the fleet ages, people who never found any indications are now finding them."
- Bigfoot mod: Stator twisting in the case slot occurs early and appears to slow/stop. Future impact, if any, is unknown. More than 60 mods have been installed in the fleet, according to one user, and all show signs of twisting. The OEM reportedly has told users that twisting does not impact performance or reliability. It was said that no plant has yet removed stator blades from a unit with a Bigfoot mod.
- An attendee suggested that users look for cracking on the R17 wheel rim; about half a dozen users said they had found it. Recall that the 17th stage incorporates the stub shaft.

  Another participant said cracking is expected by the OEM and the wheel is designed to accommodate small cracks (up to 0.125 in.), which can be blended out. However, if you blend and can't remove the crack, that user said the crack will propagate faster than if no blending had been done.
- Another user said there also are cracks on R14, R15, and R16 wheels, but they generally are not visible to the naked eye. These cracks are said to run inward from either the front or back face of a disk. You don't know how deep these cracks are until you grind them out. It was said that no failures have been attributed to this type of cracking, "so don't worry about it."
- Audience poll: One user still is operating with P-cut blades.
- Make sure R0 blades are properly staked. Over-staking, it was said, can compromise the ability of a biscuit to lock a blade in place.

Air inlet house

A fire that consumed an inlet filter house pointed to shortcomings in plant's safety plan.

A contractor hired to install prefilters selected a halogen lamp to provide more light in the narrow passageway between the prefilters and conical/cylindrical final filters. An extension cord, draped over the access-door threshold, brought power to the lamp, located about 5 ft inside the door.

Unsafe work practice #1: Never run electrical cords, hoses for cutting torches, welding cables, etc, through open doorways. The contract crew said the door had been wired open, but photos suggested otherwise. Workers took a break and left the light on, then decided to quit for the day because job progress was ahead of schedule.

Unsafe work practice #2: This unplanned work stoppage was not reported to responsible plant personnel and the light remained on. The high heat produced by the halogen lamp ignited combustible material in the inlet house and smoke poured out from the structure. The fire was promptly reported to the control room and emergency procedures were enacted.

Volunteer firefighters arrived within about 20 minutes and took about three-quarters of an hour to extinguish the fire, even though about 80% of the "fuel" had been consumed before the firefighters arrived. The inlet filter assembly and transition duct were a total loss. The support structure suffered no fire damage; silencer panels, inlet-bleed-heat components, and downstream ductwork were salvageable after a thorough cleaning.

Unsafe work practice #3: The danger of halogen lamps and the OEM's recommendation not to use them was covered by Technical Information Letter 1368-2 but went unheeded. Read and understand all TILs recommended for your units and act accordingly, the speaker urged. This same TIL suggested warning/caution signs on the dangers of working in the inlet air house, but they were not posted. Not surprisingly, the Job Hazard Analysis developed for this project by plant personnel never warned of fire hazards.

Unsafe work practice #4: The safety analysis conducted by company personnel after the fire revealed that the lone door in the filter house accessed the lowest catwalk for the filter assembly. The three catwalks at higher elevations were accessible only by ladder. Had there been workers at one or more of the higher elevations when the fire began, they probably would not have survived. Egress panels were installed at each of the catwalk levels. The replacement inlet air house was installed without lighting; plans are in place to add retractable LED lighting.

A key take-away from this incident was that you cannot over-communicate about safe work practices, proper tool selection, and hazardous conditions. The speaker suggested that his colleagues implement a "Friendly Eyes" program if they didn't already have one. It involves taking experienced, safety-conscious employees from another site and have them walk-down your plant to identify unsafe work practices. They will find things the resident employees see regularly and accept, but which may not be in the best interests of health and safety.

Combustion dynamics

The user controls expert who last year offered an objective evaluation on the pros and cons of combustion dynamics monitoring systems (CDMS) installed on 7F engines in the fleet he serves returned to the podium in San Antonio. The speaker said he believes the following three CDM systems are acceptable for powerplant use:

- PSM's AutoTune.
- WoodGroup's (Gas Turbine Efficiency last year) Ecomax™.
- The OEM's OpFlex™ AutoTune.

Last year most of the engineer's experience was with AutoTune; only two engines had been equipped with Ecomax. OpFlex was not considered for deployment because of its cost. What a difference a year makes: Here are the highlights of what he had to say in San Antonio:

- PSM's AutoTune now has more than 30,000 hours of operating experience in his fleet. Recent upgrades included firing-temperature optimization up to 2420F (going higher still this summer) and an events counter for reporting how many times the system has tuned and what's been tuned.
- GE's OpFlex now is offered at various levels to suit specific requirements and pocketbooks.
- Ecomax has been commissioned on six engines in the speaker's fleet with six more being installed. Experience is now coming in from more than 16 units. He reported the following:
- The system is user configurable and offers control-curve optimization—that is, it optimizes base-load output.
- Post-outage tuning is not required.
- Fuel temperature and firing curve knobs are provided to facilitate tuning.
- Operation is flexible. Example: Ecomax will still tune for NO_x when the CDMS is down.
- System's ability to prevent lean blowout (LBO) seems apparent.
- Monthly reports are provided on low-NO_x tuning events that likely have prevented LBO.
- Power optimization is noticeable.
- Installation requires minimal downtime and proceeds in a relatively smooth manner with only minor issues.

Bearing issue

A user offered a step-by-step procedure for installing thermocouples in generator bearings. It was obvious that he hadn't intended becoming an expert on the subject, but when bearings sent out for rebabbiting came back without thermocouples, someone had to install them.

Saving time by doing the job in-house seemed like a reasonable objective. After all, how difficult could the task be? Everyone who has ever spent time on the deck plates knows there's usually more to any job than meets the eye. So it was in this case. You can access the procedure at www.7Fusers.org.

Sensitive rotors

A scholarly, yet practical, presentation by a power-company vibration expert walked users through field data analysis, observations, and conclusions of 7F thermal transient vibration. This is another presentation you may want

3. Protruding S0 shim located between vane segments five and six

4. PSM's R0 retention plug replaces the biscuit familiar to many users

to review at www.7Fusers.org. Perhaps the best part, and critical to easy understanding of the subject matter, is that the speaker prepared an old-school paper (no sketchy PowerPoint), complete with 19 figures.

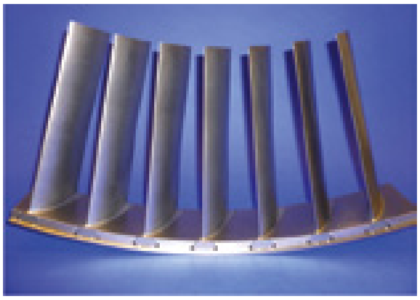
The utility consulting engineer told the group that all rotors have a thermal transient characteristic. For some, the thermal transient can be sufficiently small as to be considered non-existent. On other rotors it can be so severe on a cold start that it can make the rotor go into vibration alarm, cause a load runback based on vibration amplitude, or even cause the unit to trip on vibration amplitude. For most rotors, it is somewhere in between. The source of this transient appears to be a combination of the basic design, manufacturing tolerances, and variations in the assembly process at the factory/shop.

When it has been determined that a rotor has a thermal transient that must be addressed, the expert said, required data should be plotted in polar format for a cold-rotor-condition start, beginning immediately after reaching the full-speed/no-load condition and ending at the steady-state base-load condition. Once a rotor's transient is quantified, a corrective course of action can be determined.

Depending on how the unit will be operated, either tactical balancing or prewarming of the rotor before the actual start usually are the best options. Should the transient's extreme points ever become so large that the transient cannot be controlled—even through warm starts and balancing—then the rotor must be sent to a shop for repair.

Vendor presentations

The vendor community has a great deal to offer gas-turbine owner/operators. Plant and headquarters personnel don't have all the answers, neither do the OEMs. Small businesses serving the electric power industry, in particular, are highly motivated to understand the challenges facing



5. Corrosion-resistant carrier ring segment for S0-S4 is designed for ease of installation and removal

generation O&M personnel: Timely and effective solutions are conducive to a strong bottom line.

Summaries of several 2012 vendor presentations available at www.7Fusers.org are below. Two editors can't get to all of them and, like you, have to make choices.

TIL review

Advanced Turbine Support LLC

When members of the borescope inspection team from Advanced Turbine Support LLC talk, virtually everyone with responsibility for gas-turbine assets pays attention. Reason: Rod Shidler and company generally don't tell you what you want to know, they tell you what you have to know to keep running. Field Service Manager Mike Hoogsteden's presentation to a packed room discussed the importance of technical information letters (TILs) 1509-R3, 1638, and 1795 in reducing operational risks.

Most of what Hoogsteden had to say in San Antonio he and colleague Dustin Irlbeck reported to the industry last December by webinar. CCJ ON*screen's* Scott Schwieger coordinated and produced that event, which was sponsored by Dresser-Rand Turbine Technology Services.

For his 7F presentation, Hoogsteden added a section on TIL 1562 to stress the importance of monitoring the condition of compressor shims and the corrective actions necessary to mitigate the risks of migrating shims on both E- and F-class machines (Fig 3). There are 20 possible shim locations in the first five stages (0-4) of 7F units and they are spaced approximately 60 deg apart from each other.

Most people like stats and Hoogsteden gave the owner/operators some numbers to ponder with what he called the ATS Scorecard. Keep in mind when reviewing these data that, at the time of the 7F meeting, there were said to be 821 engines in the fleet, with the leaders at about 126,000 factored fired hours and about 3500 factored fired starts.

TIL 1509. ATS has completed more than 2000 in-situ inspections since 2001, identifying more than 200 cracked rotor blades, over 70 S0 cracked vanes (six in unflared compressors), and three S1 cracked stator vanes.

TIL 1638. ATS has completed nearly 1100 in-situ inspections of R0 rotor blades (P-cut, standard, and enhanced) over the last five years, identifying 55 R0 blades with cracks adjacent to the P-cut relief, 55 R0 blades with cracks in the suction-side mid-span dovetail fillet, two R0 blades with cracking on the suction-side mid-span dovetail sloped face, two R0 blades with cracks in the pressure-side dovetail fillet (both in the leading and trailing edges), and two cracked R1 rotor blades.

All of the above indications have been validated; there were no false positives.

Compressor solutions, field experience

PSM, an Alstom company

SRO, standing room only, is no surprise when PSM presents at a user group meeting. Chris Johnston, a senior R&D manager, moved quickly through understandable technical detail in bringing users up to date on his company's 7FA compressor solutions and field experience.

Johnston divided the compressor section of his presentation into four parts: R0, S0-S4, S13-16, and S17/EGV (exit guide vanes).

PSM's solutions have been operating in the fleet for four years with parts installed in more than 30 units, he said, adding that fleet-leader sets have been validated by way of on-going in-situ, destructive, and dimensional inspections. The company's redesigned R0 blade, which has a different airfoil shape than the OEM's, is meeting expectations in units that fog and online water wash. Its R0 retention plug replaces the biscuit familiar to many users (Fig 4).

Success with the flared R0 airfoil prompted development of an unflared R0, the R&D manager continued. The new offering also operates without

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Zokman Products Inc

restriction and is now running in four or five engines. The development approach used PSM's successful methodology: field assessment, problem identification, solution implementation, and validation.

S0-S4 field issues, including high-cycle fatigue (HCF) and corrosion concerns, have been addressed with a redesigned S3 airfoil and corrosion resistant carrier ring (Fig 5). Johnston said PSM believes that the OEM's S3 vane has the lowest design margin in this section of the compressor and required redesign to mitigate HCF failures initiating at its leading edge.

OEM vanes in S5-S16 have a history of hook fretting and other hook-fit issues. PSM's S5-S12 vanes remain stator singlets, redesigned to better accommodate the circular case. For rows S13-S16, the company's "hook ring" packed design provides increased damping.

The second part of Johnston's presentation concerned the 7FA GTOP3 upgrade. GTOP is the acronym for Gas Turbine Optimization Program. This enhancement incorporates PSM's low-pressure-drop combustion system and redesigned first- and second-stage HGP buckets and nozzles. The upgraded components have been operating since 2005 and have accumulated nearly 100,000 service hours. They are interchangeable with OEM parts.

The higher firing temperature allowed by the redesigned standard-life (24,000 hours/900 starts) first- and second-stage turbine buckets and nozzles can increase power output of a simple-cycle engine by 5% and improve simple-cycle heat rate by 1.3%, while still achieving less than 9 ppm NO_x and accommodating turn down to 50% of the full-load rating. Extended-life (32,000 hours/1200 starts) airfoils are compatible with a 2% increase in simple-cycle power and a 1% improvement in heat rate.

Johnston noted the 22-MW gain attributed to GTOP3 for the company's first combined-cycle install at a 2 × 1 plant. PSM provided field services, the gas-turbine TFAs, and tuning services. Third-party performance testing conducted before and after the outage validated a 5.2% increase in power for one GT and 5.1% on the other. Efficiency gains were 1.6% and 1.5%, respectively.

Advanced coatings

Praxair Surface Technologies Inc

Don Lemen walked 7F attendees through the company's advanced coating systems for gas-turbine compressors, combustors, and turbine parts. Many participants in the break-out session knew Praxair best for its firtree coating to prevent bucket rock, which is championed at many user-group meetings by Mike Romero.

Lemen began at the compressor inlet with a backgrounder on Praxair's titanium nitride (TiN) solution to help control—possibly eliminate—the liquid droplet erosion of R0 blades associated with both water washing and fogging for power augmentation. Water-jet laboratory testing suggests the company's coating system is good for more than 50,000 hours of service.

If corrosion of compressor airfoils is an issue, Lemen suggested the SermeTel® 5380 DP® coating system, which consists of a closely packed aluminum-filled chromate/phosphate base coat, sealed with a chemically inert chromate phosphate top coat. It is said to protect stainless steel and ferrous alloys at temperatures up to 1200F. On dimensionally critical surfaces, precision coating thicknesses down to 0.3 mils can be achieved.

Zircoat® vertically cracked coatings for combustor parts, buckets, and nozzles requiring the highest level of thermal protection were covered next. The ultra-pure YSZ coating in this family (patent pending) was said to offer long-lived erosion resistance and toughness. A discussion of abrasive tip systems closed out the presentation.

Saluting the 2012 user discussion leaders, speakers

Richard Clark, *Southern California Edison Co*
Dan Giel, *Progress Energy Inc*
Jeff Gillis, *ExxonMobil Chemical*
Ken Gross, *Consolidated Edison Co of NY Inc*
Bob Holm, *OxyChem*
Ben Meissner, *Progress Energy Inc*
Roy Mondy, *Dominion Resources Inc*
Joe Schneider, *NRG Energy Inc*
Peter So, *Calpine Corp*
David Such, *Xcel Energy Inc*
Eugene Szpynda, *New York Power Authority*
Paul White, *Dominion Resources Inc*

Hydrogen control cabinet

Environment One Corp

Many hydrogen-cooled generators—including all those driven by 7F gas turbines—incorporate a scavenging-type seal oil system to prevent the escape of hydrogen from the generator casing and to prevent air from entering the generator case. A critical component in this type of seal oil system is the hydrogen control cabinet. It houses the principal instruments required for supervision of the hydrogen system and the controls for regulating the rate of gas scavenging.

Rob Preusser, manager of utility products and field service, conducted a short course on the company's Dual Hydrogen Control Panel familiar to most who attended the session. By way of background, E/One has more than 1500 hydrogen purity analyzers and 1300 generator condition monitors installed worldwide. Preusser covered a lot of ground in his 40 minutes or so

Vendor presentations available to registered owner/operators at www.7Fusers.org

Advanced Turbine Support LLC, 7FA compressor issues, findings, and inspection techniques. *Rod Shidler*

Dekomte de Temple LLC, Fabric expansion-joint systems for cycling and long life. *Jake Waterhouse*

DNV KEMA, Life management of gas-turbine hot-gas-path components—an OEM independent approach. *Joop Kraijesteijn*

Environment One Corp, Scavenging-type seal systems and hydrogen control cabinets. *Rob Preusser*

ExxonMobil Lubricants & Specialties Co, Developing a low-varnish turbine oil. *Jim Hannon*

Industrial Air Flow Dynamics Inc, GE7FA flex-seal wearing; fatigue warning. *Ryan Sachetti*

National Electric Coil, Considerations in purchasing quality stator winding and rewind. *Howard Moudy*

Pratt & Whitney Power Systems, Breaking down GER3630 repair and replacement cycles. *Andy Lutz and Matt Gartland*

Praxair Surface Technologies Inc, Advanced coating for industrial gas turbines. *Don Lemen*

PSM, Performance and durability upgrade solutions for the 7FA+e gas turbine. *Chris Johnston*

TOPS, Hydrogen seals: Issues and remedies. *Toby Wooster*

Turbine Technology Services Corp/ Rockwell Automation, Maintaining triple modular redundancy with aftermarket, open-architecture control-system upgrades. *Kevin Giroux and Rick McLin*

at the podium, including the following:

- Detailed description of the generator gas analyzer, including physical components and electronics.
- Principles of operation.
- Flow configurations.
- Interface connections.
- Maintenance requirements.
- Troubleshooting.
- Solutions for resolving issues such as oil contamination, failure of power supplies, obsolete circuit boards, etc.

Given the detail of Preusser's presentation you might want to consider using it as the basis for technician training.

Open-architecture control solutions

Turbine Technology Services Inc, Rockwell Automation

TTS is probably recognized best by the greater gas-turbine community for the hundreds of control-systems upgrades it has performed over the years, and by 7F users because of Mitch Cohen's insightful presentations. Kevin Giroux of TTS and Rockwell's Rick McLin brought users up-to-date on open-architecture alternatives for the replacement of ageing 7F control systems—such as the Mark V, which will no longer be supported by the OEM after 2014.

A primary goal of the presentation was to assure owner/operators that the triple modular redundancy feature of the OEM's control systems was also integrated into the open-architecture offering by TTS/Rockwell. Recall that TMR uses two-out-of-three voting to assure a highly reliable control system. Specifically, any single-point failure can be diagnosed and repaired while the system is in operation.

Giroux and McLin also stressed the advantages of open-architecture systems over the "black box" offerings from the OEM, including the following:

- Control code is available and accessible.
- Complete system maintenance is possible. This includes software edits, configuration changes, module additions, etc.
- Ease of integration into other plant-wide systems.

The slides from this presentation are easy to follow and offer a refresher on how triple-modular redundancy works. The PowerPoint certainly is worth a review by users contemplating control-system replacement. Visit www.7Fusers.org.

Varnish no more

ExxonMobil Lubricants & Specialties Co

Jim Hannon of ExxonMobil Lubricants & Specialties Co opened his presentation on the subject of varnish solutions by telling the three dozen attendees in his session things virtually all of them knew: (1) where varnish can be most disruptive and (2) its negative impact in terms of unscheduled outages, extra maintenance, etc. But then he told them something most didn't know: he had the mineral-oil solution that could cure their pain.

Hannon is an old "plant guy" who knows his equipment. He took that knowledge to Exxon where he learned lube-oil technology and became a solutions provider. Most of his presentation concerned how the company went about developing and validating the effectiveness of Mobil DTE 932 GT, which was formulated specifically for GE Frame 6, 7, and 9 applications where varnish control in the hydraulic system is most needed. An independent study of nearly 200 generating facilities powered by more than 600 7EAs and 7FAs revealed that 40% of the gas turbines surveyed had experienced, or were experiencing, varnish issues.

Much of the material presented by Hannon is available in "Vanquish varnish to improve gas-turbine reliability," which appeared in the CCJ's 2011 Outage Handbook. A bar chart included in his presentation showed how well DTE 932 stacks up against the competition based on proprietary rig-test evaluations conducted by ExxonMobil Research & Engineering Co. To dig deeper, access the presentation at www.7Fusers.org.

Generator rewind

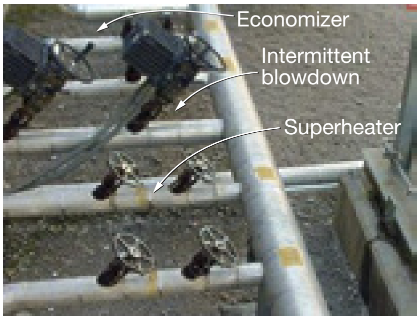
National Electric Coil

If the gas-turbine user group community were to vote for a generator champion, National Electric Coil's Howard Moudy would probably win hands down. Well known, he attends most user meetings and speaks passionately on the maintenance and overhaul of these vital rotating machines. Moudy's presentation at 7F XXI was on "Considerations in purchasing quality stator windings and rewinds."

His goal was to provide much needed perspective on what steps owner/operators should take to assure that their project expectations will be met. The specification is critical, he stressed, and challenged attendees to think about the possible improvements they could make by not replacing in-kind. All capable suppliers have the engineering ability to upgrade an existing coil, Moudy said. For example, thin insulation material available today allows you to increase the amount of copper in an old machine, reducing I^2R losses; thinner strands can reduce eddy current losses.

His slides walked the users through the coil manufacturing process, covering types of ground insulation, winding fit-up inspections, etc. Tests described included blackout, corona camera examination, hi pot, voltage endurance, and thermal cycling. CCJ

Mitigate fatigue cracking in HRSGs



1. Poorly designed drain arrangement has manually operated undersize drain lines and multiple drains ganged together

The half-day HRSG Spotlight Session that HRST Inc, Eden Prairie, Minn, has conducted in conjunction with the 7F Users Group meeting for the last several years is designed for plant personnel who want a refresher on heat-recovery steam generators and an update on industry concerns with large triple-pressure units.

Focus of the 2012 workshop was fatigue cracking, with Amy Sieben, PE, presenting on failures in superheater/reheaters and panelized economizers, and Scott Wambeke, PE, addressing drum-nozzle cracking and fatigue in return-bend economizers. Sieben opened the session by saying that fatigue cracking is one of five mechanisms that account for more 90% of all pressure-part failures suffered by HRSGs. The others are flow-accelerated corrosion (FAC), corrosion fatigue, chemical attack/under-deposit corrosion, and dew-point corrosion.

Fatigue cracking occurs, she said, when material is repeatedly stressed beyond its yield point. Low-cycle fatigue is the term used to describe fatigue failures that occur in fewer than 1000 cycles. Sieben introduced an important term into the lexicon of many attendees when she stressed the importance of managing the HRSG's "fatigue bank account." Fatigue cracking can initiate on the inside or outside surfaces of pressure parts, the boiler designer continued, noting the three components of fatigue: pressure, temperature, and external piping stress.

Superheaters, reheaters

Tube-to-tube temperature differences cause cracking in superheater and reheater panels for two primary reasons:

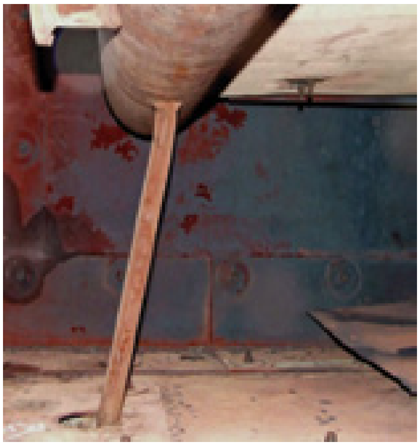
- Condensate blockage and poor drain design. Inability to remove condensate in timely fashion during/following a unit purge often is traced to undersize, ganged, or closed drains.
- Water introduced through interstage desuperheaters, which are located between the primary and secondary superheaters and reheaters. Typical causes include leaking spray-water supply valves, hunting, poor piping arrangements, overspray, and a primary/secondary superheater (or reheater) surface arrangement that is incompatible with a given turbine's performance at startup or low load.

Note that attemperators sometimes are installed downstream of the final superheater or reheater surface in lieu of, or in conjunction with, an interstage desuperheater. Two concerns shared by owner/operators regarding the use of "downstream" attemperators: (1) Additional cost and (2) the risk of steam turbine damage in the event of a failure.

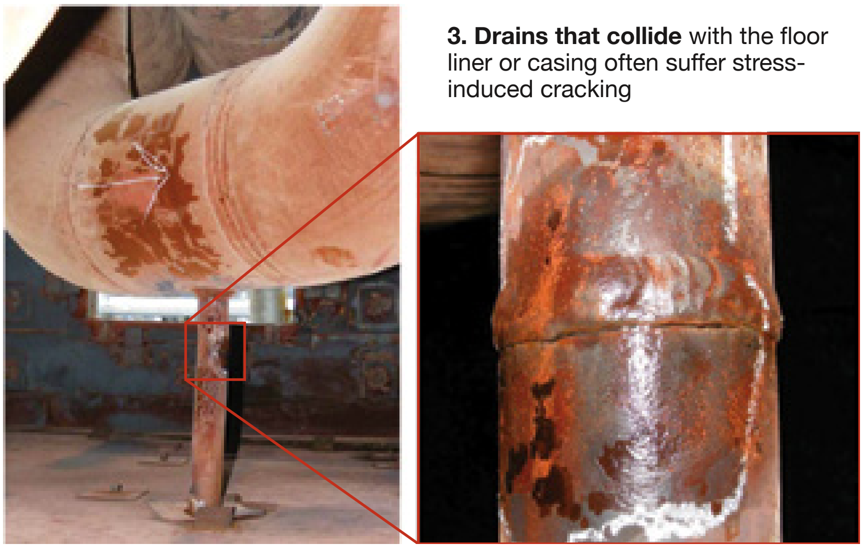
A couple of slides illustrated for first timers the two basic types of desuperheaters used in HRSGs: (1) Probe style with single- or multi-nozzle axial injection and single- or multi-nozzle radial injection. Reported advantages of the latter are that spray nozzles are not in the steam path and steam/water mixing generally is more efficient than with the probe style attemperator (see article, p 98).

Sieben then expanded her coverage of the two bullet points above. She began with a few photos and drawings illustrating how humping of lower headers equipped only with center drains can allow condensate to block tubes at the ends of superheater and reheater panels and cause buckling of those tubes. Having multiple drain locations is one way to solve this problem. Discussion of the dos and don'ts of drain system design came next. Here are the important take-aways:

- Purge condensate from lower headers before every start. Automatic valves are needed to do this effectively.



2. Differential expansion amplifies drain lateral displacement



3. Drains that collide with the floor liner or casing often suffer stress-induced cracking

- Drain condensate as it forms during the gas-turbine purge cycle.
- Proper sizing of drains is critical. Keep in mind that drains too large or too small can be problematic.
- Locate blowdown tanks below header drain locations.
- Avoid combining drains (Fig 1). Be especially careful not to interconnect drains operating at different pressures: The higher pressure drain can block condensate flow from the lower-pressure line.

Sieben next noted that a proper drain must allow for a full range of motion between the penetration seal and the access hole in the HRSG casing. Differential expansion amplifies drain lateral displacement, she said, illustrating the point with Fig 2. Drains that collide with the floor liner or casing often suffer stress-induced cracking (Fig 3).

Ineffective draining of cold reheat lines, and occasionally main steam piping, also is conducive to damage. Sieben spoke about water hammer resulting from a slug of condensate being pushed through steam piping during startup. Typically, she said, pipe supports are bent, or thrown out of position; piping may be damaged as well. Tube damage is a possibility, too, if a slug of water reaches the HRSG. Sieben offered a checklist on how to avoid water hammer:

- Drain steam piping before every gas-turbine start. Best practice: Automate valves and install condensate detection for added protection.
- Confirm piping slope and the ability of the drain system to clear condensate from the entire line.
- Prevent the possibility of water accumulation upstream of valves—especially the steam-turbine bypass.
- Tightly control bypass/letdown valve attemperation.
- Check for leaking attemperator spray water.

Before addressing in detail the desuperheater problems identified earlier, Sieben reminded attendees of recent changes to the *ASME Boiler & Pressure Vessel Code* regarding attemperators. First, drain pots downstream of desuperheaters must be able to detect water automatically and to drain it without operator intervention. Second, superheater and reheater drains must be able to detect and drain condensate both under pressure and at atmospheric pressure.

Leakage by block and control valves usually can be prevented, Sieben added, sometimes by simply specifying Class V shutoff or better. Confirm leak tightness by finding no drop in steam temperature across the desuperheater. Attemperator hunting, most common at low load, causes chronic cycling with the possibility of fatigue damage in the probe, liner, and/or piping. Hunting increases the likelihood of finding water in the superheater.

Attemperator overspray can damage superheaters and reheaters, and, in the case of desuperheaters downstream of those heat-transfer surfaces, may cause catastrophic damage to the steam turbine. Overspray usually is attributed to one or more of the following conditions:

- Poor atomization of spray water because of probe/nozzle damage or partial plugging.
- Improper piping design—in particular an insufficient straight run of pipe upstream and/or downstream of the attemperator.
- An arrangement of superheater and/or reheater surface that allows overspray to occur at some operating points (typically startup or low load) because all the water cannot be evaporated.

Sieben spent several minutes explaining the last point by way of diagrams with actual gas and steam temperatures and spray-water flow rates for varying loads both with and without supplementary firing, and for different ratios of superheater and reheater primary and secondary surface.

One example presented: A superheater for an F-class HRSG designed with 60% primary surface area and 40% secondary surface area requires no spray water when operating at base load without duct burners in service, but needs 43,000 lb/hr of spray water at min load with supplemental firing. For a superheater having 70% of its surface area in the secondary bundle, 55,000 lb/hr of spray water would be required at min load without duct burners.

Correcting for overspray can be extremely challenging and expensive, Sieben continued. Options she offered included these:

- Bypass a portion of the HP saturated steam flowing from the drum to the primary superheater thereby cooling steam exiting the secondary superheater. Same logic can be applied to the reheat circuit, with some of the cold reheat steam being withdrawn ahead of the heat-transfer surface to cool hot reheat. This option is rarely practical because of the expense involved and because reducing steam flow to superheater/reheater panels can increase metal temperatures above recommended limits.
- If too much surface is installed, remove fins and/or gas baffles, or use tube shields, to reduce heat transfer.
- Add a final attemperator or an additional interstage desuperheater.
- Minimize or eliminate the need for spray water on startup by installing an air attemperation system.

Economizers: panelized, return-bend

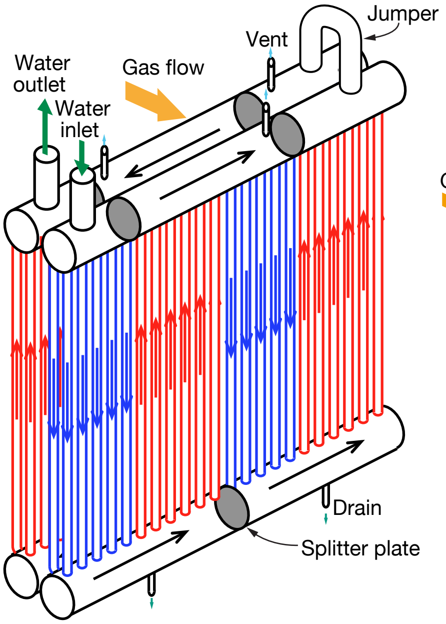
In panel-type economizers, Sieben said, water goes up and down in each panel, or harp, making from two to six passes depending on the number of baffles or splitter plates installed in the upper and lower headers (Fig 4). There are from one to three rows of tubes per panel. Return-bend economizers usually have alternating upflow and downflow tubes in the same row (Fig 5). In some cases, water flows up one row, down the next—a serpentine arrangement. High points in return-bend economizers typically cannot be vented, which can be problematic under certain operating conditions.

Thermal shock. Sieben said that, depending on panel geometry, a temperature differential between tube rows of from 30 to 100 deg F can cause thermal shock, which contributes to fatigue failure. Such a differential can occur in headered-economizer inlet passes, and in the upper bends of return-bend economizers, at top-off or startup. The boiler engineer explained: During startup, operators expect drum level to swell and the feedwater control valve is closed; no water is flowing through the boiler. During this time, economizer panels "soak" to temperatures higher than normal.

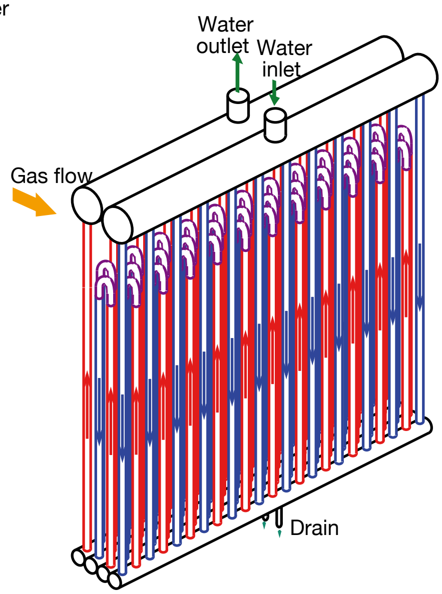
When HP drum level finally starts to drop, the feedwater control valve opens and "cold" water "shocks" the economizer (see article, p 74). Recall that economizer tubes have rigid connections at both ends and high tensile stresses result when panels are shocked. Tube leaks often result at tube-to-header welds. Similar or worse shock can occur when adding water to an economizer during overnight shutdowns. Sieben strongly suggested that operators resist the temptation to do so, even if the water level drops to the bottom of the gauge glass. No heat is being added to the HRSG, she said, so this is not a problem.

Sieben then offered the following operational guidelines to minimize the possibility of thermal shock:

- Trickle-feed water through the HP economizer as soon as drum pressure begins to increase.
- Assure positive feedwater flow



4. In panel-type economizers, water goes up and down in each panel



5. Return-bend economizers usually have alternating upflow and downflow tubes in the same row

thoughout the startup period. A small startup control valve may help because the main feedwater control valve installed should not be throttled below its minimum position of 5% to 10% open. A startup valve can be retrofitted in parallel with the main valve to handle low flows.

- Start the main boiler-feed pump when HP drum pressure begins to increase and blow down as needed to control drum level. Important: Do not stop water flow once started; that would initiate another thermal-shock event. Damage from such events is cumulative.

Buoyancy instability. Sieben moved on to two other fatigue mechanisms: buoyancy instability and steaming economizers. In explaining the first phenomenon, she reminded that warm water is less dense than cold and wants to rise, and that most HRSG economizers have a portion of their tubes that flow down.

If the downward velocity is too low, the buoyancy of warm water can cause flow stagnation in down-flow tubes. In extreme cases, flow may actually reverse. Such instability reduces economizer heat transfer, adversely impacting performance. More importantly, tubes experiencing stagnant and reverse flow become hotter than neighboring tubes. The level of stress increases in these tubes, in particular at reduced loads when fluid flow is low. Hundreds of thermal cycles can occur daily, leading to fatigue failures.

Buoyancy is a design issue, Sieben continued, that can result in some tubes being from 30 to 60 deg F hotter than adjacent tubes—not a good situation. Damage caused by buoyancy issues sometimes can be mitigated by modifying the flow circuitry of pressure parts. Adding a recirculation circuit to the economizer is another possible solution.

Increased fluid velocity can overcome buoyancy instability. Rearranging baffle plates in headers may correct the situation, but this could be costly and require significant outage time. Testing and engineering analysis may indicate certain operating loads where buoyancy issues are especially problematic. Perhaps operation at these loads can be avoided, or at least minimized.

Economizers often steam during startup, and when operating at low load without duct burners in service. Steaming can cause vapor lock and flow stagnation. In some cases, the pockets of steam are pushed through a boiler's fluid circuitry by water flow when the unit reaches full load. Vents can eliminate steam pockets in panelized economizers, Sieben said, but this would require too many manual vent valves. In return-bend economizers, "surging" feedwater flow may clear steaming or buoyancy-instability issues.

If your economizer is steaming at base load, Sieben told the group, one of these three conditions probably exists:

- Design water-outlet temperature is too close to saturation—that is, the approach is too small.
- The economizer bypass is not operating properly or it is underdesigned for the service.
- Under-performance of upstream (with respect to gas flow) heat-transfer sections.

Return-bend economizers

Regarding return-bend economizers, Wambeke had these comments on thermal shock:

- Ability to withstand thermal shock well.
- A few plants have reported tube cracking or flattening of return bends at the top of the bundle.
- Maintaining slow flow during startup helps to mitigate vapor locking and reduces the risk of other problems.

Wambeke said buoyancy instability is difficult to correct in this type of economizer. It causes flow stagnation in downflow tubes, which run hotter than upflow tubes. Serpentine return-bend designs are most susceptible to this problem. Steaming in a return bend may create a trapped steam pocket that is very difficult to clear.

ShockMaster® economizer

If economizer issues cannot be managed successfully using any of the solutions mentioned above, Wambeke suggested that owner/operators consider replacing their existing economizers with HRST's ShockMaster. The defining feature of the ShockMaster is that water flow is upward through all tubes. Water collected in the upper header of one panel flows by way of a downcomer to the lower header of the next harp in the series. Sufficient flexibility is designed into the piping system to accommodate panel-to-panel differential growth—even during startup "thermal shock" conditions.

With upward flow, Wambeke continued, buoyancy forces are in the same direction as fluid flow, which is conducive to uniform flow through all tubes in a given bundle. Because each panel is single-pass, all tubes at nearly the same temperature there is no possibility of buoyancy instability. To date, HRST has done three conversions and provided ShockMasters for four new units. The new product can be incorporated into any manufacturer's HRSG, the boiler designer said.

Steam-drum nozzles

Wambeke's presentation on steam-drum nozzle cracking covered much of the same ground as HRST's Bryan Craig, PE, did at last year's HRSG Spotlight Session for 7F users. But given industry concerns with nozzle cracking, this year's presentation provided guidance on what to do if damage is identified and offered lessons learned from two recent experiences. If cracks are found, Wambeke suggested that the following steps, among others, be taken:

- Determine the root cause of the cracking.
- Remove existing defects.
- Confirm complete removal of defects with an appropriate method of nondestructive examination (NDE).
- If remaining thickness after excavation is less than that allowed by the *ASME Boiler & Pressure Vessel Code,* weld repair is required. Code calculations using actual drum component thickness can quickly determine the need to weld, or not.
- Prepare the entire weld area to bright metal and perform weld prep.
- If the original code of construction requires post-weld heat treatment (PWHT), review the *National Board Inspection Code* (NBIC) for alternative methods. Wambeke pointed out that for HP drums, the original code of construction likely will require PWHT, which must be done in a band around the drum circumference—typically impractical. It is better to avoid PWHT, he said, than to perform it incorrectly. Alternative methods involve preheat and have restrictions on weld interpass temperatures. Make sure to have an Authorized Inspector onboard with your repair plan *before* starting work.
- Complete the repair using the shielded metal-arc welding process and inspect as necessary.

Case history #1. Cracking of a downcomer nozzle was found during a routine inspection and excavation revealed a crack depth of ½ in. A long, expensive repair was anticipated by the owner. However, ASME Code calculations by HRST engineers showed the drum shell, nozzle, and welds slightly larger than the original specifications, and the remaining thickness after excavation was greater than the Code minimum. The repair was delayed so proper planning and budgeting could be done.

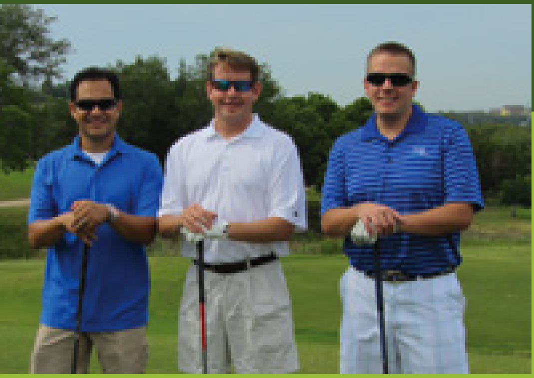
Case history #2. A substantial number of downcomer cracks was found during a routine inspection, leading inspectors to look at risers; 14 of 16 riser nozzles were affected. Repairs could not be delayed in this case.

Wambeke wrapped up his presentation with a list of takeaways from work done thus far on steam-drum nozzle cracking, a common problem in F-class HRSGs. They included the following:

- Driving force is thermal stress caused by startup and shutdown temperature ramps.
- Drum nozzle design is important. Example: Full-penetration nozzle welds are better than partial-penetration welds in cycling service.
- Visual inspection is useful, but not sufficient on its own. You can have cracks and not know it. Surface NDE (dye penetrant, mag particle) is the minimum level of inspection recommended, but volumetric NDE (shear-wave or phased-array ultrasonic testing, radiography) is better still for the additional information it provides.
- Reduce cracking risk by controlling temperature ramp rates, but keep in mind that some details are out of your control.
- Try to find cracks early in their development, before they propagate deep into the weld or drum shell.
- Weld repair, if required, is complex and requires careful planning.
- Inspection is vital if your HP drum wall is thicker than 5 in. and the HRSG has experienced more than 800 starts. Have a repair procedure in place.
- Know the design details of drum nozzles.
- Consider changing weld details before making repairs; there may be substantial benefits. CCJ

1. William Dollard, Will Tribula, Mike Moran, Phil Scott

2. Patrik Allmark, Rick Wilson, John Walsh, Barry Link



5. Americo Zapata, Jody Boyd, Ken Gross

6. Larry Tondre, Adam Wooster, Jake English

7. Orlando Ramos, Brett Crochet, David Bollir

10. James Clark, Matthew Hoyt, Schuyler McElrath, Mike Romero

11. Buzz Wentz, Keith Bosheers, Paul Dumke

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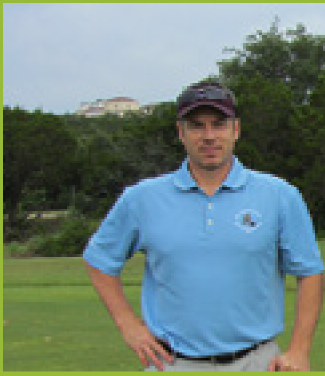
Zokman Products

Scoreboard

Rank	Score	Team
1	61	Robert May, Wiley Schenk, Darren Legg, Mike Thawley
2	63	John Walsh, Barry Link, Rick Wilson, Patrik Allmark
3	64	Brian Hall, Eamonn Rogers, Jeff Chapin, David Lawrence



Longest Drives
Hole #1. Dave Brunson
Hole #5. Emilio Escalante
Hole #14. Joe Smith

Closest to pin
Toby Wooster

Straightest Drive
Will Tribula

3. Eamonn Rogers, Brian Hall, David Lawrence, Jeff Chapin

4. Todd Dunlop, Toby Wooster, James Henry

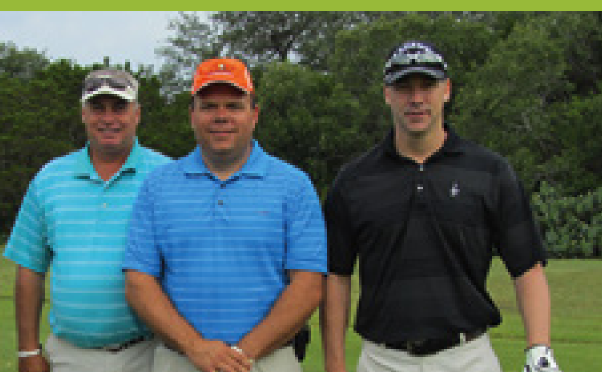
nger, Richard Olejnik

8. Steve Wenger, Richard Clark, Andy Baxter, Peter So

9. Gary Ratliff, Dion Beckner, Lee Wood, Larry Oberacker

12. Vince Hilaire, Jared Nelson, Mike Easton, Bill Shama

13. Chris Green, Dave Brunson, Jason Brown



14. Tim Shippy, Ronnie Hudgens, Bob Renaud, Mike England

15. Ross Rolle, Lew Archer, Steven Jones, Kevin Kennedy

A cornucopia of information, the ideal meeting for time-challenged managers

The CTOTF™ Leadership Committee, chaired by Bob Kirn of TVA, consistently delivers on its promise to provide coverage of the entire plant at each of the organization's semiannual meetings. At the user group's four-day Spring Turbine Users Conference last April in Virginia's Williamsburg Lodge, 17 interactive user sessions totaling 67 hours of presentation and discussion time took the more than 100 plant and asset managers in attendance from the gas transmission line to the plant's connection to the high-voltage grid. Key points from these sessions are summarized below.

In addition to sessions dedicated to specific types of gas turbines, other critical equipment, industry issues, O&M and business practices, and regulatory and compliance matters, the meeting featured several special events, including the following:

- Presentation of the 2012 Best Practices Awards recognizing the valuable contributions made by plant staffs—and headquarters personnel—to improve the performance of generating facilities powered by gas turbines (details in companion article, p 94).
- A trade show involving more than five dozen companies that offer equipment and services to generating stations.
- CT-Tech™, an additional training opportunity offered by CTOTF, provided expanded instruction on contamination solutions for gas-turbine lube and hydraulic systems. The three-hour evening program was conducted by subject-matter experts from Hy-Pro Filtration.
- A tour of Alstom's rotor overhaul shop in Richmond (sidebar).

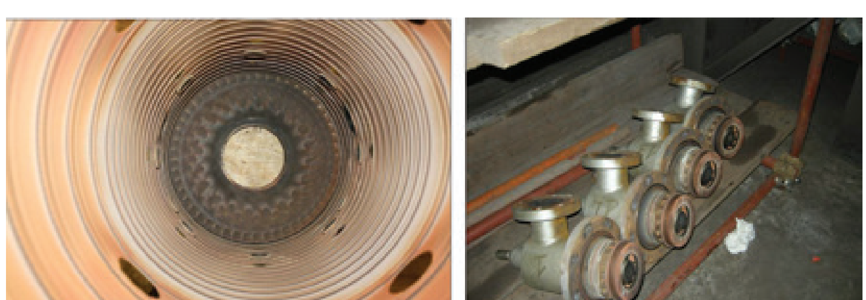
GE F-class engines

A properly operating combustion system is critical for achieving desired gas turbine performance while maintaining pollutant emissions at or below permit limits. That's certainly not news, but many people with responsible deck-plates positions who came into the industry after the millennium are not fully aware of how challenging it can be to keep a late-model F-class engine "tuned" to meet expectations and why this is so.

Robert Bland, chief design engineer for Wood Group GTS's Combustion Engineering Systems and Technology Solutions group, provided a backgrounder on dry, low-NO_x (DLN) combustion to help users make better O&M decisions. The combustion expert shared his knowledge with owner/operators attending CTOTF's GE F-class roundtable. Pierre Boehler of GenOn Energy Inc and Mike Hartsig of NAES/Griffith Energy are the chair and vice chair, respectively, of this popular session, which is featured at the organization's spring and fall meetings.

CTOTF normally restricts presentations by non-users to 30 minutes or less, but it set aside two hours for Bland's "DLN2 Combustion Configurations" and follow-on discussion because of the subject's importance to attendees. Bland was equal to the task and with his depth of knowledge easily could have conducted a full-day workshop. The combustion expert moved quickly though a mountain of information contained in about five dozen slides, taking questions at the convenience of attendees.

Participants who knew the most about the subject matter probably benefitted the most given Bland's word speed. His PowerPoint is posted to CTOTF's extensive Presentations Library at www.ctotf.org, enabling users who were unable to attend the meeting to benefit from its extensive content. If you have not yet registered for the CTOTF Presentations Library, do so today online—it's a simple process. The primary requirement: You must be employed by an owner/operator of gas turbines.



1. The road to DLN2 began with a single-nozzle conventional combustor—simple, inexpensive, robust. Water or steam was used for NO_x suppression

Bland began at the beginning, tracing the birth of NO_x control in gas turbines back to the early 1970s in Southern California. He seemed to leave no stone unturned, explaining how NO_x is formed and how it was controlled prior to the development of DLN combustion systems—by quenching the flame with water or steam. This was a suitable approach initially, he said, because a water-to-fuel ratio of 0.5 could reduce NO_x emissions on an oil-fired unit to about 75 ppm.

But California demanded still lower emissions. By the end of the 1970s, a water-to-steam ratio of 1 was required to reduce NO_x to the 42 ppm on gas required in some areas. Such a significant amount of water or steam can adversely impact combustor performance and economics, Bland noted. For example, CO discharges and combustion dynamics increase and the cost of treated water, which cannot be recovered, reduces profitability.

2. Multi-nozzle conventional combustor was developed to reduce levels of combustor noise as firing temperatures increased

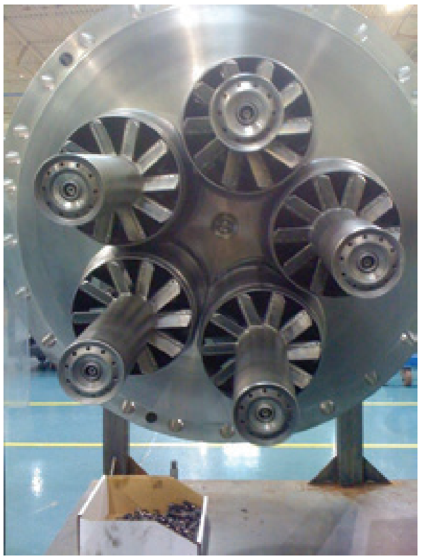
3. DLN1 was the next step: A secondary nozzle was added. It is capable of achieving 25 ppm NO_x or less in E-class applications

Engineers believed that the diffusion-flame combustion systems in use at the time (Figs 1, 2) were in conflict with the goal of lower emissions and supported switching to a premixed flame. Recall that the diffusion flame gets its name from the process by which air (oxygen) combines with the fuel (by diffusion); a premixed flame is one where oxygen and fuel combine before the mixture reaches the flame front. Premixed flames burn at a lower temperature than diffusion flames and therefore produce less NO_x.

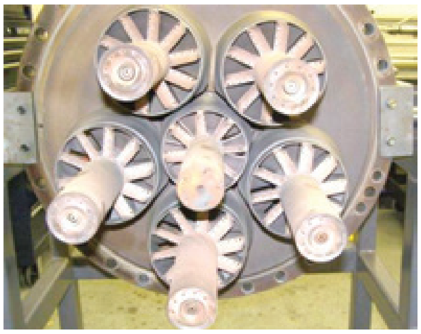
Discussion of the DLN1 series of premixed combustion systems (Fig 3) installed on GE 6Bs, 7EAs, and 9EAs—and early 7FAs and 9FAs as well—was a good segue to the DLN2 family for the OEM's 6, 7, and 9 FAs and FBs. The first combustors in this series were called DLN2 (Fig 4), followed by DLN2+, and later by DLN2.6+ (Fig 5). Bland told the users not to think that combustors with the same model number are necessarily the same. They may look the same, he said, but they can differ with frame type, year of commissioning, and other factors.

It's difficult to design an optimal combustion system to suit an entire series of engines, the expert continued. Reasons include (1) the design of engines in a given model series varies over time based on operating experience, (2) today's replacement hardware may be different than the parts installed during the last overhaul, (3) operating paradigm can change over time, etc. Additionally, consider that the combustion system installed in your new turbine probably is designed for 12,000 hours or longer. You make adjustments three or four years later during the first hot-gas-path inspection and then you're back in service for another three or four years before you see if what you did corrected previous issues.

Bland then dug into the details of the DLN2, 2+, and 2.6+ to show attendees how the combustion sys-



4. DLN2 was introduced on the 7FA (model 7221) as a 25-ppm-NO_x combustion system. Note the ring of five nozzles, no center nozzle. This system was replaced by the DLN2+ before the millennium



5. DLN2.6, a 15-ppm solution, first shipped on the 7231. Turbine redesign enabled the same basic system to achieve 9 ppm on the 7241 (7FA+e)

tem evolved. For example, the DLN2 was introduced on the 7FA (7221) in 1994 as a 25-ppm system. It was last installed in 1999. There were infant mortality issues to be sure—including dynamics so severe the system sometimes wouldn't operate during trials, flashbacks into the premixer, etc. The five-nozzle DLN2 was modified by addition of a center nozzle to DLN2.6, first installed on a 7FA+ (7231) to reduce NO_x emissions to 15 ppm.

Turbine redesign, which released more air to the combustor and reduced combustor pressure drop, enabled the DLN2.6 to limit NO_x emissions to 9 ppm for the 7FA+e (7241) engine. For background on the DLN2.6 and its operation, access "Preventing blowout trips of 7FAs" in the **CCJ's** 3Q/2011 issue at www.ccj-online.com.

The second half of Bland's presentation focused primarily on a detailed review of major DLN2.6 components—for example, end cover, flow sleeve, fuel nozzles, quaternary fuel, cap, Swozzle premix fuel nozzles, liner, crossfire tubes, and transition piece. Included was a rich discussion of operational issues—such as braze failures that can allow fuel to leak the face of the end cover—and how to repair same. Guidance also was provided on how many times a given repair could be made.

The final day

CTOTF lumps generators, high-voltage electrical, and I&C presentations and discussions into what it calls the Gen-EI&C Roundtable, which traditionally runs from 8 am to 4:30 pm on the final day (Thursday) of each meeting. SRP's Moh Saleh is the chairman of this session, doubling as the chair of the high-voltage (HV) component; John-Erik Nelson, Braintree (Mass) Electric Light Dept, is the I&C chair and Craig Courter, Guadalupe Power Partners/ NAES, is the generator chair.

Two presentations at the spring meeting receiving high marks from attendees were John Blaney's, on wireless applications in power, and Paul Griffin's, on mitigating the risk of a transformer failure. Blaney is a technology leader in Emerson Process Management's Power & Water Solutions group; Griffin is VP of power services for Doble Engineering Co, specialists in condition assessment and monitoring of transformers, HV switchgear, and generators.

No wires, no limits. In the generation sector of the electric power industry, John Blaney may be the most passionate supporter of wireless communications networks. The controls expert got the session moving on a high note with an entertaining, but serious, technical backgrounder on wireless communications and an overview of the technology's future. Blaney, who has more than three decades of experience designing, installing, and troubleshooting powerplant control systems, is Emerson Process Management's point person on PlantWeb® applications for the company's Ovation® platform.

Blaney's mission was to get the group to kick back and think of the benefits associated with extending the reach of the plant network using wireless technology. Wireless networks, he said, can be characterized as either field or plant networks. Each serves different applications and has specific requirements for bandwith, power, and standards.

Field networks, formed by wireless field devices and gateways, are configured for process applications, process control, and diagnostics. Typical applications include monitoring of (1) stacks and vents to avoid fines for exceeding permitted limits of pollutants and (2) valve position to ensure equipment is properly aligned.

He told the group that wireless technology has matured from the point-to-point field networks that some attendees recalled as having limited reliability to self-organizing networks, commonly referred to as "meshes," available as a process industry standard through the HART Communication Foundation. Self-organizing networks are the only industry standard available today, Blaney continued, because they are the only ones capable of providing the reliability of data transmission required for power and process applications.

The ability of self-organizing networks to automatically reroute data to an open frequency/channel, and to the most efficient device for communications, enables data transfer reliabilities of more than 99% regardless of process environment or application, he said—adding that the WirelessHART network automatically adjusts to satisfy plant requirements as your environment and network changes.

The wireless champion pointed out that while it may seem counterintuitive, self-organizing networks become stronger with each device added because the number of communication paths increases. You use wireless, he said, but you don't have to fully understand it to use it. The WirelessHART experience base currently spans 2500 sites worldwide with more than 300 million hours of operating time in real applications.

Security probably was on the mind of virtually every owner/operator in the room given NERC's (North American Electric Reliability Corp) emphasis on that subject today. Blaney reported that WirelessHART integrates best-in-class security to protect wireless networks from outside threats. Also, that Emerson's security approach has been validated and tested by customers and wireless experts. Here are the key elements of the WirelessHART approach to security:

- Data encryption to protect valuable information.
- Ability to authenticate sender and receiver to ensure that only devices within the network communicate with each other.
- Ability to verify that the data have not been changed during transmission.
- Anti-jamming technology, specifically channel-hopping, to avoid interference and improve reliability.
- Automatic key rotation (password management) to protect your network from unauthorized access.

PSM overhauls its first F-class rotor in Alstom's Willis Rd shop

PSM continues to reinvent itself and add new services. The company's field engineers and craftsmen recently removed a damaged rotor from a 7FA in base-load service and shipped it to parent Alstom's turbine and generator repair facility near Richmond where PSM destacked its first compressor. The Jupiter (Fla) firm, known best for its capabilities in the manufacture and repair of critical industrial gas-turbine components, also is developing a rotor life extension program.

Alstom hosted a shop tour and dinner for GT owner/operators attending CTOTF's Spring Turbine Users Conference. The group had the opportunity to inspect the debladed wheels before reassembly began.

CTOTF attendees were told that the unit started commercial operation in 2004 and had accumulated about 56,000 operating hours before the 6 o'clock S1 vane failed and its tip went downstream, damaging a significant number of rotating and stationary airfoils.

Shortly after the rotor was received at the shop (Fig A), the marriage coupling was broken and the turbine section moved aside for cleaning and the repair of one bucket without destacking (Fig B). Compressor blades were difficult to remove, the tour guide said, requiring cooling and old-fashioned persuasion to accomplish the task. Blades removed, the rotor was disassembled (Fig C).

A. 7FA rotor is received at Alstom shop for repairs

B. Marriage coupling broken, turbine section is prepared for cleaning and the repair of one bucket

C. Compressor section was disassembled after blades were removed

PSM later re-equipped the entire compressor with blades and vanes of its manufacture and having the most advanced features available. For example, all vanes have attachment undercuts to prevent fretting wear and no shims will be used in the unit. In addition, the undamaged R0 stage was rebladed with PSM airfoils that permit unrestricted water washing and fogging without the need for periodic ultrasonic inspections and dental molds. The blades and vanes are designed to serve out the expected remaining life of the unit. The rotor was reassembled using tie and marriage bolts manufactured by PSM. A high-speed balance in the Alstom shop's pit confirmed work quality.

PSM enhancements included the following, moving from the front of the compressor aft:

- Rows S0-S4 have 10 vane segments each with vane carriers made of high-grade stainless steel. Recall that users are generally critical of the OEM's design which has only six vane segments that often become locked in place and cannot be removed without destroying them. PSM says experience shows its vane segments are relatively easy to remove. Also, S0 has one more vane in the lower half of the casing than it does in the top half and S1 one more vane in the top half than the bottom—this to decrease stresses on R1 and R2 blades.
- Rows S5-S12 were assembled using individual vanes with radial hooks to provide smooth contact between the airfoils and the casing.
- Rows S13 through the exit guide vanes (EGV) are comprised of so-called vane packs—groups of four or five airfoils attached together. Number of vanes in a pack depends on the stage. Packs help stabilize vanes in the case and reduce fretting found in many units with individual vanes.

The gateway interface between the wireless field network and the wired network world employs all components of the security solution described above and is responsible for managing security as well. Because the wireless field devices do not use TCP/IP messaging, if an intruder tries to compromise that side of the network, the attempts will be ignored. However, because communication from the gateway to the control system does uses TCP/IP messaging, Emerson relies on industry standard techniques—such as VPN and HTTPS—to assure what the company believes is the most robust wireless security in the industry.

Plant networks. Whereas field networks are used to communicate critical process control information, wireless plant networks serve applications not necessarily central to the basic power-generation process. These include data connectivity, video/perimeter security, voice communication, and people and asset tracking. Plant wireless, Blaney said, relies on commercial off-the-shelf technologies—such as Wi-Fi, which is defined by IEEE 802.11, an accepted industry standard.

Because plant networks use open IT standards, security measures must be added to address evolving concerns. Blaney said this means it's in your best interest to choose a plant network supplier with the capabilities to address the full range of security concerns to the satisfaction of the IT community. Emerson has done many implementa-

6. Current information is critical for identifying problems before they result in failure

tions combining field WirelessHART and plant Wi-Fi networks, he added. Customized solutions are developed to accommodate a specific problem or area of the world.

To dig deeper, access Blaney's "Benefit by installing reliable, secure wireless communications networks at your plant," which appeared in the 2009 Outage Handbook published as part of **CCJ's** 3Q/2008 issue, available at www.ccj-online.com.

Transformers represent one of the largest and most critical investments in an electric power system. Paul Griffin told users that mitigation of failure risk begins with a well-designed, well-built transformer. However, an effective maintenance strategy is critical to maximizing transformer performance and reliability, he said.

An integrated program of online and offline testing, and online monitoring, are an important part of this effort, Griffin added. A good strategy is to determine the potential failure modes and establish a surveillance program using matching diagnostics. Failures of windings, for example, can be caused by excessive heat, age, insulation breakdown, and/or mechanical issues. Overheating attributed to circulating currents, and oil deterioration and contamination, are other known contributors to transformer failure.

Current information is critical for identifying problems before they result in failure (Fig 6). Griffin pointed to the following information resources available to users: external inspection, laboratory and electrical testing, review of unit-specific historical operating data, review of fleet/design-specific data, OEM service advisories, plant trouble and failure reports, plant personnel responsible for HV assets, etc.

He then expanded his discussion on each of these points. For example, on the subject of electrical testing, Griffin reviewed the value of power factor and capacitance measurements, excitation, leakage reactance, frequency response analysis, dc winding resistance, and insulation resistance.

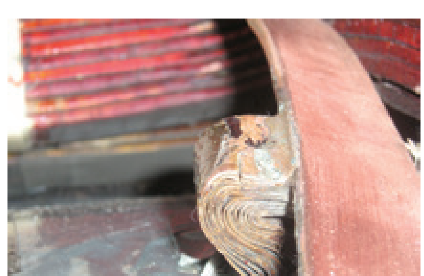
Next, the transformer expert provided a checklist of information required to conduct a detailed condition assessment. This seemed particularly helpful for any attendee assigned to a due diligence team evaluating an asset purchase. Here's what Griffin considers important:

- Data from dissolved gas analysis and other oil tests.
- External inspection.
- Results of electrical tests.
- Type of operation—for example, peaking plant, base load, etc—plus loading profile.
- Age.
- Maintenance and repair records.
- Documentation relating to problems and failures.
- Design review.
- Loading profile.
- Transient fault recording data.
- Acoustic analysis.

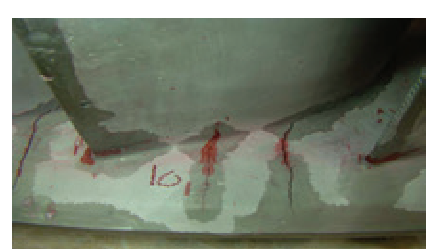
GE legacy gas turbines

Frame 7B-EA engines are thought to be running more because of low gas prices. This made the CTOTF Leadership Committee believe users would benefit from the latest experiences of owner/operators with end-of-life issues, considering the relatively large number of these machines 25 years old and older.

Correct! Attendee interest clearly



7, 8. Slot insulation burn-through (left) and cracking of flex leads resulted from a field ground fault



9. Cracking of first-stage nozzle to the degree shown suggests replacement, not repair

10. Large gaps between third-stage bucket tip shrouds are indicative of loose dovetails

11. Old casings often are damaged during disassembly and reassembly—as these bolts attest

12. Cracking of exhaust-diffuser turning vanes is relatively common in the 7B fleet

was in evidence at the GE Legacy Roundtable, chaired by Pierre Boehler of GenON Energy Inc. Ed Wong of NRG Energy Inc is the vice chair. The user-only discussion that developed from a simple slide with the bullet points below lasted about two hours:

- Generator issues
  Field and stator windings.
- Turbine issues
  Hot-gas-path (HGP) degradation,
  Compressor,
  Casings.
- Balance-of-plant (BOP) issues
  Controls and wiring,
  Piping corrosion,
  Auxiliaries and other.

There was simply too much information on too many topics to summarize in a few words, so the editors just selected a couple of subjects for coverage. Attendees were the big winners, as always at CTOTF meetings, gaining valuable perspective along with a collection of best practices and lessons learned.

Generators. On the subject of generators, one user reported on a 7B field ground fault that occurred a few years ago. A shop visit identified winding coil distortion and slot insulation burn-through (Fig 7), copper migration and deformation, cracking of about half of the main-lead flex leaves (Fig 8), and other issues—generally attributed to age and demanding service. A full rewind and high-speed balance were required before returning the field to the plant.

First-stage nozzles were part of the HGP discussion with another contributor to the collective knowledge sharing his experience with carbide growth at grain boundaries, chrome depletion, internal cracking in air passages, etc (Fig 9). One of his concerns was the increasing cost of repairs.

Second- and third-stage nozzles of FSX-414 were mentioned because of this material's tendency to creep. Distortion can exceed the limits for repairs to correct creep, the group was told. Downstream deflection of second-stage nozzles also generated some discussion. Owner/operators were made aware of the consequences of loose dovetails, including the large tip shroud gaps shown in Fig 10. Fixes discussed for worn dovetails included coatings and tri-seal bucket seal pins.

Users also were reminded of obsolete bucket designs, ones out of production—such as the first-stage "sharp nose" design prone to cracking. Shroud-block degradation was another topic brought to the floor, an attendee relating his experience with extensive cracking of first-stage shrouds and heavy erosion of second- and third-stage blocks.

Casing degradation was of considerable interest to the users. Several mentioned experiences with cast casings heavily degraded from rusting and gouging damage. Substantial material loss was reported in some cases, especially at flange surfaces and bolt and plug threads (Fig 11). It seemed as if every exhaust frame suffered from cracking and repeated weld repairs (Fig 12).

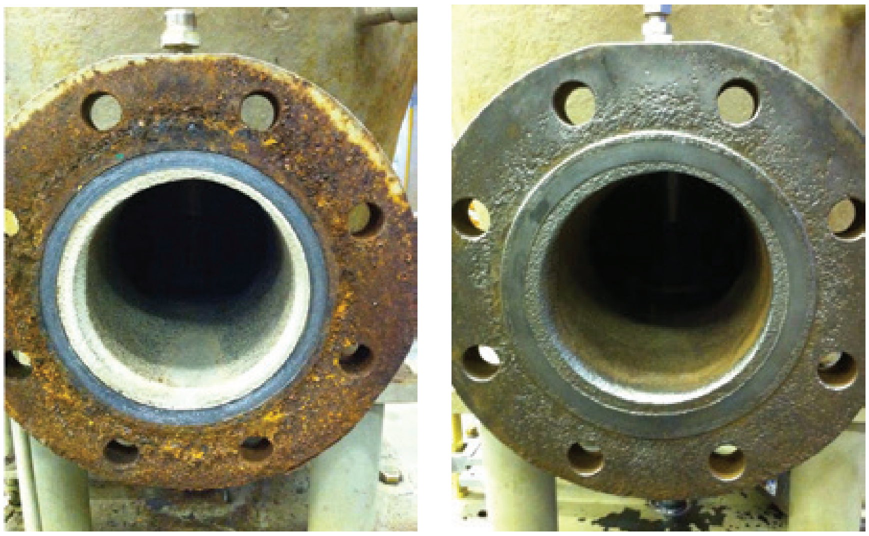
Instrument and wiring failures were associated with hot-gas leakage from flanges and casing penetrations that caused high compartment temperatures. There was a report of a turbine shell dropping relative to the exhaust frame because of age and other factors. The result: Rotor position was no longer concentric with stator casings.

Possible near-term repairs suggested:

- Manually dress casings during overhauls.
- Shim large gaps between flanges.
- Weld seal strips across flange joints.
- Install inserts were required.

Casing-alignment checks during major inspections was recommended with the suggestion to relocate bearings 2 and 3 to achieve a "compromise" in rotor position. Long-term repairs discussed included removing casings from the base plate, separating the turbine from the exhaust frame, machining flange faces and bolt holes, realigning the unit, and reassembling with larger dowels. Also noted: Be prepared to replace the exhaust frame and diffuser casings.

Check for corrosion of gas control valves on dual-fuel units, Young & Franklin's Norm Gagnon told roundtable attendees during a short presentation. Users having Frame 7B-EA gas turbines with dual-fuel capability should consider inspecting the outlet chambers of combined gas control valves for corrosion at their next opportunity. Corrosion can be severe



13, 14. Gas control valves can suffer severe corrosion (left) as evidenced by 35-mil loss of metal in some areas (right)

in some cases (Fig 13). On one unit, 35 mils was removed from the face of the valve's outlet flange (Fig 14).

The primary purpose of the valve assembly is to regulate the flow of natural gas to the gas turbine's fuel nozzles. Gagnon said that Y&F's research suggests hydrocarbons and sulfur entrained in the gas, and purge air, contribute to the issue. Recall that purge air is used to clear fuel nozzles when switching from oil to gas and vice versa and that backflow to the Y&F valve can occur during the purge.

Corrosion has been found on units throughout the US and Canada with problem valves being identified with the use of unheated gas. As a first step, Gagnon recommended that owner/operators assure 50 deg F of superheat in the gas at the valve inlet to be sure there are no entrained hydrocarbons. He also suggested that users review the fuel specifications in GE document 41040F concerning preheat, allowable hydrocarbons, etc.

Regarding inspection of your valves for corrosion, there is a plugged port in the valve discharge nozzle that allows borescope access to the outlet chamber. CAUTION: Before performing this inspection be sure you are in compliance with NFPA 56 regarding proper procedures for working on gas lines.

Combined cycle

Safety has been the No. 1 discussion topic at most user group meetings for the last couple of years. The open forum at CTOTF's Combined Cycle Roundtable, chaired by Erik Knutson, an assistant plant manager for Colorado Energy Management LLC, and the latest addition to the user organization's leadership committee, is a case in point as the bullet points below attest. Rick Shackelford, plant manager, Green Country Energy LLC, is the vice chair for this roundtable.

- Attendees revisited procedures for steam-drum door inspection and tightening after a recent industry fatality. Users were urged to develop procedures for torqueing drum doors and for steps to take when a leak is found. Participants generally agreed that attention to detail regarding alignment of the drum gasket is critical to preventing leaks. An attendee volunteered that frequent drum-door gasket leaks prompted his management to order a redesigned drum door from the OEM. Others tormented by the issue were urged to do the same.
- Remote racking devices to avoid arc-flash hazards were acknowledged as one of the most important safety devices in a plant. Not a major expense, users agreed, but a major safety improvement.
- Achieving proficiency in high-angle personnel rescue was a goal of several attendees. It was noted that local fire departments are not often well-trained for this. Suggestion: Use safety harnesses with stirrups to reduce load on legs if someone is hanging. Another: Use a safety harness and winch to lower personnel into locations difficult to access, thereby eliminating the need for rescue.
- Boiler-drum confined-space safety. What if someone loses consciousness during a drum inspection or repair? Does this confined space require a harness? Consensus view: Not at all plants; but there was agreement that a confined-space retrieval plan was necessary.
- Confined-space rescue involves considerable effort and expense for training, certification, and equipment (initial cost and upkeep). Can't expect much help from budget-constrained fire departments the group agreed. Possible solution: Plant provides seed money to the FD for confined-space rescue activities.
- Two plants partnered to donate a safety rescue trailer and equipment to a local fire department after the FD agreed to pursue training for plant-specific emergencies. Unintended consequence: New fire chief was not interested in keeping the arrangement when he took office. City manager rescued the plan by siding with the plants.
- Downside of working with your local fire department regarding surveillance of confined-space activities: If an emergency call comes in they won't show up onsite. This can result in unexpected delays during outages.

Nozzle cracking. Owner/operators attending CTOTF's Combined Cycle Roundtable were told by Scott Wambeke, PE, that HRST Inc's engineers are finding many more incidents of steam-drum nozzle cracking today than only a few years ago and advised users to inspect all drum penetrations as soon as is practicable. He called drum nozzle cracking a common problem and said it is found most often in downcomer nozzles.

Wambeke reminded attendees that thermal stress, the primary cause of the cracking, is related to steam-drum temperature ramp rate and that drum and nozzle thicknesses determine the allowable ramp rate. The type of nozzle weld is another important factor. Full-penetration welds are much more resistant to cracking than partial-penetration welds, he said, showing a few sketches of the types of drum welds typically used. Weld details also come into play, Wambeke continued, asking users not to forget that sharp inside corners concentrate stress.

Non-destructive examination (NDE) was next. Visual inspection is useful, the HRSG expert said, but not sufficient on its own. Surface NDE is better—that is, dye-penetrant and magnetic-particle inspection methods. Volumetric NDE—shear-wave ultrasonic (UT), phased-array UT, and radiography—is better still for the additional information it provides. Wambeke stressed that if you have been relying on visual inspection only, cracks may very well exist.

Where to look. For pass-through downcomer nozzles and other nozzle welds easily seen from the drum, he suggested that users begin their condition assessment with a visual inspection inside the drum. If there are no visible indications, follow up with mag-particle or dye-penetrant testing. If crack indications are found, nozzle welds also should be inspected from the drum exterior. Riser and steam-outlet nozzles also should be inspected while inside the drum, particularly if cracking of downcomer nozzles is identified. Sometimes access can prove difficult and you may have to remove part or all of the belly pan, or the final steam separator.

For drums with set-on downcomer nozzles with their welds on the outside of the drum, conduct visual and NDE inspections from the drum exterior. Opt for volumetric NDE when it's necessary to determine crack depth.

Regulatory, compliance

One of the most valuable aspects of CTOTF's Regulatory and Compliance Roundtable, chaired by Scott Takinen of APS (Alan Bull of NAES is vice chair), is keeping plant management up-to-date on changes to existing regulations and where their attention should be focused. A presentation by Matthew Stryker, manager of CIP compliance monitoring at SERC Reliability Corp, outlined the coming changes and potential impacts to NERC CIP standards.

Stryker told the group that CIP Version 4 is up for FERC approval and, if passed, can lead to some significant modifications to previous versions of CIP-002, in particular. Changes would go into effect about two years after approval. First and foremost, multiple "bright line" criteria, adopted to eliminate subjectivity by entities, would now be used to identify critical assets (CA) and critical cyber assets (CCA) instead of the risk-based self-reporting methodology previously acceptable.

For generation owners, the following are considered CAs:

- A generating plant with a real power capability of 1500 MW or more.
- Reactive power resources with a nameplate rating of 1000 MVAr or more.
- Generating facilities deemed by the transmission planner as necessary to avoid adverse reliability impacts on the bulk electric system (BES).
- Black-start resources.
- Special protection systems, remedial action scheme, or automated switching systems that operate BES elements.
- Facilities that perform automatic load shedding of 300 MW or more.
- Control centers that perform the functional obligations of the reliability coordinator.

A new addition regarding CCA identification for generating plants with a real-power capability of 1500 MW or more states the only cyber assets that must be considered are those shared cyber assets that could, within 15 minutes, adversely impact the reliable operation of any combination of units that, in aggregate, equal or exceed 1500 MW.

Welcome to the club. Results from a recent NERC data request to gauge the number of plants that would be drawn in by Version 4 identify 234 generating units with CCAs having black-start capability and 475 generating units with CCAs because of factors other than black start. This represents a marked increase from the current number of generation CIP assets.

I have identified CCAs. What next? Stryker stressed that a good first step is to consider the cyber assets you have which will require technical feasibility exceptions (TFEs) available for specific standards where achieving strict compliance is not possible (physical security, remote access, anti-malware, password protection, etc). TFEs can take some extra time to put together because it is very important to coordinate with a vendor or developer. About half of all TFEs are submitted directly by vendors on behalf of the plant. Also required is a strategy for terminating the TFE and returning to strict compliance or evidence of why compliance is not attainable.

Next, consult the new NERC CIP implementation plan to understand the timelines associated with standards CIP-003 to CIP-009. Timelines vary from six to 24 months depending on your situation, and during that time, considerations for budgetary concerns, personnel additions/training, and planned outages should be prioritized.

Stryker finished up by providing the following list of resources that will bring you up-to-speed and assist your organization with developing an effective implementation plan:

- New CIP implementation tables.
- Background on CIP implementation and the old implementation tables.
- Identifying critical assets.
- Identifying critical cyber assets.
- Sufficiency review report.
- CIP-002 public NOPs.
- NERC's case notes for possible violations.
- CIP Version 5 project page.
- TFE procedure.
- NERC Compliance Application Notices.
- CAN-0017 regarding password TFEs.

Pratt & Whitney

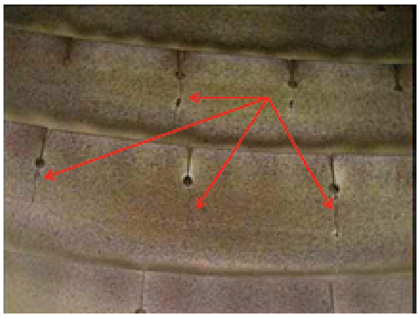
A summary of recent borescope-inspection findings by Mike Hoogsteden, field service manager, Advanced Turbine Support LLC (ATS), Gainesville, Fla, pinpointed areas of the FT8 of greatest concern to owner/operators of the expanding fleet. The presentation on the popular aero engine, manufactured by Pratt & Whitney, was made during a special session for FT8 users.

Hoogsteden walked attendees through the engine from the compressor bellmouth through the power turbine (PT). Rubs, tip discoloration, and minor deposits and impact damage characterized typical findings in the low-pressure (LP) compressor. Biggest surprise: compressor case damage. This had not been seen by ATS inspectors until recently and has been identified in four engines thus far (Fig 15).

The service manager's photos of tip rubs and dings in the high-pressure (HP) compressor didn't reveal anything every user in the room hadn't seen previously. An inoperable engine-heater check valve seemed to generate the most interest. Hoogsteden said ATS finds inoperable check valves on 20% of all engines inspected. These valves are critical for keeping engines above dewpoint temperature when they are not in operation.

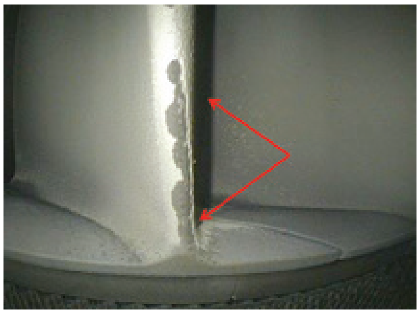
Wear and tear identified with the combustion section included relatively minor liner coating loss and cracking (Fig 16), plus a damaged J-seal on one engine. In the HP turbine, coating loss in spots is relatively common on the

15. Damage to the compressor case was surprising

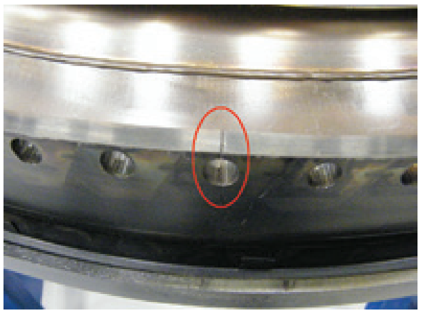


16. Wear and tear of combustion liners is relativelycommon

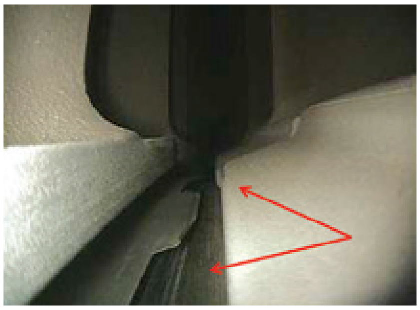
17. Erosion at the base of vane segments is found occasionally



18. Leading-edge coating loss from LP turbine S1 vanes is of little concern



19. Cracking of the power turbine's R1 nozzle retainer ring is conducive to air seal damage



20. Air seal damage shown is significant and relatively easy to miss in a borescope inspection because the material below it resembles an air seal

21. Inspectors check for platform wear on the trailing edges of S1 vanes.

22. Rotor-blade tip shroud rub sometimes is identified in R3 and R4 of the power turbine

suction side of rotating blades. Erosion at the base of vane segments is found occasionally (Fig 17). Interestingly, erosion occurs gradually and little collateral damage has been experienced in engines inspected by ATS. Erosion can approach the air cooling holes in some instances.

Small areas of coating loss also can be found on the leading edges of LP turbine S1 vanes (Fig 18) and blades. Measurements taken by inspectors in the exhaust-case area can help ATS determine if the gas generator has moved and, if so, by how much. Thinking is that shifting of the GG case could be a factor contributing to R1 air seal damage found in some power turbines (PT).

Additionally, is believed that a crack in the PT's R1 nozzle retainer ring (Fig 19) may be conducive to a condition known as "lean back," which also can contribute to R1 air seal damage (Fig 20). Next, trailing edges of S1 vanes are checked for platform wear (Fig 21) and R2 seals are inspected to be sure they're in good condition. PT rows 3 and 4 are checked for rotor-blade tip shroud rub (Fig 22).

Siemens legacy units

Mike Rutledge earned a 10 in his debut as chair of the CTOTF Siemens Roundtables for conducting, with Vice Chair Rocky Roos, an engaging panel discussion to identify options for making legacy units—primarily simple-cycle engines—more competitive. Rutledge, manager of plant technical support for SRP, moved to his current CTOTF assignment after serving as chairman of the Combined Cycle Roundtable for several years. Roos is maintenance superintendent for Municipal Light & Power in Anchorage, Alaska.

Panelists included the following respected metallurgists and engineers:

- Richard Curtis, VP engineering, Eta Technologies LLC.
- El Williams, Sulzer Turbo Services.
- Greg Snyder, engineering manager, Dresser-Rand Turbine Technology Services.
- Sal DellaVilla, president, Strategic Power Systems Inc.
- Doug Nagy, manager of components repair, Liburdi Turbine Services Inc.
- Scott Wambeke, HRST Inc.

Rutledge lit the fuse and the interactive discussion between panelists and owner/operators in the audience burned for the two full hours allotted. Virtually everyone in the room agreed that the key factor influencing business potential is geography (location/location/location). For example, in the Northeast many units have capacity payments and in this market the most important factor is starting reliability. The grid imposes penalties if you can't start units as required, and unless you can prove that you actually can meet grid requirements after a failure to meet expectations, a plant can lose its contract.

In areas where plants are competing for dispatch, the cost of generation is important and this typically gives F- and G-class plants the edge because of their generally low heat rates. Output and time to deliver full load are important parameter that can influence the bottom line in some regions as well.

As always, Curtis said, and in particular with legacy engines, you never get something for nothing. The group agreed that the least important attribute was heat rate; even under the best circumstances, legacy machines can't compete effectively with current models on an efficiency basis. Starting time can be quite important and that was discussed in length. Mention was made of the early W501 models, which are limited in how fast they can start because their interference-fitted compressor wheels migrate when heated too quickly. Relative to start time, purge cycles, controls limitations, and compromises in clearances also were debated.

Maximizing output was another point pondered, with over-firing and mass-flow increase (water or steam injection, inlet fogging, wet compression, etc) offered as alternatives. Cost-side improvements discussed included extension of outage intervals and component lives.

One user raised the question of the true cost of startup. Legacy units can have an advantage here in terms of lower outage/maintenance/parts costs compared to F-class units, despite the higher outputs and lower heat rates of the latter. CCJ

Fall user-group meeting lineup

September 16-20

Value proposition

The fall user-group meeting calendar opens with CTOTF's Fall Turbine Forum and Trade Show at San Diego's Rancho Bernardo Inn Golf Resort & Spa, September 16-20. The Combustion Turbine Operations Technical Forum, which has been serving gas-turbine owner/operators longer than any other user group, offers a plant-wide technical perspective in its conference agenda, while incorporating non-technical subjects—such as regulatory and compliance programs—which have direct impact on successful plant operations.

Chairman Bob Kirn of TVA says a goal of the organization is to serve as an extension of individual-company technical services departments. "Our active presentation library offers an immediate source of information, industry contacts, and problem solutions," he notes. "CTOTF's renowned conference roundtables have been enhanced with technical training delivered by industry experts through the group's CT-Tech program, shop tours, service-provider presentations, and a robust vendor fair," Kirn continues.

CTOTF meetings are content-rich and the information flow is relentless. To illustrate: The Fall Turbine Forum will have 15 roundtables totaling 74 hours of presentations and discussion, 10 meals and social functions for informal sharing of information, and a trade show. If you want to know more about the subject-matter experts who develop and conduct the various roundtables, access the org chart at www.ctotf.org and click on the person's name for an abbreviated resume.

The following list of roundtables scheduled for San Diego illustrates the breath of coverage of a CTOTF meeting, including presentations and discussion of engines made by all the major OEMs:

- Industry issues.
- O&M and business practices.
- GE F-class machines.
- Alstom gas turbines.
- Solar engines (includes a shop tour).
- Pratt & Whitney FT4s and FT8s.
- GE E-class and legacy machines.
- Combined cycle.
- Siemens V and H gas turbines.
- Regulatory and compliance.
- GE Aero engines.
- Mitsubishi machines.
- Siemens legacy gas turbines.
- Generators, high-voltage electrical, and I&C.
- Siemens F- and G-class engines.

Details for each of the roundtables are directly accessible via the program overview at http://www.combustion-turbine-operations-technical-forum.org/ConferenceFall/UsersWeekOverview. html.

Top sponsors for the CTOTF conferences in 2012, called Super Champions, are the following: Allied Power Group, Combustion Parts Inc, Dresser-Rand Turbine Technology Services, EagleBurgmann EJS, Hy-Pro Filtration, NAES Corp, PSM, Sulzer Turbo Services, Universal Plant Services, Young & Franklin Inc.

September 24-26

ACC Users Group to meet in Gillette

The Air-Cooled Condenser (ACC) Users Group, chaired by Andy Howell, a senior systems chemist for Xcel Energy, opens its 2012 meeting in Gillette, Wyo, September 24, with a welcome reception at the Chophouse Restaurant from 5 to 6:30 p.m. Other members of the steering committee who will be on hand are Dave Rettke, NV Energy; Hoc Phung, PG&E; and Barry Dooley, Structural Integrity Associates Inc.

The program for the organization's fourth annual conference, September 25-26, at the Cam-Plex includes prepared presentations, open discussion sessions, and tours of ACCs at two plants in the area. Details are available at www.acc-usersgroup.org.

Gillette is the global center of excellence for ACC operation and maintenance. It's probably safe to say that if the engineers and technicians at the seven dry-cooled plants within 10 miles of Gillette—Simpson 1, 2; Wyodak; Wygen 1, 2, 3; and Dry Fork—haven't experienced a particular ACC issue, no one has. These people will be at the meeting to share their experiences.

Dry cooling got its start in Gillette and the technology has matured there. Consider the following:

- Simpson 1 is equipped with the first ACC installed in North America.
- Wyodak, which had the largest ACC in the world for more than two decades, was the first plant to completely replace the heat-transfer modules on its ACC.
- Dry Fork is the most recent ACC-equipped powerplant to begin service in North America.

If you are considering participation, bear in mind that the Gillette airport has a limited number of flights and when those are filled the only practical options for most attendees would be flying to Rapid City or Casper—both a two-hour drive from Gillette. You may want to make travel arrangements before registering. Chairman Howell assures there will be a seat available (and food) for everyone who can get to Gillette.

Host generating companies are Basin Electric Power Co-op, Black Hills Power Inc, Black Hills Electric Generation Inc, Cheyenne Light Fuel & Power, Montana-Dakota Utilities Co, PacifiCorp Energy, and Wyoming Municipal Power Agency.

Sponsors for this year's meeting are Baldor Electric Co, Conco Systems Inc, Evapco-BLCT Inc, GEA Power Cooling, Howden, Johnson Controls Inc, and SPX Cooling Technologies.

October 16-18

No-frills CCUG focuses on formal presentations, open discussion

The Combined Cycle Users Group (CCUG), chaired by Larry Small of Calpine Corp, opens its 2012 Annual Conference at the Buena Vista Palace Hotel & Spa in Lake Buena Vista, Fla, (adjacent to Disney World) October 16 with a welcome reception from 5 to 6:30 p.m. The formal meeting will be held October 17 and 18. A preliminary program is posted on the organization's website at www.ccusers.org.

The CCUG's meetings are dedicated to formal presentations and attendee-driven discussion sessions focusing on the design, construction, operation, and maintenance of the integrated plant. Additional topics addressed include NERC and other regulatory impacts on plant operation, environmental rulemakings, plant mods to achieve performance goals, safety initiatives, professional development, skills training, etc.

Prepared presentations and discussion this year focus on the following:

- Reliability and strategic planning—including cycle design improvements to improve performance, reduction of costs and emissions, emerging technologies, challenges associated with integrating renewables.
- High-energy fluid systems/equipment—including valve and piping issues, boiler-feed pumps.
- Issues on the minds of attendees.
- Challenges of modern control and electrical systems—including cyber security, remote monitoring, instrumentation, alarm management, DCS, startup and shutdown automation.
- Performance monitoring and assessment of gas and steam turbines and heat-recovery steam generators.
- Operating challenges and changing paradigms of combined-cycle plants.
- Water management, chemistry, and corrosion control for the steam/water cycle and cooling and makeup water.

- Safety management—including OSHA VPP, fire protection, arc flash, job hazard analysis, manual of change, work permits, culture, process safety management.
- Best practices, lessons learned, and knowledge sharing.

Thought leaders include Chairman Small, Vice Chairman Robert Mayfield of Tenaska Inc, TVA's Mike Hoy and Daniel Noles, Steve Royall of PG&E, Andy Donaldson and Dan Sampson of WorleyParsons, Phyllis Gassert of Dynegy Midwest Generation Inc, Performance Specialist James Koch, and Calpine Corp's Tony Wiseman.

Sponsors for this year's meeting are AAF International, A&R Turbines, Emerson Process Management, MRG Inc, Toshiba Power Systems Co, and URS Corp.

Yet another use for dry ice: Painting prep

Donaldson Company Inc's Barry Link, a familiar face at user group meetings, told the editors that his company and Precision Iceblast Corp (PIC) had teamed up to offer upgrade and rehabilitation services for gas-turbine air inlet systems. Deterioration of metal surfaces is relatively common in air inlet houses because painted carbon steel is the material of choice for filter and evap-cooler structural members among parsimonious owners, and the environment typically is high-moisture. Rusting metal contributes to wear and tear of compressor airfoils because oxide continually flakes off and flies downstream at high velocity into the unit.

Theoretically, just about any maintenance person can wire-brush away rust spots and hit them with paint. But that won't cut it in the air inlet house. Rusting is virtually sure to continue under the glob of paint and the next flake that comes off will be bigger, heavier, and do more compressor damage.

Donaldson always offered customers painting services where required, typically using sandblasting equipment to prep surfaces after removing filters and evap-media fill. Cleanup always was a painful part of the job, recalled Link. Every bit of grit and all the paint it removed had to be swept/vacuumed up and removed prior to painting. No one wanted that material being swept downstream into the compressor.

PIC had an idea: It could remove rust, lose paint, etc, with high-pressure CO_2 blasting, leaving only rust and paint chips for the clean-up crew. Plus, the company had crews trained in powerplant practices from its work cleaning HRSG heat-transfer surfaces, as well as the scaffolding to access all surfaces requiring treatment. Finally, PIC had coatings experience from work in other industries.

Here's the way a typical evap-cooler restoration project works for an F-class installation: Donaldson crew removes the evap media on the first day; PIC does the scaffold erection, installation of curtains downstream of the cooler, CO_2 blast, coating (12 mils of an epoxy designed for marine environments), curtain removal/scaffold breakdown, and cleanup over the next four days; Donaldson crew reinstalls media (previous or new) in two days.

The editors called a couple of customers. One plant manager with four 7EAs and one 7FA—all peakers—said he had a real corrosion problem with his big machine and hired Donaldson to correct it. Coating lasted less than a year. Surface preparation by sandblasting was inadequate he said. Next attempt was by a Donaldson/PIC team. "Seems to have worked well," the PM added, "More than a year later, the evap cooler still looks OK." Evap coolers on two of the 7EAs were overhauled the same way last fall; success. Coolers on the remaining two units will be restored this fall.

The second user contacted said he hired Donaldson to replace filters (plant gets about five years on a set of filters) and evap media (nominal 10-yr life) and to restore the evap-cooler framework. He knew PIC from previous HRSG work and embraced the partnership for his project. Final assessment: The two teams worked seamlessly, quickly, and efficiently.

A back-of-the-envelope calculation suggested that the plant could repaint the evap cooler as often as every two years and still be less expensive than retrofit with a stainless-steel frame. Cooler condition is checked annually.

Also, this user took the opportunity to make a small modification to the evap cooler as suggested by Donaldson: Installation of drains at the ends of the water distribution header to eliminate packing of debris and promote better distribution of water across the media. Better performance resulted.

October 23-25

Shop tour adds value to meeting

The 7EA Users Group, chaired by Pat Myers, plant manager of AEP's Ceredo Generating Station, announces that the first day of the organization's annual conference, October 23-25, in Greenville, SC, will be devoted to presentations by the OEM and a tour of GE's manufacturing facilities. The meeting will be held at the Embassy Suites Greenville Golf Resort and Conference Center.

A vendor fair is scheduled for Wednesday evening, October 24. No other details were available through the user group's website at the CCJ's deadline.

Members of the steering committee in addition to Myers are Michael Johnson of Turlock Irrigation District, Guy LeBlanc of First Energy Corp, Ray Lathrop of Corn Belt Power Co-op, Jim Beveridge of Utah Associated Municipal Power Systems, Amy Alix of Progress Energy, and Lane Watson of FM Global.

Ovation Users' Group recognizes Calpine's Carville Energy Center

Presentation of the Ovation Users' Group's awards to power and water projects for their contributions in the development and implementation of controls solutions to improve performance, reduce O&M costs, and increase security and safety is a highlight of the organization's annual meetings.

At the awards luncheon Tuesday, July 28, only a few days before this issue went to press, Calpine Corp's Carville Energy Center was honored as the Power Project of the Year by the user group's executive board. The award presentation was made by Bob Yeager, president, Emerson Process Management Power & Water Solutions, to Calpine's Arthur L Mayclin, PE, manager of I&C engineering (corporate), Carville IC&E Tech Shane Lowe, plus Richard Johnson and Ralph Owens (Fig 1).

Lowe was involved with logic issues during the conversion, as well as

1. Calpine Corp's Rick Johnson, Ralph Owens, Arthur Mayclin, PE, and Shane Lowe (l to r) beam with pride as Bob Yeager, president, Emerson Process Management Power & Water Solutions, announces that Carville Energy Center was voted 2012 Power Project of the Year by the Ovation Users' Group

with system commissioning. He also compiled some of the documentation required in support of the bid. Mayclin worked with the plant engineer to produce the technical specifications. He also participated in the review of proposals and other project tasks.

Carville, a 450-MW 2 × 1 combined cycle powered by GE 7FA.03 gas turbines, began commercial operation in 2003. Alstom heat-recovery steam generators and an Alstom steam turbine complete the power block. Plant manager is Reg Jones.

While Carville's equipment lineup is a relatively standard configuration, the fine print revealed three different primary control systems: Mark VI for the GTs, Advant for the steamer, and Teleperm-XP (better known as TXP) for balance-of-plant. As the years passed, the O&M challenges associated with operating and maintaining three systems proved challenging.

Initially, the plant's goal was to

2. Ian Harris, PE, accepts the 2012 Water Project of the Year Award for the City of San Diego from Emerson's Bob Yeager

3. The Ovation Users' Group's Award of Excellence went to Indianapolis Power & Light Co's Petersburg Generating Station. Sean McDonald (left) and Charlie Smith accepted the award

replace the Advant system. Reasons included the relatively high cost of parts and service, difficulties encountered in obtaining critical parts, and limited onsite staff for troubleshooting upsets and/or implementing control and graphics modifications.

After the award was issued to replace the Advant system, the decision to retain the TXP system was revisited because of cost and parts/service availability concerns. An Ovation migration emerged as a logical and economical decision. Important to note is that by using an Ovation-to-ET200M I/O interface, the plant realized considerable cost saving because the TXP I/O modules did not have to be replaced.

In sum, by converting the Advant and TXP systems to one DCS, Carville Energy Center benefits by having one common platform, a reduction in spare-parts inventory and personnel training, and a smaller network and workstation footprint.

City of San Diego's Metropolitan Biosolids Center received the user group's Water Industry Project of the Year Award for its Ovation migration without a plant shutdown. The live migration of 41 WDPF (Westinghouse Distributed Processing Family) controllers and 23 Solaris workstations to an Ovation system running Windows XP, while combining the facility's three data highways into one, was accomplished without any overtime.

The City's Ian Harris, PE, who accepted the award from Yeager (Fig 2), told the group that Emerson mitigated the risk of accidentally knocking the huge plant offline while cutting over from WDPF to Ovation by installing the new system in parallel with the old. Harris explained how this was done using the plant's three digesters as an example. The first digester to be migrated to Ovation was put in manual while the other two continued to operate in auto on the WDPF system. When the first migration was complete, the second digester was put in manual and migrated, and so on.

The order of the cutover plan was modeled during the factory acceptance test to be sure the migration sequence was correct before any field work was done. Also, to streamline the migration, the converted graphics were reviewed by Harris and City staff online.

The overall Award of Excellence went to Indianapolis Power & Light Co's controls replacement project at its coal-fired Petersburg Units 1 and 4 (Fig 3). The boiler controls, burner management system, data acquisition system, turbine controls, etc, for these generating units all were at the end of their useful lives: They had limitied functionality and obsolescence issues, and parts and services were hard to obtain.

Today, both units have better response times for dispatched load changes, as well as rundowns and runbacks in the event of a process upset, plus:

- Expanded alarming and notification capabilities.
- The ability to make process changes

and/or track operating parameters to comply with new environmental and NERC/FERC regulations.
- A Global Performance Advisor to provide plant personnel the information needed to operate at top efficiency.
- A significantly improved turbine operations protection scheme.

Precision Iceblast on network TV

Keith Boye, VP of Wisconsin-based Precision Iceblast Corp called **CCJ's** editorial offices to report that PIC was featured on the World's Greatest TV show in late July (Fig 4). Eight companies are profiled in each half-hour segment of the weekly show, which has been running for six years.

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World's Greatest Production Manager Josh Kessler told the editors that PIC was selected for the interesting work it does and for its "stellar reputation" among customers in the industries served. He said development teams consisting of producers, writers, and researchers continually scour the nation's myriad industries for interesting products, services, etc. Suppliers selected for further review are investigated and evaluated. The leading candidates then are interviewed and a company is selected for inclusion in the show. A script is prepared and film crew typically spends a day in the field shooting the company segment. The profile demonstrating how HRSG tube bundles are cleaned was filmed at an F-class 2 × 1 combined cycle in March 2012 (Fig 5).

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Association news

TICA, the Turbine Inlet Cooling Assn, Naperville, Ill, announces the availability of a complimentary online forum for gas-turbine users, webinars on turbine inlet cooling (TIC) technologies, a database of TIC installations, and bibliography of technical papers. Owner/operators must register for TICA membership (no charge through end of September) to participate in the forum. Go to www.turbineinletcooling.org.

TICA's first webinar in its complimentary series, "An Overview of Turbine Inlet Cooling," presented in late June, was a success, Don Punwani, the association's executive director, told the editors. Next webinar, "Wetted-Media Evaporative Cooling Technology," will be conducted August 22. Register for this and future webinars on the website. Refer questions to Punwani at exedir@turbineinletcooling.org or call 630-357-3960.

Powerplant news

Dean Motl, plant manager, New Harquahala Generating Co LLC, announces the eighth annual Joe Lopez Memorial Golf Tournament, September 24, at the Raven at Verrado Golf Club in Buckeye, Ariz. Last year the plant raised more than $20,000 for the Muscular Dystrophy Assn; the 2012 goal is $25,000.

Competition is an 18-hole, four-person scramble. Greens fees, range balls, cart, and lunch are all provided by New Harquahala. Donations are not required to participate. RSVP by September 4. Registration is at 6:45 am, on September 24, shotgun start at 7:30, lunch and awards at 12:30. The game-within-the-game includes a hole-in-one contest, beat-the-pro hole, and putt-for-dough contest. Refer questions to Motl at dmtol@harqgen.com, 623-810-1346.

Contracts

MPS Canada Inc, a wholly owned subsidiary of Mitsubishi Power Systems Americas Inc, receives an order for two M501GAC gas turbine/generators from the TransAlta Generation Partnership for the Sundance 7 power generation facility in Alberta. Mitsubishi has received orders for more than 75 M501G engines worldwide, half that number for service in North America.

Siemens AG reports POSCO Energy of Korea has ordered three single-shaft H-class combined cycles for service in summer 2014. Each unit is rated over 420 MW at 61% gross efficiency and designed for 250 annual starts. Full power can be achieved in 30 minutes on a hot start.

Puretec Industrial Water, Oxnard, Calif, renews contracts for ultrapure water with Arizona Public Service Co and Salt River Project for another five years.

Company news

NAES Corp, Issaquah, Wash, adds a combustion turbine services group with over two centuries of experience to its Houston-based Turbine Services Div. The new group is led by Darron Pruitt, who joins NAES as director of turbine field services. Other key appointments: Jimmy Cassel, operations manager; Technical Advisors Glenn Hogan and Roger Howell; Andy Hill, field engineer; Field Services Supervisors Paul McCraw, Jeff Townley, Todd Nessmith, and Billy James; and Ryan Pruitt, project control engineer.

"The addition of this team solidifies our position as the premier third-party turbine services provider," says Butch Kimbrell, VP/GM of the company's Turbine Services Div. "We are well equipped to address customer needs in the growing combustion-turbine market with the right mix of tools, technical knowledge, supervisory skills, and labor.

Advanced Filtration Concepts Inc, Los Angeles, re-launches its website at www.advfiltration.com, making it more user-friendly and far more comprehensive in its offerings. It offers details on air filtration options, service capabilities, installation, delivery, etc.

Membrana-Charlotte, a division of Celgard LLC, expands its Liqui-Cel® membrane contactor store at the request of customers wanting to purchase a greater variety of degassing products online. Shop now at http://store.liqui-cel.com.

GP Strategies Corp is the new name for General Physics Corp. GP Strategies previously was simply the name of General Physics' publicly traded parent company. Only the company name changes: The Energy Services Group remains a full-service provider of workforce development and performance engineering solutions.

Analysts Inc, Hawthorne, Calif, moves its Southeast operations to Suwanee, Ga, and expands its lab there to nearly 16,000 ft^2. The company provides oil, coolant, and fuel analysis services to the power generation and energy-intensive process industries.

Dresser-Rand Co acquires certain intellectual property assets, including patents and trademarks, from Energy Storage & Power LLC and Dr Michael Nakhamkin. The company is now able to provide the smallest to the largest compressed-air energy storage projects to meet specific grid-scale requirements.

Products/services

ESCO Tool, Holliston, Mass, offers a full line of cutter blades and locking cutter heads for its welding end-prep tools that can bevel, face, and bore simultaneously, while improving weld surfaces (Fig 8). Millhog® cutter blades, available for any angle of prep from 37.5 to 10 deg, are able to produce a thick chip without cutting oils. They are suited for stainless steels, P91, and other hard tube and pipe materials from 0.5 to 36 in. OD.

Portable welding end-prep tool features a variable-speed 14-amp motor for applications where compressed air is not available (Fig 9). Wart Millhog is an ID clamping tool suitable for machining highly alloyed stainless steel pipe and tube from 0.75 in. ID to 4.5 in. OD without cutting oils.

Millhog Dictator, an ID-clamping welding end-prep tool features extra-wide clamps for rigidly mounting inside pipes from 4.5 in. ID to 18 in. OD (Fig 10). Powered by a pneumatic motor, tool develops 4000 ft-lb of torque. A hydraulic motor is an option. Tool eliminates the need for hand grinding and the use of complex clamshell tools.


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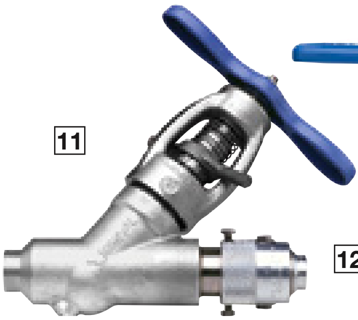

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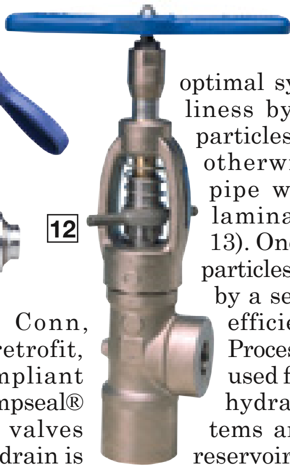

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Conval Inc, Somers, Conn, announces an easy-to-retrofit, single-weld, OSHA-compliant safe vent drain for its Clampseal® Y-pattern forged globe valves (Fig 11). SaVD safe vent drain is available in 0.5 to 2 in. sizes, through ASME 2500 pressure class with NPT, butt- or socket-weld ends. Standard materials include a range of stainless steels and F22.

Clampseal forged throttling valves for severe-service applications assure repeatable flow control and dependable shut-off (Fig 12). Valves are available in sizes from 0.5 to 4 in. and in pressure ratings from ASME Class 900 to Class 4095. Materials include Type-316 stainless steel, F91, F92, and SA 182 F22. Catalog with engineering data can be accessed at www.conval.com.

Oil Filtration Systems, Boerne, Tex, announces the availability of oil reclamation, purification, and oil flushing field services. Periodic high-velocity hot-oil flushing can help assure optimal system cleanliness by dislodging particles that would otherwise cling to pipe walls during laminar flow (Fig 13). Once dislodged, particles are removed by a series of high-efficiency filters. Process also can be used for cleanup of hydraulic oil systems and diesel oil reservoirs.

The company also has developed a line of filters and coalescers to remove particulates and water from diesel oil and other gas-turbine fuels (Fig 14). The two-step fuel-cleanup process works this way: First, high-efficiency particulate filters remove particulates down to 1 micron; next, high-efficiency coalescers and separator elements remove free water to less than 50 ppm.

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