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7F USERS GROUP

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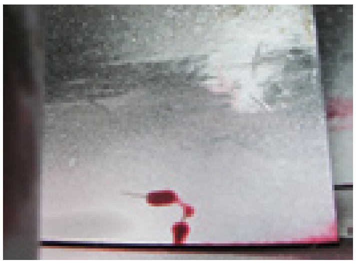

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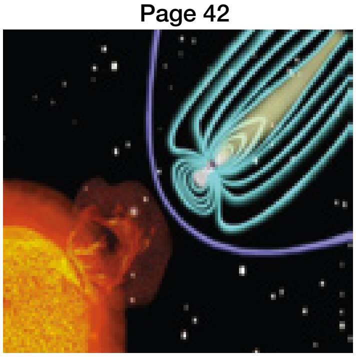

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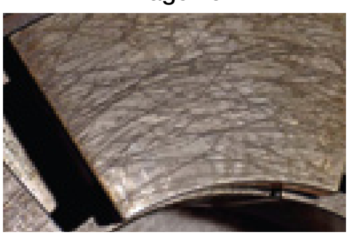

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INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

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Only days away are the two of the year's first user group meetings serving owner/operators of gas turbines. The 501F and 501G Users Groups will be holding separate technical conferences at Saddlebrook Resort (Tampa) February 12-16, but will come together for discussions on issues of mutual interest, vendor fair, meals, and social events. Get details at http://users-group.org.

501F Chairman Russ Snyder told the editors that Monday's (February 13) feature events are the vendor fair and 50 half-hour presentations (including Q&A) by the leading vendors. Tuesday is Siemens Day with thorough coverage by the OEM's engineers of engine issues from air inlet though the generator, plus updates on product enhancements to improve reliability/availability and efficiency and reduce emissions and operating costs.

Wednesday begins with an open discussion on fleet safety concerns and solutions. More than half a dozen user presentations are sandwiched among roundtable discussions on the inlet and exhaust section, hot section, combustor section, and compressor.

Thursday morning features these breakout tracks: Siemens mods and upgrades; Siemens T3000 session followed by a user-only T3000 experiences discussion; TXP users-only session followed by a Siemens TXP session. Thursday afternoon is dedicated to steam turbines.

The Western Turbine Users Inc kicks off its 22nd Annual Conference and Exhibition Sunday March 18. It will bring together nearly 1000 owner/operators, vendors, and consultants in the Pasadena Conference Center for the opening of the vendor fair at 5:30 (visit www.wtui.com).

The conference, dedicated to aeroderivative gas turbines for land and marine service manufactured by GE Energy, begins Monday morning with a general session. Attendees will hear from the OEM and the five depots it has licensed to perform engine overhauls: TransCanada Turbines, MTU Maintenance, Air New Zealand, Avio, and IHI.

Introductions complete, the owner/operators will participate in the first of five breakout sessions for the LM2500, LM5000, LM6000, and LMS100, which are conducted in parallel. These sessions are the focal point of the event. Nearly 10 hours of in-depth discussion and presentations by top aero experts are dedicated to each of the four engines. Bring your questions; you'll get qualified answers.

CTOTF's Spring Turbine Forum is the meeting of choice for gas-turbine owner/operators who need information on more than just one engine model, so it's ideal for generation executives, asset managers, and plant directors. Access the agenda at www.ctotf.org. Digging into the program it's easy to understand why CTOTF Chair Bob Kirn of TVA says the Spring Turbine Forum is in lock step with the group's "The Total Plant Concept." The meeting does not just address gas turbines. Note the sessions dedicated to industry issues, O&M and business practices, generators, controls, electrical systems, etc.

A highlight of the conference is the presentation of the CCJ's 2012 Best Practices Awards. Finally, the Spring Turbine Forum offers a special opportunity to bring junior members of your power generation staff up speed on gas turbine technology. Note the two three-hour CT-Tech sessions on Tuesday and Wednesday evenings.

Unwavering commitment to the industry at 20 years and counting

The 7F Users Group hosted its 20th anniversary conference last May in Houston's Westin Galleria, attracting about 250 owner/operators to the world's largest gathering of F-class users and the equipment and services providers that serve them.

The organization has grown dramatically since its first meeting in Baltimore, Nov 19-20, 1991, attended by 14 O&M personnel from four companies. The only 7F engine in service at that time was Virginia Electric & Power Co's Chesterfield 7. It had been integrated with an existing steamer and new heat-recovery steam generator to configure a 1 × 1 combined cycle.

Fast forward to today: The OEM has shipped to customers more than 1000 F-class gas turbines since Chesterfield 7 left the shop. The large majority of these units are 7FAs.

The meticulous minutes of the first meeting focus on the gas turbine (7F history, p 34). Recent conferences have been multi-dimensional, with robust sessions on HRSGs, steam turbines, and electric generators, in addition to those on the engine's compressor, combustion system, turbine, auxiliaries, and controls.

Another big difference between the meetings of yesteryear and today: The minutes of the first meeting don't mention the OEM's participation. The Houston program, which began Monday, May 9, offered two days of OEM presentations, reflecting how F-class machines have grown in complexity over the years to satisfy ever more demanding environmental regulations and owners' goals of higher efficiency and availability/reliability.

The first meeting also did not have a vendor fair or vendor presentations. The 2011 conference had vendor fairs on three nights, one exclusive to the OEM's products and services. More than 100 companies participated in the exhibition the first two evenings.

The 2011 technical program included (1) informal user presentations, (2) open discussions, and (3) special presentations by representatives of 15 third-party vendors. The first two are summarized on the next several pages; vendor presentations are in the second half of this report, beginning on p 16. The steering committee—expert user volunteers all—developed the program and conducted the meeting (Sidebar 1). Sheila Vashi and her colleagues at Vision-Makers organized the event. There were 14 sponsors (Sidebar 2).

7F USERS GROUP

2012 Conference and Vendor Fair

May 14-18 • Westin La Cantena • San Antonio

Agenda highlights for user attendees:

Monday, May 14. Golf tournament (0800 shotgun start, additional fee for this optional event); HRSG Workshop presented by HRST Inc (0830-1200, additional fee for this optional event); optional tours of Pratt & Whitney shop facilities for the manufacture and repair of 7F hot parts, 0800-1100, 0930-1230, or 1100-1400; optional afternoon sessions, 1400-1730; keynote address and welcome reception, 1730-2100.

Tuesday, May 15. General session, 0800-1545; vendor presentations (first group), 1545-1630; vendor presentations (second group), 1645-1730; vendor fair #1, 1730-2030.

Wednesday, May 16. General session, 0800-1545; vendor presentations (third group), 1545-1630; vendor presentations (fourth group); vendor fair #2, 1730-2030.

Thursday, May 17. General session, 0800-1830; GE product fair, 1830-2100.

Friday, May 18. General session, D11/A10 steam turbines, 0800-1200.

Meals: Breakfast Tuesday through Friday, 0700-0800; Lunch Tuesday through Thursday, 1200-1300.

Budget info: Conference fee, $450 before April 15; hotel room rate, $149 plus taxes per night.

End notes: (1) The only vendors exhibiting on both Tuesday and Wednesday evenings will be the platinum and gold sponsors. (2) Questions regarding the conference or vendor fair? Email Sheila Vashi, 7F operations manager, at sheila.vashi@7fusers.org.

Day One

It was a long opening day. Some attendees gulped a quick cup of breakfast coffee and boarded busses at 7:30 for a tour of GE Energy's Houston shops, others were on the golf course by 8:00 (see p 33), still others participated in the special HRSG session from 8:30 to 12:30 conducted by technical experts from HRST Inc.

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- New Control Processor Chassis
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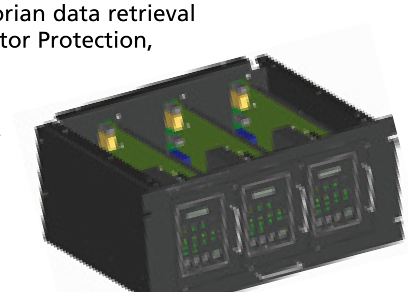

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In the afternoon, an hour-long introductory session designed to prep first-timers (perhaps one-third of the registrants) for the user-only discussion sessions on Tuesday and Wednesday preceded a two-hour OEM session on controls.

So when the 7F faithful mustered for the Keynote at 6:30 pm, the only thing between them and refreshments was G Michael Curley, manager of GADS Services for the North American Electric Reliability Corp. His message, in brief, was more operating data are wanted from generating facilities.

Talk about a tough assignment. But Curley was equal to the task. His mission was to give owner/operators a heads-up on NERC's proposal to collect reliability data and information on commercial generating units.

He began by reminding the users of NERC's mission: To ensure the reliability of the bulk power system. Curley said NERC has made great progress in this regard without undue burden on stakeholders by carefully evaluating what industry data are required to achieve assigned objectives, by reviewing and using to the extent possible available information resources, and by modifying existing programs as needed to meet goals.

In June 2010, he continued, the NERC Planning Committee created a task force to review if its Generating Availability Data System (GADS) should be mandatory reporting for all generator owners on the NERC Compliance Registry—specifically, all commercial generating units 20 MVA and larger or generating facilities 75 MVA and larger. Those in the room with gray hair recalled that NERC has used GADS to collect generating-plant availability information for nearly three decades.

The task force recommended that GADS be mandatory, Curley said, but at the same time suggested minimizing the amount of data collected by focusing only on those characteristics affecting bulk power system reliability. This would reduce by about half the information requirements of "full GADS," which many in the room were familiar with.

The GADS Task Force recommended using Section 1600 of NERC's "Rules of Procedure" for data collection. Under this procedure, GADS data collection is not governed by NERC standards and is not under NERC enforcement.

In fact, Curley added, NERC cannot apply financial penalties for delayed or incomplete reporting—or for not reporting any of the information requested. However, those companies not providing data would be in violation of the "Rules of Procedure" under Section 215 of the Federal Power Policy Act of 2005.

Late last summer, the NERC Board of Trustees agreed to a phase-in of the commercial generating units: 50 MW and larger starting Jan 1, 2012 and 20 MW and larger starting Jan 1, 2013. Note that the final rules are based on unit nameplate capacity only, not facility generating capability as originally proposed by the trustees and cited by Curley during his presentation before the 7F users. Curley told the editors in mid December that plants already reporting to GADS would see no difference in their reporting requirements now than they did before mandatory GADS.

1. Steering committee, 2011-2012

Chairman: Ben Meissner, *Progress Energy*
Vice Chairman: Sam Graham, *Tenaska Inc*
Treasurer: Peter So, *Calpine Corp*
Tom Berry, *TECO Energy*
Richard Clark, *SCE Energy*
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Dan Giel, *Progress Energy*
Jeff Gillis, ExxonMobil Chemical
Ken Gross, *Con Edison Co of NY Inc*
Art Hamilton, *Calpine Corp*
Bob Holm, *OxyChem*
David Such, *Xcel Energy*
Eugene Szpynda, New York Power Authority
Paul White, *Dominion Energy*

Day Two: Compressor section

The Houston technical program held with tradition. Informal presentations by users on compressor issues headlined the opening session, followed by open discussion (Sidebar 3). The first speaker, who has responsibility for eight 7FAs (7241s), told the group that eddy-current inspection of one unit, which had accumulated 942 starts and 14,000 hours of service since commercial operation began eight years ago, revealed 14 cracked S0 vanes. Two other GTs each had two vanes with cracks; another, one.

Eddy-current inspections are conducted semi-annually. Annually, dental molds are taken and each engine is borescoped to assess the condition of the compressor and to check for such things as vane platform-stepping and shim migration.

All cracked vanes described above were found in the lower half of their respective units, most between 5 and 7 o'clock; worst crack, 2 in. long, was found in the 6 o'clock airfoil at mid span. Rotor removal was required to extract the lower-half vane rows.

The gas turbines are located in a high-humidity environment and the vane rows were "welded" in place by rust. Online water washing and fogging were terminated in 2006. Analyses conducted by two independent engineering firms pointed to corrosion and loss of airfoil damping as the root cause of cracking. A user in the audience suggested there were other factors as well—perhaps thinning of the trailing edge.

S0, S1, and S4 vanes were replaced in the four affected gas turbines, S2 and S3 in three of the four. Plans are in place to remove OEM vanes in the four engines without vane distress during their next hot-gas-path inspections.

Replacement hardware was provided by a third-party supplier; the OEM never submitted a bid. Field service was performed by third-party contract personnel.

Inspection experience. The editors recalled a conversation with Rod Shidler of Florida-based Advanced Turbine Support Inc a month earlier when he said ATS inspection teams had found S0 cracking in at least three-dozen units during the last year, including one engine with fewer than 1000 fired hours and only 151 starts. He believes that perhaps no 7FA can be considered immune to S0 cracking. During a recent visit to a four-unit plant, he found three engines with cracked S0 vanes.

The consensus view of participants in the GE Roundtable at the CTOTF's Spring Turbine Forum was that S0 cracking is an emerging fleet issue and that every plant should schedule a borescope inspection when convenient. At that session, it was said that eddy-current inspection was successful in identifying S0 cracks; also that indications won't necessarily bleed dye during the alternative penetrant inspection. Attendees were urged to consult the latest version of Technical Information Letter (TIL) 1509.

Webinar. To be sure 7F owner/operators were up to speed on what may be the most important OEM advisories for plants with this engine, ATS developed PowerPoint presentations on TILs 1509, 1638, and 1795 and communicated the material via a December 14 webinar. Mike Hoogsteden and Dustin Irlbeck of ATS presented the material and CCJ ON*screen's* Scott Schwieger coordinated and produced the event. Turn to p 36 for an article summarizing the material disseminated.

Filter glop fouls compressor. The background facts: A 2 × 1 combined

cycle equipped with three-year-old horizontal conical/cylindrical inlet filters and no evaporative cooling system. Compressor cleaning was restricted to a semi-annual offline water wash. One day, GT 1 was found producing 27 MW less than its sister unit. Inlet filters were inspected and recorded as "wet." Pressure drop across the Unit 1 filters was double that across Unit 2's. Intermittent increases in engine vibration also were noted.

The engine was removed from service and inspected. Airfoils at the front end of the compressor were fouled with "sludge," those in the back of the unit covered with a white powder. There was so much sludge on the compressor blades, the user presenter said, you could grab handfuls. Standing water was identified just ahead of the air filters and just ahead of the trash screens.

The wet filters were sent out for inspection and evaluation. They were found loaded with spring pollen. Cooling-tower drift was identified as the source of the moisture. Drift never affected the sister unit simply because of Unit 2's more favorable location.

Two online water washes cleaned the sludge off the airfoils. No blade or vane damage was found. The vibration spikes were thought caused by clumps of sludge being released from upstream airfoils and impacting downstream rotor blades.

The fix: The conventional conical/cylindrical filters were replaced with triple-wrap HEPA (H12) filters and drift eliminators were installed ahead of the filter bank. It was too early to tell how effective the solution described is; the new filters had only been in service for a couple of weeks at the time of the meeting.

This case history introduced some serious discussion on the service life of filters, the viability of HEPA filters as an alternative to conventional ones, etc. A participant in the conversation said he has filters evaluated annually for effectiveness. At one of his plants, the results dictate changing filters every two to three years; at another, he believes he'll get to the second major (12 years) on the original filters. Note that prefilters are used at the second location and are changed quarterly.

The next presentation discussed R0 issues: biscuit rotation, blade staking, and erosion attributed to the OEM's SPRITS™ power augmentation system. The speaker representing a 2 × 1 combined cycle reported that the R0 biscuit mod had been implemented and that new R0 enhanced blades had been installed in March 2010. The latter had operated for 2000 hours and nearly 150 starts before inspection revealed a gap on one blade.

Closer inspection revealed that one blade had walked into the inlet guide vanes (IGVs) and started to machine itself. The contact was between the blade and the rub-ring area of the bellmouth. The biscuit had rotated 180 deg and allowed the blade to walk. Attendees were made aware that the recently released (Apr 25, 2011) TIL 1797 addresses the issue and advised to inspect at the next opportunity. In this case, experts believed staking was not sufficiently robust to deform the metal and lock in the biscuit.

The OEM was said to have told users that new R0 blades can tolerate erosion pitting because of the high compressive stress imparted by laser shot peening. Reportedly, as long as the depth of the pits does not exceed the depth of the peen—about 50 mils—allowable stresses will not be exceeded. Experience suggests that Sprits erosion will be about 10 mils after about 600 hours of fogging.

Don't forget the inlet screens. The final user presenter on compressors said that two 7FAs at his plant were found to have R0 impact damage. Small pieces of stainless steel wire were found in the inlet. Examination of the inlet screens revealed they were the source of the loose pieces of wire. The incident added seven days to a CI. The speaker urged his colleagues to make screens a key inspection point and not to hesitate replacing them when fraying begins. He also mentioned a redesigned screen was available, one less prone to causing domestic object damage.

Combustion section

An offshore owner/operator with four 1 × 1 7FA+e-powered combined cycles reported on a fractured diffusion-air pipe issue associated with a DLN2.6 combustor during the 2010 meeting. The underlying cause of the failure, he believed, was poor welding and high stress attributed to vibration. Further research and analysis were required.

The user returned this year to finish the story. The pipe, which had been repaired shortly before the 2010 meeting, broke again three months later. Comparison photos of the broken metal showed different failure patterns, leading the user to conclude that the cause of the second event was not the same as that for the first.

Vibration levels and the stress on the pipe were measured under varying operating conditions. Strain amplitude was found proportional to power output. The investigators concluded that high vibration was the primary cause in the first event and high-cycle fatigue secondary. For the second event, the primary cause was defective welding, vibration secondary.

Several more end covers were found with diffusion-air pipes having substandard welds and they were repaired. The OEM was challenged to investigate its design, manufacturing, and quality practices. The result: A welding process issue was identified and some quality-control procedures found inadequate. Related processes and procedures were under review at the time of the 2011 meeting and will be modified as necessary.

The user said engine vibration was reduced by use of balance shots. The unit, which had been operating at 3 mils is now running smoothly at less than 1 mil.

Automated combustion tuning. You can put a point on the electric power industry's technology timeline at 2011 for commercial acceptance by owner/operators of automated gas-turbine combustor tuning systems. That was the conclusion of the editors based on

2. 2011 sponsors

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presentations (user and vendor) and discussions at the 7F Users Group meeting.

The dry low-NO_x (DLN) combustion systems that helped gas turbines become the preferred generation alternative made users aware of "combustion dynamics." Recall that DLN combustion systems are prone to flame instability under certain operating conditions and the resulting pressure pulsations (dynamics) can be strong enough to damage both combustors and downstream hot-gas-path components.

To mitigate the destructive effects of these pulsations, OEMs participated in the development of combustion dynamics monitoring systems. The CDMS warns operators of impending instability, enabling them to make the necessary adjustments to maintain stable combustion.

The early CDMSs, which debuted only a few years ago, were "manual" systems. The ratcheting downward of emissions limits and plant staffs helped put the development of automated systems on the fast track. A user presentation updated the group on the status of tuning systems, which have automated the functions of the CDMS and integrated them into a controls package that assures optimal operation of the gas turbine on a continuous basis.

The user-presenter, who is the control system troubleshooter for a major F-class fleet, said he considered the following three tuning systems acceptable for powerplant use:

- PSM's auto-tune.
- Wood Group GTS's Ecomax™.
- The OEM's OpFlex™ AutoTune.

The controls expert said PSM's auto-tune was installed on three GE engines in his fleet, Ecomax on two. OpFlex AutoTune was not considered for deployment because of its cost, he added.

Most of the speaker's experience was with PSM's offering, which, at the time of the meeting, had accumulated more than 8000 hours of operation integrated with Mark V and Mark VI control systems. Performance has been validated in all seasons and at ambient temperatures from 20F to 100F. Feedback from the plants has been good, he said.

Benefits of the system, he continued, were these:

- Eliminates the need for seasonal manual tuning.
- Reduces the risk of lean blowout (LBO) events.
- Improves emissions control throughout the year.
- Minimizes combustion dynamics, thereby maximizing hardware life.
- Accommodates changes in gas properties while maintaining top performance.
- Expectations are the same basic system will be suitable for Siemens gas turbines as well as GE's. Development work on PSM auto-tune for the 501F is underway.

The PSM system, he continued, is customizable to meet the specific needs of each site. It is manufactured using industrial grade electronics, not Windows. Plus, it has an easy-to-use operator interface that is much like the Mark V screen.

Backgrounder. If you haven't yet had the opportunity to dig into automated combustion tuning, given its rate of implementation, this may be a good time. The technology is complex, but the field of expertise is relatively small. At the top technology ladder for land-based gas-turbine CDMS applications is Dr Timothy Lieuwen, PE, assistant professor, Georgia Institute of Technology, School of Aerospace Engineering.

Equally comfortable in front of a class, in the lab, or on the deck plates of a powerplant, Tim, the name he prefers, is a breath of fresh air in an industry ripe for new ideas. Lieuwen has developed algorithms for predicting when LBOs are likely. Jim Fenton of Termecula (Calif)-based FocusTek said the algorithms basically count events that are precursors to LBO. These events increase in number as the LBO condition is approached and that information is used both to generate warnings and change combustion-process variables to avoid a complete loss of flame.

San Diego-based Alta Solutions Inc makes the CDMS that underpins automated tuning systems such as PSM's. Lieuwen's algorithms are incorporated into Alta's offering for gas-turbine applications.

The company's AS-250 SpectralMon integrates advanced real-time monitoring and analysis with alarming criteria to detect changes in the dynamic signature of your engine. Once a dynamic event is detected, the system instantly informs the control system and records important data before and after the event. This information is used to change process settings and keep the engine "tuned."

Others are involved in the field as well. Siemens Energy offers an automated tuning package, KEMA FlameBeat is in the mix, and EPRI is working with Lieuwen and others to analyze the various tones produced by the combustion process. "It's all about the noise," says Leonard C Angello, EPRI's manager of combustion turbine technology.

Suggested reading at www.ccj-online.com to get you started: Click "Archives" on the tool bar at the top of the page and scroll to the issue indicated.

- 3Q/2006, "Monitoring—and mitigating—combustion dynamics."
- 2Q/2008, " 501F Users Group: Using advanced CDM analysis to improve reliability."
- 3Q/2008, "CDMS helps prevent forced outages, tune engine after overhaul."
- 3Q/2009, " 7F Users Group: "Non-OEM F-class operational improvements gain traction."

The editors followed up with a couple of plant managers to better understand how important automated combustor tuning might be to the reliable operation of their facilities. They said one of their primary concerns is the susceptibility of combustors to blowout of the lean flames required to maintain low NO_x emissions and acknowledged the promise of automated tuning in preventing LBOs.

The discussion revealed that blowouts are embarrassing to operations personnel, reflecting an inability to maintain optimal combustion conditions. Undesirable consequences of a trip include (1) a lapse in power production, (2) wear and tear on the engine, which can shorten maintenance intervals, and (3) the emissions penalties associated with restarts.

The reaction of top management is yet another consideration. The financial types who occupy the executive suites of unregulated generation companies may not be aware of the damage combustion dynamics can cause their engines,

3. Saluting the 2011 user discussion leaders, speakers

Ed Fuselier, *Direct Energy*
Bryan Graham, *Entegra Power Group LLC, Union Power Station*
Sam Graham, *Tenaska Virginia Generating Station*
Jim Harbaugh, *Tampa Electric Co*
Bob Holm, *OxyChem*
Shonosuke Koga, *Osaka Gas Co*
Robert LaRoche, *SRP*
Ben Meissner, *Progress Energy*
Dave Merkley, *Tenaska Inc*
Mike Sendlak, *Edison Mission Generation*
Tony Shook, *OGE Electric Services Inc*
Peter So, *Calpine Corp*
Paul White, *Dominion Energy*

but they certainly know when engine output drops to zero.

One of the plant managers who spoke to the editors said the gas turbines at his facility were prone to an occasional LBO while operators were getting used to the equipment during commissioning activities and shortly thereafter. However, since the units were tuned to rich PM3 with NO_x at about 10 ppm, and an alarm was installed to warn if NO_x drops to 7 ppm, there have been no incidents.

LBO generally is considered imminent by people knowledgeable on the subject when NO_x drops below about 6 ppm. Come up to speed on engine tuning and LBO by reading "Preventing blowout trips of 7FAs," which begins on p 16.

The plant manager said his engines are protected under an OEM long-term services agreement and are monitored by experts in GE's diagnostic center. Under the terms of this LTSA, the cost of an LBO trip would not be charged against the plant. Engine tuning, as necessary, is done from the M&D Center.

Another plant manager said GE monitors dynamics at all frequencies as part of the LTSA. He pointed out that this is just good business practice because it protects hardware that the OEM is responsible for under the contract. The engines he manages behave differently—some well, some not so well. They have unique personalities, he said, and the plant has experienced a couple of LBO trips over the years. One unit tripped shortly after it was tuned. "All tuners are not created equal," he added.

This facility pays for NO_x tunes—that is, when the NO_x level immediately downstream of the engine hits 7 ppm, a tune is ordered and conducted from the OEM's M&D Center. The cost for this service is in the low five figures. The manager said this approach was most cost-effective for them.

It appears there are no easy answers with respect to tuning, which is a seasonal requirement for most engines as the ambient temperature goes from cold to hot and from hot to cold. Automatic tuning may make sense given the successes reported thus far—provided your control system's capabilities are compatible with tuning system needs. However, there's an expense associated with adding this capability.

Does every plant need automatic tuning? Certainly not. Your decision will be based on many factors—including level of combustion system sophistication, emissions permit requirements, control-system capabilities, dispatch contract, etc. One plant manager recalled hearing about a generation company with dozens of legacy gas turbines and favorable emissions permits that operated its engines for years at ambients between 20F and 100F without ever tuning.

Contrast that with LBOs attributed to the sudden deep freeze that hit the Southwest early in 2011and contributed to the havoc on the Texas grid. Had automatic tuning solutions been in place perhaps some of those trips might not have occurred.

Not all LBOs can be prevented by tuning. Consider the disturbance initiated by a 138-kV fault that remained on the transmission system for about 1.7 sec. During the protracted fault, local voltage went to near-zero, which effectively reduced area load and caused generators to accelerate. Six DLN-equipped gas turbines tripped as a result of LBO.

Here's how that happened: As the machines accelerated in response to the frequency excursion, their compressors forced more air into the combustion chambers at the same time the governors reduced fuel input to reduce speed. More air and less fuel caused the flames in these engines to blow out and trip the units.

Onsite tuning is not cheap and sometimes it is inconvenient. Plants relying on manual tuning must get a technical expert to the plant as soon as operators see NO_x emissions drifting downward into the zone of "concern." The tuning may conflict with the affected unit's dispatch schedule and arrangements for alternative generation may be required.

As for the time it takes to manually tune an engine, one expert suggested plants plan for a one-day outage. Rarely, however, would you expect tuning to extend beyond a 12-hr shift. The simplest tuning assignments are for simple-cycle peakers that run at base load when in service. The tuner's primary concern is protecting against LBO at base load; combustion parameters can be forgiving on the ramp up and the ramp down. Such an assignment might take only four hours. Tuning a load-following peaker is more involved; dealing with a combined cycle having quaternary fuel and extended turndown is about the most complex assignment.

Turbine section

The moderator for the turbine session, one of the steering committee's senior members, had one slide: An assembly drawing for a 7FA turbine. The exploded view showed first-, second-, and third-stage turbine wheels and buckets (92 in each stage), 1-2 and 2-3 spacers, bucket lockwire, etc.

For each of the parts—including the nozzles, buckets, shrouds, and honeycomb seals associated with each stage—the moderator asked if anyone in the room had issues or experiences to share. Questions were relayed to the group for ideas and solutions. Wise move: With more than 200 7F engine experts on location, someone was almost certain to know how to solve a colleague's problem—and someone always did.

Keep in mind that the standard parts shown on the assembly drawing really aren't "standard." With 7221, 7231, and 7241 owner/operators represented at the meeting, and given the design variations within those model series, one or two people could be experiencing problems that no one else was. The group clinic approach to learning was a big success.

Safety practices, lessons learned

The steering committee had one voice when the subject of safety was introduced. The consensus view: The industry was doing a pretty good job regarding safety, but there certainly was more that could be done. Also, good communication is critical to a safe working environment.

One of the most interesting solutions presented involved making the turbine area safer for borescope inspections. Tie-offs, yo-yos, and conventional scaffolding are not quite right for inspection activities it was said. Some of the traditional options can be intrusive to the work being performed. Not the ideal.

A user presented on the design and installation of temporary access platforms that have served his company well. He showed a drawing of a six-section platform designed to cover the area between the engine split line and permanent grating. The aluminum sections are secured in place with turnbuckles. The platform system took two plant staffers about 80 hours to build. It can be installed for a borescope inspection in about two hours. For details, access http://ge7ea.users-groups.com.

Power and lighting required for gas-turbine maintenance was covered in the final presentation on Tuesday. After reading the title of his presentation, the speaker asked rhetorically, "What gets written up on every safety walk down during an outage?" Next, he wanted to know how many in the audience had not had any safety hits on extension cords in water or running through doors.

It's really simple, the presenter said, to safely provide for power and light. He showed the group how to line up electrical power when the gas

turbine was offline, how to install wall penetrations to bring power outside, where to place purchased boxes with multiple GFCI outlets (over-current protection on each) for easy access by maintenance personnel, the value of light strings with magnets for flexible out-of-the-way positioning, etc.

Safety initiatives are a top priority at the nation's generating plants powered by gas turbines. More than 35% of the entries received by **CCJ** for the journal's Best Practices Awards program in 2011 were for safety. Two years ago (2009), there were about half as many safety entries as there were in 2011; in 2007, there were about half as many as in 2009. This year (2012), the editors expect the safety entries to top last year's total.

Point is that if you're looking to see what others are doing to make their plants safer, the **CCJ** archives is a good reference resource. Access www.ccj-online.com and click on the "Archives" button in the top tool bar. Then access the details on each entry in the first-quarter issues of each year.

Day Three: Generators

It's no secret that the men and women who operate and maintain the nation's gas-turbine-based peaking, cogeneration, and combined-cycle generating facilities focus most of their attention on the GT. There's also the occasional holdover from the "age of fossil steam" to keep a sharp eye on the HRSG and steam turbine, if installed. But it's the rare plant that has a true generator champion, especially in these times of the ever-shrinking O&M staff.

This fact was not lost on the 7F Users Group's Steering Committee, which invited Mike Sendlak, manager of Electrical Engineering for Edison Mission Generation's technical support team to conduct a tutorial on generators Wednesday morning.

There was considerable pent-up demand for practical information on generators that could be brought back to the plant and put to use. And Sendlak was just the person to handle the assignment. Although an electrical engineer by education and now in a staff position, his heart is in the plant and with the equipment.

That Sendlak's presentation was toasted when his computer suffered a meltdown a few days before the meeting might not have been a bad thing for the users. He spoke without notes and in a casual manner, handling any question at any time and rapidly gaining the respect of an audience generally uncomfortable talking about generator technology.

Sendlak's presentation is not something that can be summarized here in the traditional sense because it was a tutorial designed to help users feel more at ease with generators and impart useful information along the way. He took attendees in directions they wanted to go based on questions.

Sendlak started by introducing 7F users to the various components of generators and discussing the basics: what a given part does, the kind of care it requires and how frequently, how it can fail and what happens if it does, etc.

Then he spent another hour or so discussing the variables to monitor online, the tests to conduct offline, the data to collect, etc. Perhaps the most important takeaway from this portion of the presentation was the importance of "trending, trending, trending" data to gauge machine health, better plan maintenance outages, and avoid forced outages to the degree possible.

If you weren't in Houston to hear Sendlak, you missed a valuable and constructive workshop. But most of the subjects he spoke to are covered in the comprehensive series of generator articles by Schenectady (NY)-based Consultant Clyde Maughan running in the **CCJ** (see p 40). Maughan is one of the world's leading experts on generator O&M. His series focuses on generator monitoring, inspection, diagnosis, and root-cause failure analysis. You can review the first seven articles at www.ccj-online.com/maughan.

To keep up with generator technology, consider joining the International Generator Technical Community at www.generatortechnicalforum.org. No charge. It features a robust technical library and online forums where you can get your questions answered by experts. Again, no charge.

Day Three: Auxiliaries

The auxiliaries session immediately after lunch featured two user presentations. The first described what is thought to be the first conversion of the OEM's gas-turbine control system to one offered by a third party; the second offered valuable experience with water-cooled liquid-fuel check valves on a dual-fuel 7FA. Details on the controls retrofit can be accessed at www.ccj-online.com, click "Archives" in the toolbar at the top of the page, click "2011 Outage Handbook" on the menu and scroll to "Industry first: Ovation replaces Mark V on 7FA."

Water-cooled check valves. There has been significant discussion over the years at meetings of several user groups regarding the coking problem many owner/operators of dual-fuel engines experience with standard liquid-fuel check valves. After switching from oil to gas, the oil remaining in check valves, which are located close to the combustors, is exposed to high temperature.

Above about 250F, that relatively small amount of oil oxidizes. The resulting coke coats check-valve internal surfaces (and fuel lines as well) and restricts the movement of valve parts. Once this occurs, a check valve will not open and close properly until it is overhauled.

The most common trip during fuel transfer is on high exhaust-temperature spread—caused almost exclusively by check valves "hung-up" on coked fuel. Startups on oil when fuel-system components are fouled can be challenging as well—sometimes impossible.

A user discussed the check-valve challenges encountered at his plant, then spoke about the corrective alternatives considered and five years of experience with the solution selected.

Four alternatives were evaluated for mitigating the coking problem to improve reliability. Here are the results of that investigation:

- Air cooling: Not possible because of space limitations.
- Lay-up the liquid fuel system after use and purge with nitrogen: Restricted operational flexibility. As much as a day might be required to prepare the fuel system for restart.
- Convert to a recirculating or return-flow liquid-fuel system to keep the oil moving and prevent coking. Financially burdensome. Plus, the Mark V control system had no spare I/Os to accommodate that upgrade.
- Change-out the conventional liquid-fuel check valves with water-cooled valves. The most cost-effective option. One valve required per can, a direct drop-in for the original. The only extra step was getting water for jacket cooling, but that was simple because a closed-loop cooling-water header was within reach.

The first and only issue encountered, inadequate cooling, was solved by removing a downstream restriction in the cooling-water discharge line. The water-cooled JASC (Tempe, Ariz) valves have been in service for about five years, the speaker said, and there have been no forced outages related to coking during that time.

Transfer and startup reliability with the OEM-supplied valves was less than 60%. Startup issues were almost all check-valve related; transfer reliability was affected by controls problems as well as coking. Today, the maintenance specialist continued, startup reliability is north of 95% and fuel-transfer reliability is more than 90%. CCJ

Preventing blowout trips of 7FAs

Technical presentations by vendor representatives are an important part of every 7F Users Group meeting. Fifteen presentations usually are made during five 45-min sessions. Having three presentations in each time slot virtually assures every user attendee will identify with at least one subject. These sessions are conducted in the afternoon, just ahead of the vendor fair, enabling follow-on discussion in the exhibit hall.

A presentation that got high marks from many users at the group's 20th anniversary meeting was Mitch Cohen's "Understanding and Reducing Lean Blowout Trips of 7FA DLN2.6 Combustors." Cohen is a respected senior systems engineer for Orlando-based Turbine Technology Services Corp.

Intermittent blowout trips, often referred to by the acronym LBO (lean blowout), are said to be relatively common for some DLN2.6 combustors not equipped with an appropriate advance-warning system or alarm. Negatives of LBO include accelerated degradation of parts and the obvious loss in kilowatt-hour production.

In his introductory remarks, Cohen said that LBO trips, which typically are annunciated by the control system as either "High Exhaust Spread" or "Loss of Flame" trips, do not always have a well-defined cause or clear-cut corrective action. Consequently, operators often restart their units only to suffer another LBO relatively soon.

He identified these potential sources of DLN2.6 blowout:

- Combustor tuned to a fuel/air ratio that is too lean.
- Low-frequency chug dynamics.
- Worn combustion-system hardware.
- Instrumentation failure or shift in calibration.
- Shift in control-valve calibration.
- Continuous emissions monitoring system (CEMS) out of calibration.

Note that the first two causes of LBO are tuning-related; remainder are a function of hardware condition.

Continuing, Cohen identified the following as LBO influence factors:

- Rich- or lean-PM1 operation.
- Ambient temperature.
- Unit configuration—that is, simple- or combined-cycle operation.
- IGV part-load temperature control curve.

Cohen's goal was to offer operators practical steps they could take during maintenance outages, combustion tuning, and normal operation to reduce the likelihood of an LBO trip. This included recommended guidelines for allowable emissions and dynamics levels to avoid blowouts and how the suggested values are influenced by split schedule and control curve adjustments. Cohen's tuning experience spans more than 50 7FA turbines.

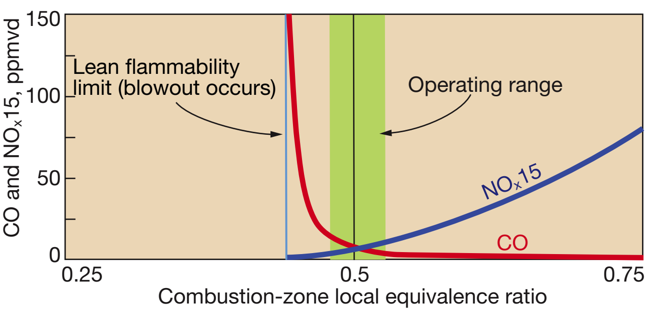
The information presented here does not disclose all of the tuning "tricks" the speaker shared with the three-dozen or so owner/operators who attended the presentation—this to protect his competitive advantage. However, it does provide operations personnel valuable insights on why blowouts occur and how to protect against them, as well as on how to distinguish between trips caused by LBO and dynamic instabilities.

A brief backgrounder on key combustion principles and the arrangement of DLN2.6 combustion systems precedes excerpts from Cohen's presentation to allow those unfamiliar with this equipment to benefit from his experience, which offers valuable lessons for all operations personnel.

The ABCs

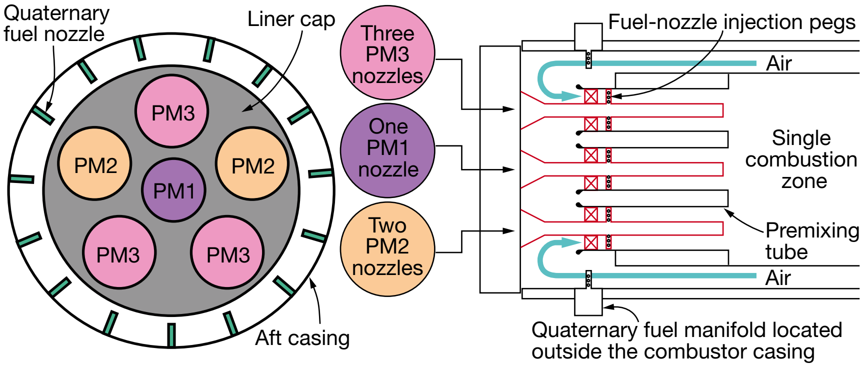
The DLN2.6 combustor, which is designed for 9 ppm NO_x, demands very tight control of the fuel/air ratio over the entire load range. Just how close this combustion system must operate to "the edge" to assure that emissions and performance goals are achieved is illustrated in Fig 1.

Note how near the *lean flammability limit* (LFL)—the point at which the fuel/air ratio is too lean to support combustion and LBO occurs—is to the desired operating range. Such close proximity suggests that if any one of a 7FA's 14 combustors operates to the left of the dashed line the turbine probably would trip.

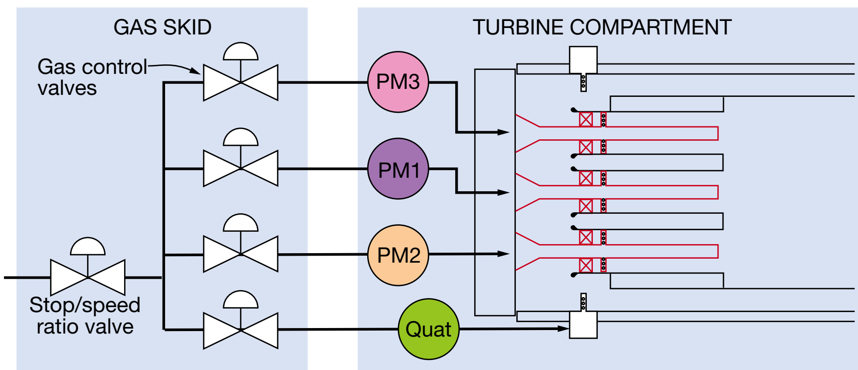


1. DLN combustion systems operate very close to the lean flammability limit and have a very narrow equivalence-ratio operating range

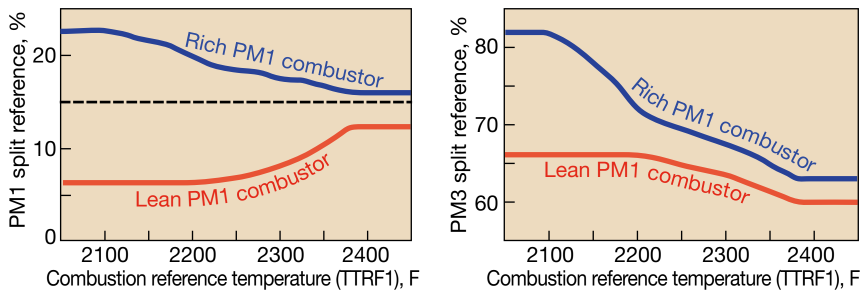
Equivalence ratio is another important term to remember. It is the actual fuel/air ratio divided by the stoichiometric fuel/air ratio. Recall that the defining characteristic of a diffusion flame is that fuel and air are introduced into the combustor separately and the mixture burns at an equivalence ratio of 1.0, where flame temperature is highest and NO_x production typically is highest as well.



2, 3. DLN2.6 fuel-nozzle arrangement is shown normal to the combustor axis at left, through the combustor axis at right. Premix burners of the same color are internally manifolded together within the end cover



4. Four gas control valves are arranged in parallel, each dedicated to a given fuel stream



5. Mode 6 split schedules for rich and lean PM1 combustors show how fuel flow is distributed among the various nozzles/manifolds as load changes. Typical PM1 split in Mode 6 is at left, PM3 at right

Above 1.0, there is fuel in the mixture that can't burn because the amount of air available is insufficient to support complete combustion. That's why high CO levels are a characteristic of fuel-rich flames. Below an equivalence ratio of 1.0, oxygen remains after complete combustion of the fuel and it serves to suppress flame temperature. A ratio of 0.5 means there's twice as much air as needed for complete combustion.

High CO is not just a characteristic of fuel-rich flames. It also may be found in lean flames because they are relatively cool and the conversion of CO to CO_2 slows as flame temperature decreases. CO ultimately limits engine turndown; the low combustion temperatures associated with low-power operation cause a rapid increase in CO level.

In the premixed combustion process used for DLE-equipped turbines, air and fuel are mixed upstream of the combustion chamber, allowing tight control of mixture stoichiometry and, therefore, flame temperature. Figs 2 and 3 show the arrangement of fuel nozzles for a typical DLN2.6 combustor. Note that the staging of multiple fuel streams through the six fuel nozzles is required to achieve turndown flexibility while maintaining flame stability, controlling NO_x emissions within requirements, and minimizing destructive dynamics.

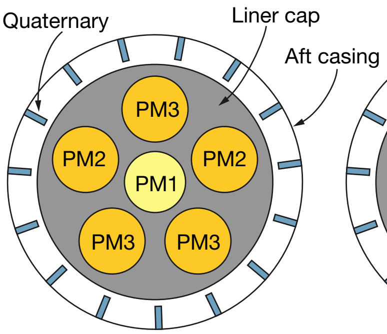
Premix (PM) burners of the same color in the diagram are internally manifolded together within the end cover. The quaternary, or fourth, fuel manifold (a ring around the outside of the combustor casing and upstream of the premix burners) serves the series of radial pegs shown in Figs 2 and 3. Quaternary is used on some units to reduce the amplitude of specific dynamic pressure frequencies responsible for wear and distress of the combustion hardware. The basic DLN2.6 layout in Fig 4 reveals four gas control valves arranged in parallel and served by a common stop/speed ratio valve. The three-way splitter valves found in older combustion systems are not used.

Cohen's presentation to the 7FA users essentially began at Fig 5, Mode 6 split schedules for rich- and lean-PM1 combustors, which shows how fuel flow is distributed among the various nozzles/manifolds as load changes. Recall that the term "Mode 6" means that all six fuel nozzles are receiving fuel. The horizontal scale, combustion reference temperature, varies with gas-turbine load: The higher the temperature, the higher the load. At base load, TTRF1 typically is in the range of 2380F to 2420F.

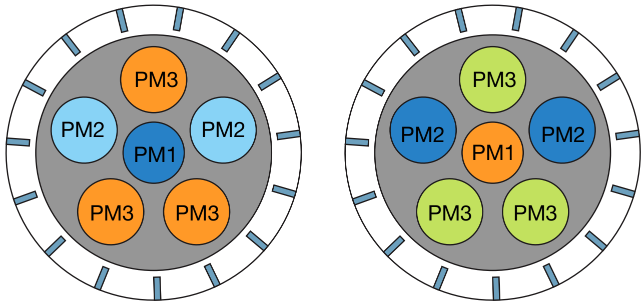
Cohen told the group that lean PM1 was the method of varying load on the gas turbine with the original DLN2.6 combustion system. In the left-hand chart of Fig 5, PM1 was at its highest split percentage at base load (extreme right) and dropped as the unit was unloaded (moving to left). Load turndown to about 50% of rated capacity was possible using this approach. Rich PM1 was developed after lean PM1 for the purpose of achieving greater turndown. It typically enables the combustion system to achieve a turndown of 40% or less while maintaining CO emissions within the desired range.

The dashed line at 15% of the PM1 split schedule represents the optimal split for NO_x in a DLN2.6 combustor—that is, the split at which minimum NO_x emissions can be achieved. The terms "lean PM1" and "rich PM1" are used relative to this split value. At a fixed firing temperature, NO_x increases as the split is modulated from this value in either direction—on the lean-PM1 side because the PM3 nozzles are getting richer and hotter; on the rich-PM1 side because the PM1 nozzle is getting richer and hotter.

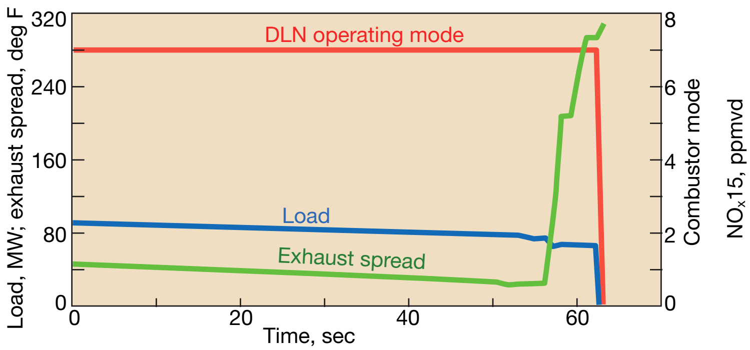
This is illustrated in Figs 6 and 7 for base-load and part-load operation, respectively. In Fig 6, all nozzles operate with fuel/air ratios above the lean flammability limit. For the lean-PM1 case at the left, PM1 is slightly leaner than PM2/PM3 (orangey-yel-



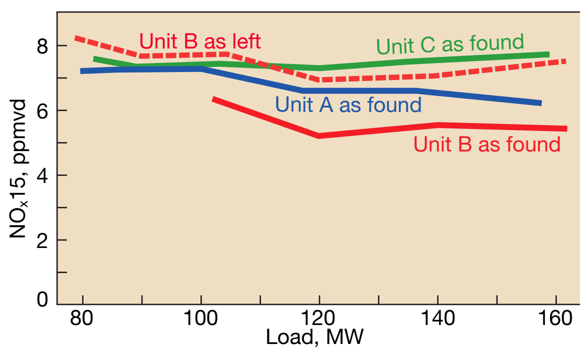
6. All fuel nozzles operate at fuel/air ratios above the lean flammability limit at base load. In lean-PM1 operation at base load (left), PM1 (light yellow tint) runs slightly leaner than PM2 and 3; in rich PM1, PM2 is slightly leaner than PM1 and 3 (right)



7. At part load during lean-PM1 operation (left), PM1 is the leanest nozzle, the PM3s are the richest nozzles and "anchor" the flame. The PM1 and 2 nozzles operate below the lean flammability limit. For the rich-PM1 combustor case (right), PM1 is the richest nozzle (flame anchor) and the PM2 nozzles are the leanest



8. Common LBO signature for lean PM1 combustor operation is characterized by a step change in exhaust temperature spread. Note that the change in exhaust spread from 25 to 209 deg F occurred within 2 sec while unloading in Mode 6; also that LBO occurred at 75 MW, just prior to transfer out of Mode 6



9. Increase NO_x to minimize possibility of LBO. B was the only simple-cycle 7FA at this three-engine site to suffer LBO repeatedly and the only unit with as-found NO_x below 6 ppm

low tint); for the rich-PM1 combustor at the right, PM2 is running slightly leaner than PM1 and PM3.

At part load during lean-PM1 operation, illustrated at the left in Fig 7, PM1 is the leanest nozzle and the PM1 and PM2 nozzles are operating below the LFL; the PM3 nozzles are the richest nozzles and anchor the flame. LBO is more likely to occur with this operating scheme than with the rich-PM1 scenario at the right where the single PM1 combustor anchors the flame.

Reason is that it's much easier to keep one nozzle above the LFL than it is to keep three above the LFL.

LBO with lean PM1

Cohen showed the group a common LBO signature (Fig 8), pointing out the characteristic step change in exhaust spread with no other anomaly identified in the trip log or in historical PI data. In this case LBO occurred at 75 MW, just as the engine was transferring out of Mode 6. The trip was not anticipated and occurred so quickly there was no action operators could take to prevent it.

At base load on the lean-PM1 split schedule, Cohen continued, all nozzles operate at close to the same fuel/air ratio and all nozzles, individually, are above the LFL. As the unit unloads, PM1 and PM2 are leaned out—eventually dropping below the lean flammability limit. PM3 must operate at a sufficiently rich fuel/air ratio to prevent LBO. An indicator of insufficient LBO margin, Cohen said, is very low NO_x values.

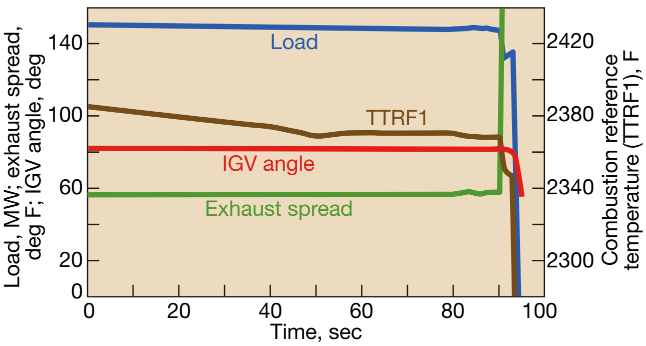
To provide adequate margin, he suggested not operating combustors at less than 6.5 ppm during part-load operation—even though in isolated instances, combustors with properly balanced, precision fuel nozzles can operate as low as 5 ppm without experiencing LBO.

Cohen illustrated the importance of having a generous "floor NO_x level" by reviewing LBO events at a site with three simple-cycle 7FAs operating in the lean-PM1 mode. When he arrived at the plant, Cohen found one of the engines (Unit B) operating at less than 6 ppm and the other two above 6 ppm (Fig 9). Unit B was the only machine to suffer repeated LBOs.

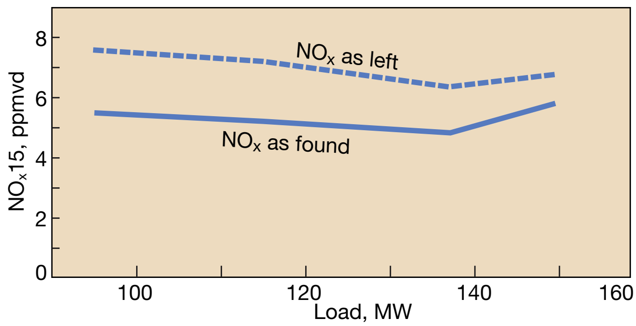
Problem was corrected by changing the PM1 and PM3 split schedules to increase combustor stability and eliminate blowouts. The split changes increased NO_x by 1-2 ppm (compare the Unit B as-found and as-left curves in the chart). The ability to make such precise tuning adjustments requires, among other things, an accurate NO_x analyzer in the gas-turbine exhaust stream, capable tuning personnel (on staff or outside consultants), and combustion components in good condition.

The skill of the tuner and his/her knowledge of how the engine will be operated and how it behaves under changing ambient conditions are critical to success. Fig 10 illustrates the point. It shows that units can be tuned too lean. Here an LBO trip occurred on a gas turbine at only 3 MW below base load as the gas turbine was being unloaded. The exhaust-temperature spread changed from 57 to 274 deg F within 1 sec. What happens during load reduction is that the change in fuel flow is instantaneous but the inertia of the GT rotor keeps air flowing at a high rate—in this case reducing the fuel/air ratio below the lean flammability limit in at least one of the combustors.

Cohen stressed the point that



10. Units can be tuned too lean and LBO can occur even at high combustion reference temperatures close to base load. Chart shows an LBO trip on a unit operating at only 3 MW below base load. Note that the exhaust temperature spread changed from 57 to 274 deg F within 1 sec while unloading



11. The combustor in Fig 10 was tuned very lean. NO_x was less than 6 ppm at all loads with the lowest level, less than 5 ppm, identified at just below base load (where LBO occurred). Changes to the PM1 and 3 split schedules increased NO_x by 1 to 2 ppm thereby increasing combustor stability and eliminating LBO

LBO can occur at any load within Mode 6 if the unit is not well-tuned. When he arrived at the site, he found NO_x in the engine exhaust at less than 6 ppm at all loads and minimum NO_x at less than 5 ppm just below base load, where the LBO occurred (Fig 11). Solution, as before, was to increase combustor stability by making changes to the PM1 and PM3 split schedules to increase NO_x by 1 to 2 ppm.

Cohen noted that sites having SCRs often do not pay close attention to engine NO_x emissions; operators focus on stack NO_x levels, which are reported to environmental authorities. In such cases, it's easy to overlook conditions conducive to LBO. The diligent tuning specialist, he continued, reviews unit historical data to see how NO_x has varied with ambient temperature changes over the life of the unit, and what influence such variables as the shape of split schedules and the shape of the IGV part-load temperature control curve have on the NO_x/ambient relationship. Some units, Cohen pointed out, are able to operate throughout the year without requiring seasonal tuning, but this is exception rather than the rule.

Chug-induced blowout with lean-PM1 combustors

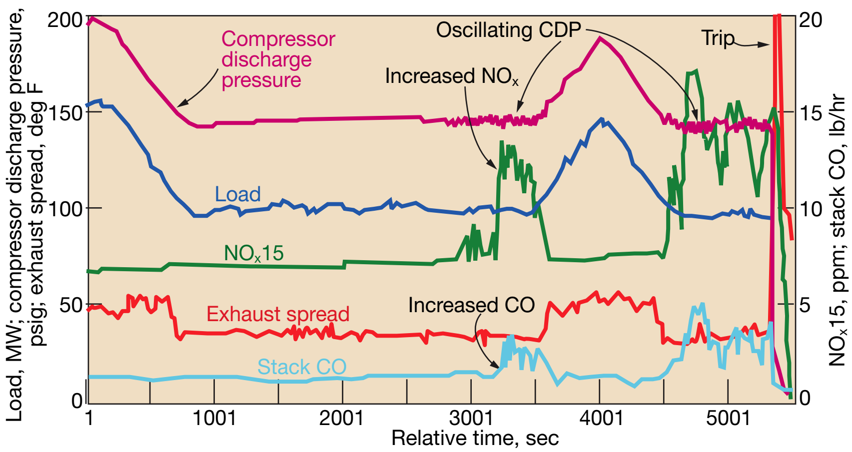
So-called "chug" describes a low-frequency (15-18 Hz) dynamic mode capable of causing a blowout trip. Cohen said many 7FA users refer to this phenomenon as LBO dynamics; however, the mechanism of blowout really is a different phenomenon than LBOs caused by burners falling below the lean flammability limit, as described above. Chug-induced blowout is a trip driven by a dynamic instability which can occur at elevated NO_x levels—7 to 8 ppm—that do not suggest operation below the LFL.

These two modes of blowout can occur independently of each other. A distinguishing characteristic of chug tones is that when they are present at amplitudes as low as 0.5 psi peak to peak, they can be heard as a low rumble and felt as floor vibrations when standing near the turbine. This is in contrast to 140-Hz hot-tone dynamics (the primary tone responsible for component wear) which cannot be sensibly heard or felt—even at amplitudes of 5-10 psi peak to peak.

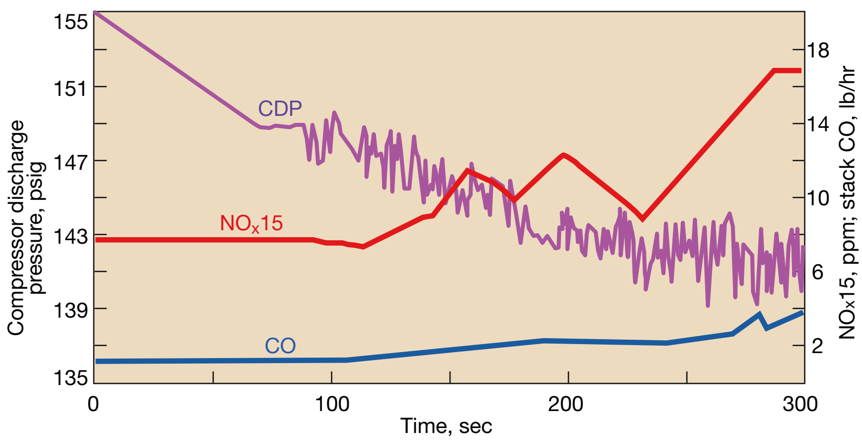
Another characteristic is that both lean- and rich-PM1 combustors are susceptible to chug-induced blowout. Cohen said he could not recall seeing or hearing of any LBOs on rich-PM1 combustors in which the combustor falls below the lean flammability limit as indicated by very low NO_x emissions. The PM1 nozzle in the rich-PM1 configuration operates richer than the PM3 nozzles do in the lean-PM1 configuration, he added, more reliably anchoring the combustor and preventing LBO trips.

Fig 12 illustrates a chug-induced blowout of a lean-PM1 combustor. Comparison with Figs 8 and 10 shows it does not resemble classic LBO caused by burners falling below the LFL. Note the intermittent and unsteady increases in NO_x and CO preceding the trip, coupled with highly unusual oscillations in compressor discharge pressure.

CDP oscillations of up to 5 psi max to min correlate closely with increases in NO_x and CO (Fig 13). Although not shown in the graph, detailed data review showed that the CDP oscillations were not being driven by oscillations in the inlet guide vanes, the inlet bleed heat system, or the fuel system. When the unit was



12. Chug-induced blowout is driven by a dynamic instability. The incident described in the chart occurred with a lean PM1 combustor and does not resemble classic LBO caused by burners falling below the LFL

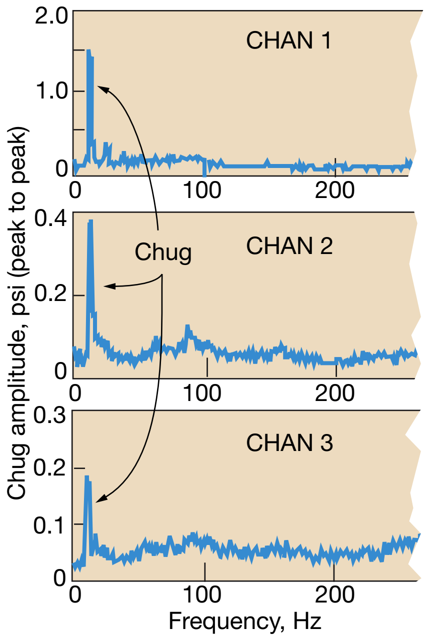


13. CDP oscillations in Fig 12 are shown in greater detail here. Oscillations of up to 5 psi max to min correlate closely with increases in NO_x and CO tuned, relatively low-amplitude chug dynamics (Fig 14) were present and were found to be the driver of both the CDP oscillations and the blowout of the combustor.

Cohen said amplitudes on the order of 1 psi peak-to-peak are capable of causing the combustor to blow out. Clearly, having a combustion dynamics monitoring system (CDMS)—which was not installed on this unit—can help identify chug before blowout occurs. But plant personnel must be trained to identify the phenomenon. Fig 15 shows that for the lean-PM1 case illustrated, increasing chug amplitude prevented operation at loads lower than 135 MW. Note the abrupt end of the chug as-found curve. Retuning of the unit significantly reduced the chug amplitude (to less than 0.2 psi peak to peak) and restored the turndown capability to 50% load.

Chug-induced blowout with rich-PM1 combustors

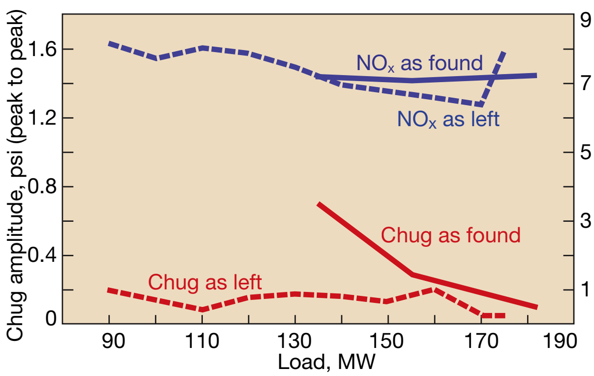
As noted previously, rich-PM1 combustors, while virtually immune to LBO trips caused by combustors falling below the LFL, are susceptible to chug-induced trips. Fig 16 describes the chug-induced trip of a rich-PM1 combustor. Two 7FAs at this simple-cycle site experienced three such trips over a three-day period, each characterized by a sudden increase in exhaust spread. There were no obvious causal indications in the trip log and NO_x was in the 7-8 ppm range—above the level one would expect classic LBO.



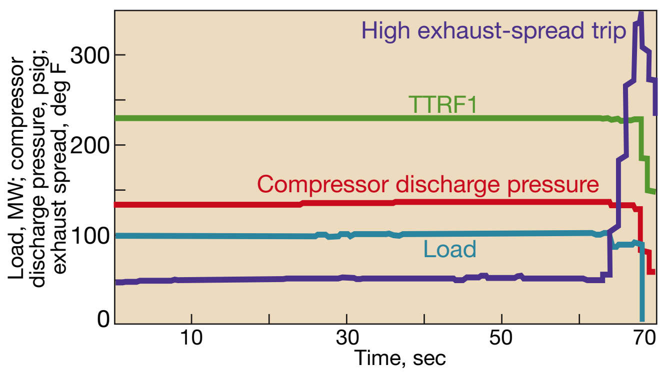
14. Chug, a low-frequency dynamic mode, can be an indicator of imminent blowout. Having a dynamics monitor helps by identifying chug before a blowout happens

Historic dynamics data (15-sec average) in Fig 17 offer a closer look at the chug-induced trip described in Fig 16. The data plot for combustor can 9 on one of the affected engines shows repeated bursts of chug tone shortly before the trip. Can 9 had the highest amplitude among the 14 installed on the 7FA (0.8 psi peak to peak) when the trip occurred, although all cans exhibited chug tones. Because the data are presented as a 15-sec average, it is possible—perhaps likely—that the instantaneous amplitude at the moment of trip was greater than 1 psi.

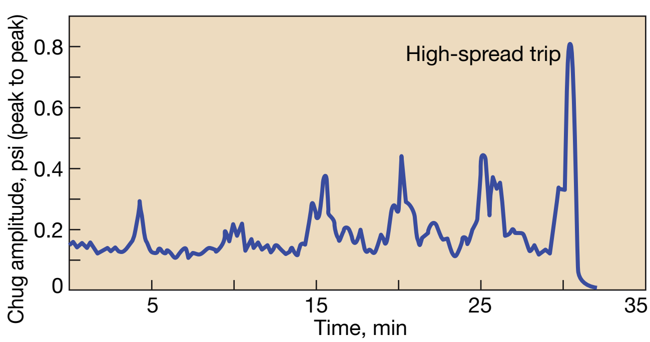
As with the lean-PM1 case history that preceded this one, retuning of the unit eliminated the susceptibility to chug-induced blowout by lowering dynamics from 0.6 psi to less than 0.2 psi peak to peak (Fig 18). Note that NO_x emissions were about the same before and after tuning—between about 7 and 8 ppm.



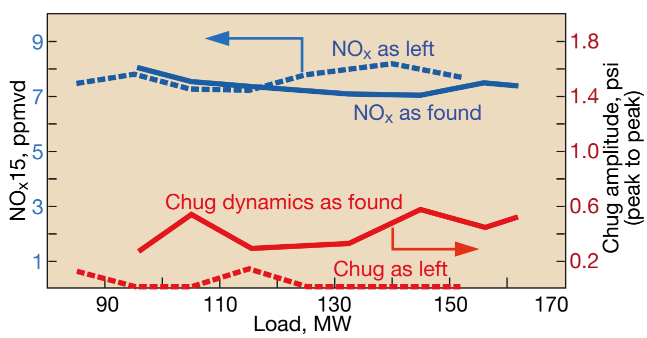
15. Chug dynamics are reduced through specific split schedule changes. For lean PM1 case illustrated, increasing chug amplitude prevented operation at loads lower than 135 MW (solid as-found curve in chart)



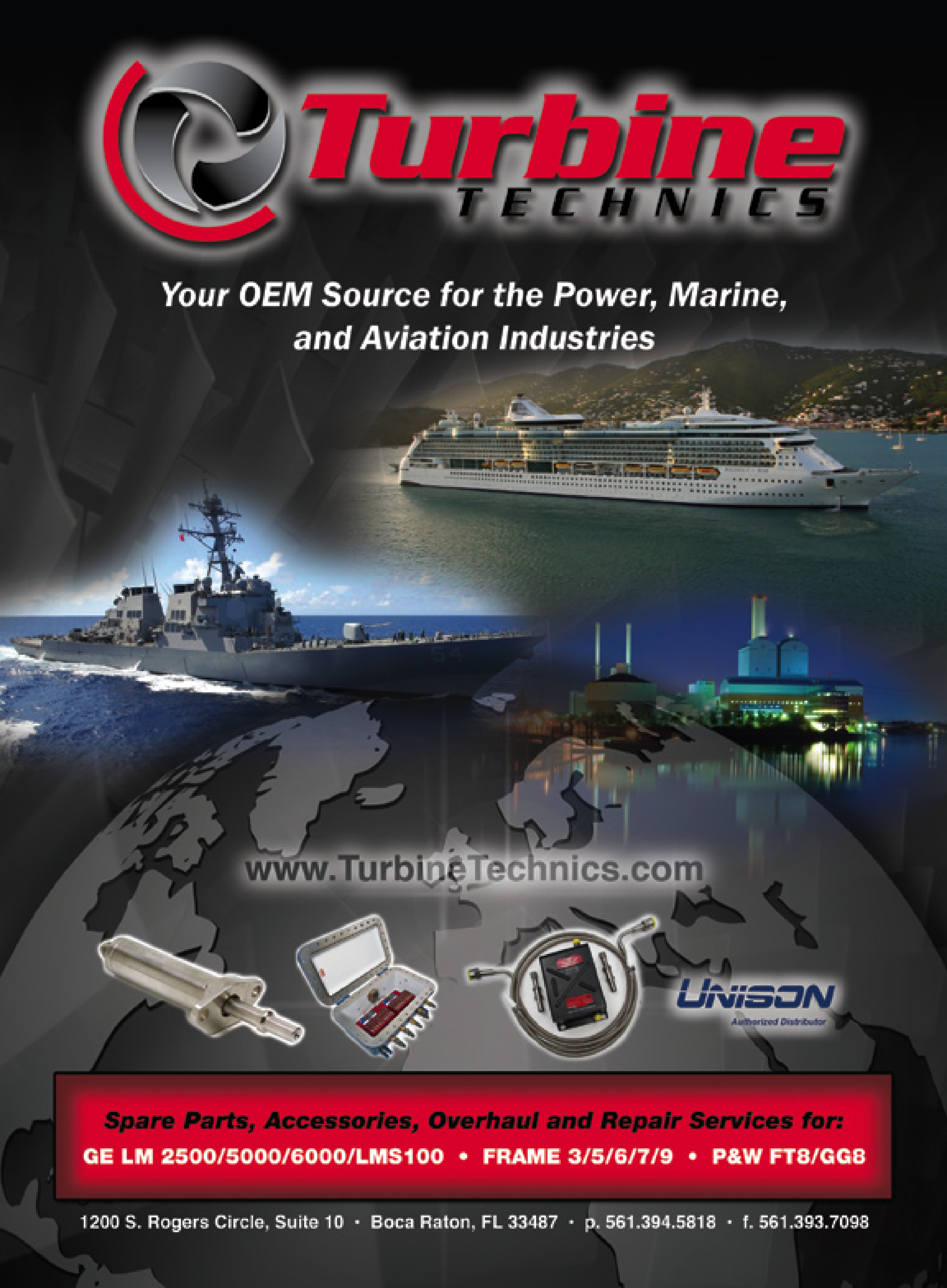
16. Rich PM1 combustors, while virtually immune to LBO trips caused by combustors falling below the lean flammability limit, are susceptible to chug-induced trips. No PI data were available at this simple-cycle site, but good dynamics data were

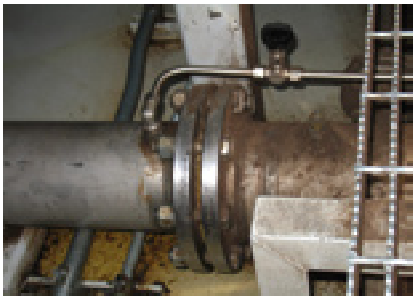


17. Historic dynamics data (15-sec average) offer a closer look at the chug-induced trips identified in the previous illustration. The data plot for combustor can 9 on one of the affected engines shows repeated bursts of chug tone shortly before a trip occurred



18. The susceptibility to chug blowout was reduced dramatically by lowering dynamics from 0.6 psi to less than 0.2 psi peak to peak. NO_x emissions were about the same before and after tuning—between about 7 and 8 ppm





19. **Oil is supplied** to the LO pump thrust bearing via a connection on the discharge piping (above)

20. **F-class rotor shop** at the top of the figure allows for 50 ft under the 80-ton hook (right)

Other vendor presentations

American Surface Modifications LLC, www.asm-llc.com, *On the nature of coatings for F-technology components,* Purush Sahoo, Francis Dinh, and Randall Martin.

Degradation of hot-section components can be problematic for owner/operators and result in financial penalties associated with downtime and loss of efficiency. Coatings are critical for mitigating degradation mechanisms—including high-temperature oxidation and hot corrosion. Speakers shared operating experiences of different types of coatings by way of case studies.

Buffalo Pumps, www.buffalopumps.com, *Evolution of Buffalo Pumps on the GE 7F turbine package,* Scott Lombardo.

Presentation focus was the design evolution of lube-oil pumps for both gas and steam turbines. Extending the interval between thrust-bearing replacements has been one of the company's primary goals over the last several years. First phase of this program was a redesign of the bearing housing to accommodate a 16,000-hr interval. All pumps sold since 2004 are so equipped. For the installed base, the company developed a complete drop-in replacement pump end which can be installed in the field or in the factory.

A 2007 design upgrade switched the thrust-bearing lubricant from grease to oil, supplied via a connection on the pump discharge (Fig 19), thereby extending the bearing replacement time to 30,000 hours and completely eliminating the need for periodic repacking of the bearing with grease. This mod also can be done in the field or in the factory.

Donaldson Company Inc, www.donaldson.com, *Understanding the ASHRAE 52.2 filtration efficiency testing standard and other key factors that should be considered when evaluating inlet filtration options,* Bill Goodson and Barry Link.

Plant personnel may not have a say in the selection of inlet-air filters for new peaking and combined-cycle plants, but they certainly are involved in choosing replacements. The Donaldson presentation was valuable for updating users' understanding of important variables and key filter performance data—including ASHRAE 52.2 test reports. It began with a review of the different types of media, discussed particle removal efficiency, explained dust holding capacity, and addressed filter life.

Of particular value to 7FA owner/operators in attendance was the importance of understanding your specific application. Goodson and Link pointed out that an air filter performs differently at different air flows and in different configurations. They said that the configuration of the inlet system and the air flow a filter module handles can have a major impact on its performance.

The speakers compared a variety of designs offered by Donaldson for 7FA service—including vertically mounted self-cleaning cylindrical filter elements, self-cleaning conical/cylindrical filter element pairs mounted horizontally, static conical/cylindrical filter element pairs mounted horizontally, and Wave™ panel filters of varying depth.

The presenters then reviewed factors that can impact filter performance and life. They started with location/ambient environment, commenting on relative humidity, liquid water (fog and rain), snow and frost, hydrocarbons, concentration of ambient dust, and varying environmental conditions.

Another factor they discussed was the gas turbine's operational profile: The number of hours your engine operates can impact filter selection.

The importance of ASHRAE 52.2 to users for comparing the performance of alternative filter offerings was stressed. The standard guides determination of an air filter's resistance to air flow and its ability to remove contaminants from the air stream. Goodson and Link explained how filter performance is evaluated with a standard dust and how the MERV (Minimum Efficiency Reporting Value) is determined. A sample test report was explained and provided to attendees.

Users unable to attend the Donaldson presentation can get a copy of the paper prepared especially for the meeting by emailing filterinfo@donaldson.com.

D-R Leading Edge Turbine Technology Services, www.dresser-rand.com, *Latest technical solutions for F-class component repair and refurbishment,* Greg Snyder.

Snyder provided insights into D-R LETTS' latest technical solutions for F-class component repair and refurbishment. A description of the company's new F-class rotor shop, which will add to the comprehensive lineup of repairs and services already offered, was included. The state-of-the-art addition will increase shop lifting capability to 80 tons and 50 ft under hook, with provision for future growth (Fig 20).

F-class rotors require a fully equipped world-class facility, engineering capability, and top technology to successfully resolve the unique issues associated with these high-tech designs. Dresser-Rand's available resources and commitment to excellence are driving the

development of alternative service and repair solutions that few others can provide, Snyder told the group.

These same capabilities also can help owner/operators better manage their rotors up to—and possibly beyond—the original design lives of those components. Successful continued operation can be achieved through a combination of inspections, high-end analyses, and repair and parts solutions.

The enhanced capability offered by the new facility will help DR-LETTS provide the user community access to a high-tech one-stop shop. By adding parts, field service, and control offerings to our existing engineering solutions, Snyder said, we continue with the company's commitment to provide the industry very attractive low-cost alternatives.

Gas Turbine Efficiency, www.gtefficiency.com, *Automation of gas turbine performance,* Chris Soileau.

Soileau followed up on a 2009 presentation to the 7F Users Group by a team of engineers from Entegra Power Group LLC (CCJ, 3Q/2009) that described how Gas Turbine Efficiency's ECOMAX™ gas-turbine optimization system allowed them to improve performance and increase power output without exceeding OEM design limits.

He said that ECOMAX allows continuous tuning of the gas turbine without external operator intervention. Predefined selectable parameters, determined by the plant operator, allow flexible matching of turbine performance with operational goals. Experience of several natural-gas-fired 7FA Model 7241 turbines equipped with the system, has been favorable, Soileau added. Benefits include: more power, tighter control of combustion and emissions, and elimination of seasonal tuning and tuning following combustion and hot-gas-path inspections.

Software add-ons for enhancing turbine operation were part of the presentation. These included firing-curve adjustments to OEM preset limits, turndown, and startup emissions optimization.

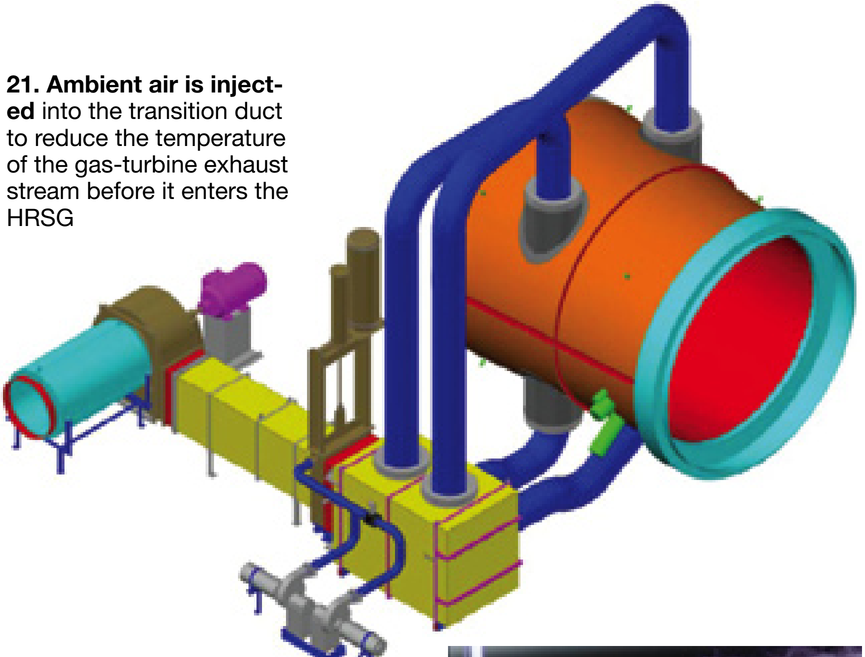
HRST Inc, www.hrstinc.com, *Quenchmaster: The solution to desuperheater overspray,* Amy Sieben.

Sieben began by reminding users that low-load operation can be detrimental to the health of their HRSGs. Reason is that for some gas turbines—such as the 7FA—exhaust temperature increases at low loads. More specifically, the exhaust from a 7FA can be as high as 1200F at loads from about 30% to 70% of rated output.

Operation in this range can cause over spray in interstage desuperheaters as the control system calls for more water to reduce excessive steam temperature. Over spray is conducive to fatigue damage in large-bore piping downstream of the desuperheaters if the pipe undergoes a large, sudden temperature drop associated with the over-spray event.

Sieben suggested air attemperation as a means of reducing GT exhaust temperature before the gas enters the HRSG's high-temperature harps. Here's how HRST's QuenchMaster™ works: Significant amounts of ambient air are injected into the transition duct between the gas turbine and the HRSG inlet duct to reduce the temperature of the exhaust stream entering the boiler (Fig 21). The amount of air flowing into the system is adjusted to maintain a specific range of superheat for both main and reheat steam.

The temperature of the air/exhaust gas mixture is set to maintain acceptable metal temperatures in the HRSG and steam turbine, and the interconnecting piping, within a "safe" range without having to use water for attemperation. Access "Air attemperation protects HRSGs against damage at low loads," 1Q/2011, at www.ccj-online.com.



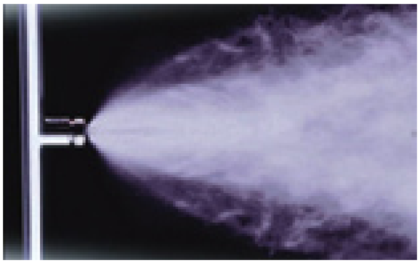
21. Ambient air is injected into the transition duct to reduce the temperature of the gas-turbine exhaust stream before it enters the HRSG

Mee Industries Inc, www.meefog.com, *Inlet fogging on GE 7F gas turbines,* Thomas Mee.

Fogging has become a popular evaporative technology over the last decade because it is capable of cooling gas-turbine inlet air to its wet-bulb temperature, making the technique more effective than wetted media (evap coolers). Although fogging has been associated with compressor wear and tear at some plants (erosion of blades in particular), in virtually all instances this was said to have occurred because of poor design, fabrication, and/or installation, and/or improper O&M of the fogging system.

Mee began with a brief discussion of factors critical to the design of an effective fogging system. Droplet size is of primary importance, he told the group, because small droplets evaporate quickly (Fig 22). Those too large to evaporate in less than two seconds—the approximate time it takes air passing through the inlet filters to reach the compressor—will either fall out on the duct floor or enter the compressor.

Location and arrangement of the fog nozzles was another discussion point. He noted that the OEM-recommended placement for fog nozzles, at least on older machines, generally does not allow sufficient time for droplet evaporation and can lead to flowing water at the compressor inlet.



22. Effective, problem-free fogging requires very small droplets to promote rapid evaporation

Mee illustrated the point with a CFD plot to show the large variation in air velocity across the inlet ductwork. The message: Velocity must be considered by designers in the placement of nozzles to avoid localized over-saturation. Translation: More nozzles are required in high-velocity areas than in low-velocity regions of the ductwork.

Mee continued with recommendations for positioning (1) gutters and drains to minimize the probability of free water gaining access to the compressor and (2) trash screens to prevent condensation of fog and the formation of large droplets close to the compressor inlet. To learn more, access "To fog or not to fog: What is the answer?" 3Q/2008, at www.ccj-online.com.

Meggitt Sensing Systems, www.meggittsensingsystems.com, *Microwave blade-tip monitoring system,* Tom Holst.

Blade-tip sensors monitor blade vibration and tip clearance in real time, enabling meaningful machinery diagnostics and identifying the optimal time for maintenance. Blade vibration is derived from high-resolution blade-tip timing measurements taken by multiple microwave blade-tip sensors. Long-term tracking of individual blade resonance frequencies and magnitudes facilitate blade health monitoring. Changes in blade resonance, Holst said, clearly identify degrading stiffness characteristics caused by an increasing level of damage.

He added that this technology is particularly well suited to measuring 7FA R0 and R1 blade damage through changes in measured natural frequencies of blades. Such capability helps plant personnel optimize the unit's inspection schedule and minimize the chances of a catastrophic failure. Also, it can help avoid rubs on restarts.

National Electric Coil, www.national-electric-coil.com, *A review of critical generator issues for outage planning,* Howard Moudy.

Moudy ran through a checklist of items owner/operators should consider prior to scheduling a maintenance outage. Owners' priorities of cost, outage time, and long-term reliability can be satisfied with proper inspection and planning. Typical concerns regarding air-cooled generators include the following:

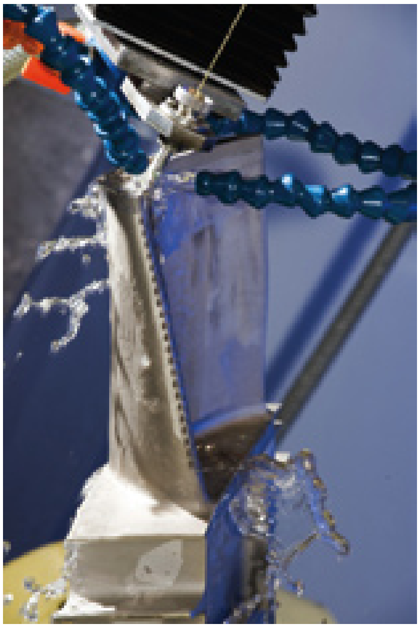
- Stator and rotor. Contamination and insulation deterioration.
- Stator. Partial discharge (PD) and spark erosion (SE), slot wedge looseness, core issues, looseness/movement, endwinding resonance/looseness.
- Rotor. Conductor and joint issues, main lead/connectors (pole to pole).

A series of photos enabled users to differentiate between stator PD and SE (early and advanced stages), see rotor and stator contamination, identify and correct slot wedge and endwinding looseness, identify blocked ventilation passages, locate shorted turns, etc.

Planning, performing, and documenting generator outages was Moudy's next topic. The generator expert called for a proactive effort on the part of owners and operators. This included the following:

- Identifying qualified vendors and establishing blanket terms and conditions. Be prepared for sticking points in the areas of indemnification, limitation of liability, warranty, termination.
- Bone up on design of your machine and its maintenance requirements. Document and trend generator information. Talk to user-group colleagues with the same generator about their experiences.
- Develop performance-based specifications.
- Plan, plan, plan to assure a successful outage. This includes planning for emergencies and the unexpected.

Power Engineering Services & Solutions Inc, www.pessweb.com, *Increasing profitability of the MS7001FA gas turbine through thermal optimization,* Miguel Sernas.



23. **Tools** capable of implementing advanced repair schemes provides refurbished parts that in some cases are better than the original

Sernas explained concepts related to instrumentation, thermodynamic design, control system philosophy, and degradation mechanisms to help plant operations personnel keep their units running at top efficiency.

Pratt & Whitney Power Systems, www.pw.utc.com, *Advanced 7FA component repairs proven from standard work developed for commercial and military aero repairs,* Andy Lutz, Mat Gartland, and Jose Quinones.

PWPS differentiates itself from repair facilities that merely "fix" parts. Its representatives stressed both an approach to engineering of repairs to address the root cause of field problems and facilities having the tools to implement advanced repair schemes (Fig 23). The company pursues design improvements with the goal of providing refurbished parts that are "better than the original," where possible, the speakers said.

The collaborative process of continual 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. Examples of successful advanced repair engineering and execution were provided.

PSM, www.psm.com, *7FA+e compressor durability upgrade package offerings,* Tim te.Riele.

Focus of the presentation was the company's design evolution for its 7FA compressor upgrade. It was designed to show owner/operators what PSM has identified as the OEM's field issues and how they can be eliminated with the company's R0 upgrade and its S0-S4, S13-S16, and S17/EGV package upgrades.

Dozens of sets of PSM R0 blades—both flared and unflared designs—are installed at customer sites and many more are on order. Rigorous field validation was said to confirm the ability of these airfoils to operate without restrictions regarding fogging and online water washing. No periodic leading-edge dental molds are required.

The PSM R0 design is said to offer the following design enhancements over the OEM's airfoil without changing aerodynamic performance or adversely impacting engine performance:

- Higher-strength alloy material.

- Undercut attachment to address fretting concerns.
- Modified airfoil thickness to retune the blade.
- Blade frequency increased above the machine's operating range to reduce its vibratory stress response by more than 50%.

Regarding the problematic S0-S4 compressor stators, PSM now offers these rows for flared 7FA+e machines on commercial terms. The company says it has upgraded the S0-S4 design to prevent the lock-up of ring segments experienced by many users, thereby reducing the potential for high-cycle fatigue and the possible liberation of some stator vanes. Enhancements include smaller carrier segments, addition of a groove in the carrier to accommodate tooling that facilitates disassembly, and a switch to a higher grade alloy to reduce the potential for corrosion and lockup. Plus, non-uniform spacing of vanes has been incorporated into the S0 and S1 stator rows to reduce the vibratory response of R0 and R1 rotor blades.

Tetra Engineering Group Inc, www.tetra-eng.com, *HRSG performance analysis: Impact of low-load GT operation,* Frank J Berte.

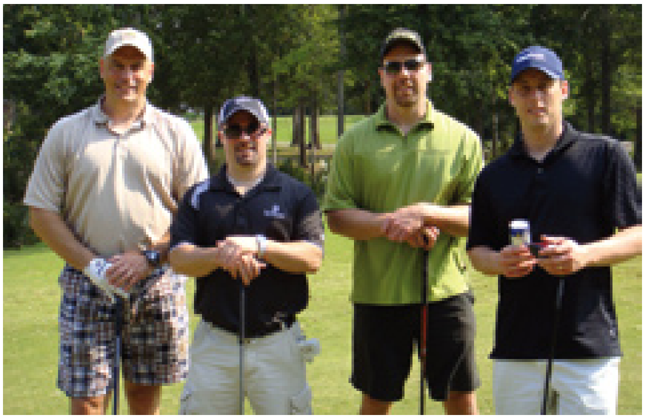
Berte alerted owner/operators to "flexible plant" operational impacts on heat-recovery steam generators. He began by defining "flexible" as extended turndown of the gas turbine while maintaining required emissions levels; faster startups, shutdowns, and ramp rates; and extended duct-burner range and turndown. An expert in boiler design and operational modeling, Berte talked about impacts on steam temperature control, flow stability, changes in gas-side flow, range limits on control valves, etc. The speaker suggested that users consider evaluating their HRSGs under possible future operating scenarios, and if current capabilities are not compatible with requirements predicted for tomorrow, to begin looking at what mods would provide the flexibility required.

Veracity Technology Solutions, www.veracityts.com, *Mitigating the risk of compressor failures through the use of advanced nondestructive inspection methods,* Kevin McKinley.

McKinley described advanced nondestructive examination techniques as a core component of the company's 7FA inspection program designed to identify and mitigate operational risks. CCJ

Winners all

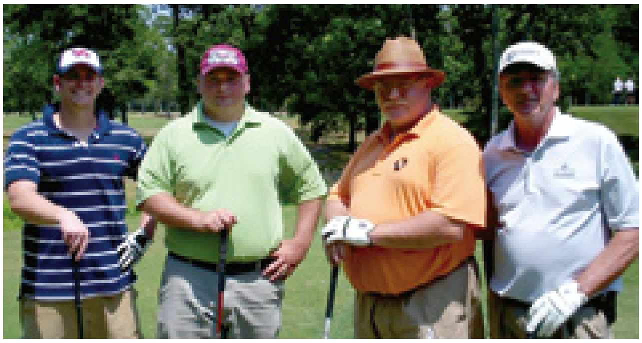
Dan Krick, Arlington Valley Energy Facility; Adam Wooster, TOPS LLC; Peter Geissler, LS Power Group; Fred Price, Allied Power Group (left to right, all photos)



William Dollard, AGT Services Inc; Brian Jones, AGT Services Inc; Kevin Bruce, Brighton Beach Power LLC; Jay Hrynyk, Brighton Beach Power LLC

Lee Wood, Wood Group GTS; Brian Ennis, Wood Group GTS; Brian English, TECO Energy Inc; Jake Hall, TECO Energy Inc

Paul Bruning, Puget Sound Energy; Gerald Klug, Puget Sound Energy; Robert O'Neal, GE Energy; Todd Dunlop, Phoenix Turbine LLC



Doyle Fletcher, Rochem Technical Services USA Ltd; Dave Keys, Dell Power Plant; Howard Moudy, National Electric Coil; Jim Sellers, Integra Power Group

Dion Beckner, ACT Independent Turbo Services; Kevin Martinez, Trinity Turbine Technology LP; Donnie Millett, Falcon Crest Aviation Inc; Brett Crochet, Dow Chemical Co

Bill Barras, Wood Group GTS; Pete So, Calpine Corp; Bill Shama, Donaldson Company Inc; Chris Oliveri, Wood Group GTS

Getting started, 1991

The contributions of users groups to the commercial success of gas turbines cannot be overstated. These machines are relative newcomers to the power generation sector of the electric power industry and without a proactive and collaborative user community, the development of today's large, efficient, reliable, low-emissions gas turbines certainly would have taken longer than it has.

It is even conceivable that a utility industry dominated by large steam plants might never have embraced gas turbines as an alternative to coal-fired and nuclear central stations had the dedicated user "pioneers" not been so successful in helping the OEMs correct early design deficiencies.

Historical perspective. The first industrial gas turbine commissioned for electric generation, rated 3.5 MW, began operating at Oklahoma Gas & Electric Co's Belle Isle Station in June 1949—seven decades after generators driven by steam engines first produced electric power at Thomas Edison's Pearl Street Station in New York City.

For the next 15 years or so, gas turbines were pretty much viewed as a novelty by regulated electric utilities, which produced about 90% of the nation's electricity until deregulation of generation began in the 1990s. Prevailing attitudes on the value of gas turbines in an integrated electric system began to change following the Northeast Blackout in November 1965 when they helped boot-strap the grid back into operation. Until that time, gas turbines primarily were associated with non-critical peak-shaving applications.

One result of the blackout was a run on black-start units—mostly General Electric Frame 5s and Pratt & Whitney FT4s. That first market bubble lasted into the early 1970s, raising the profile of gas turbines and stimulating the development of larger machines. The design effort on GE's Frame 7 series of engines began about a year after the blackout and the first unit was installed as the 1970s dawned. The MS7001A had a 1650F firing temperature and was rated 47 MW—about three times the output of the latest-model Frame 5s offered at that time.

Design development and market acceptance of the Frame 7 product line proceeded rapidly. The nominal 75-MW 7E was introduced with a firing temperature of 1985F only 10 years later (1980). An even bigger step was taken in the ensuing decade. The first F-class machine, rated 147 MW and having a firing temperature of 2300F, shipped to Virginia Electric & Power Co's (Vepco) Chesterfield Power Station in 1988; christened Unit 7, it was declared commercial in June 1990. Sister unit Chesterfield 8 began commercial operation in 1992 (May), the year the 159-MW 7FA was introduced with a 2350F firing temperature. Design improvements in the MS7001F since then are summarized in the table.

When the 7F Users Group conducted its first meeting in November 1991, Chesterfield 7 was the only F-class machine running in the US. It had 9000 hours of operating experience. Four utilities were represented at that forum in Baltimore: Vepco, Baltimore Gas & Electric Co (BGE), Florida Power & Light Co (FPL), and Potomac Electric Power Co (Pepco). There were 14 attendees.

The meeting began with short reports by the utilities. Each had at least one gas turbine on order, with expected commercial operating dates ranging from June 1992 into the late 1990s (no specific year). Interestingly, all engines would have dual-fuel capability and only two of the nine gas turbines planned would be used in simple-cycle service.

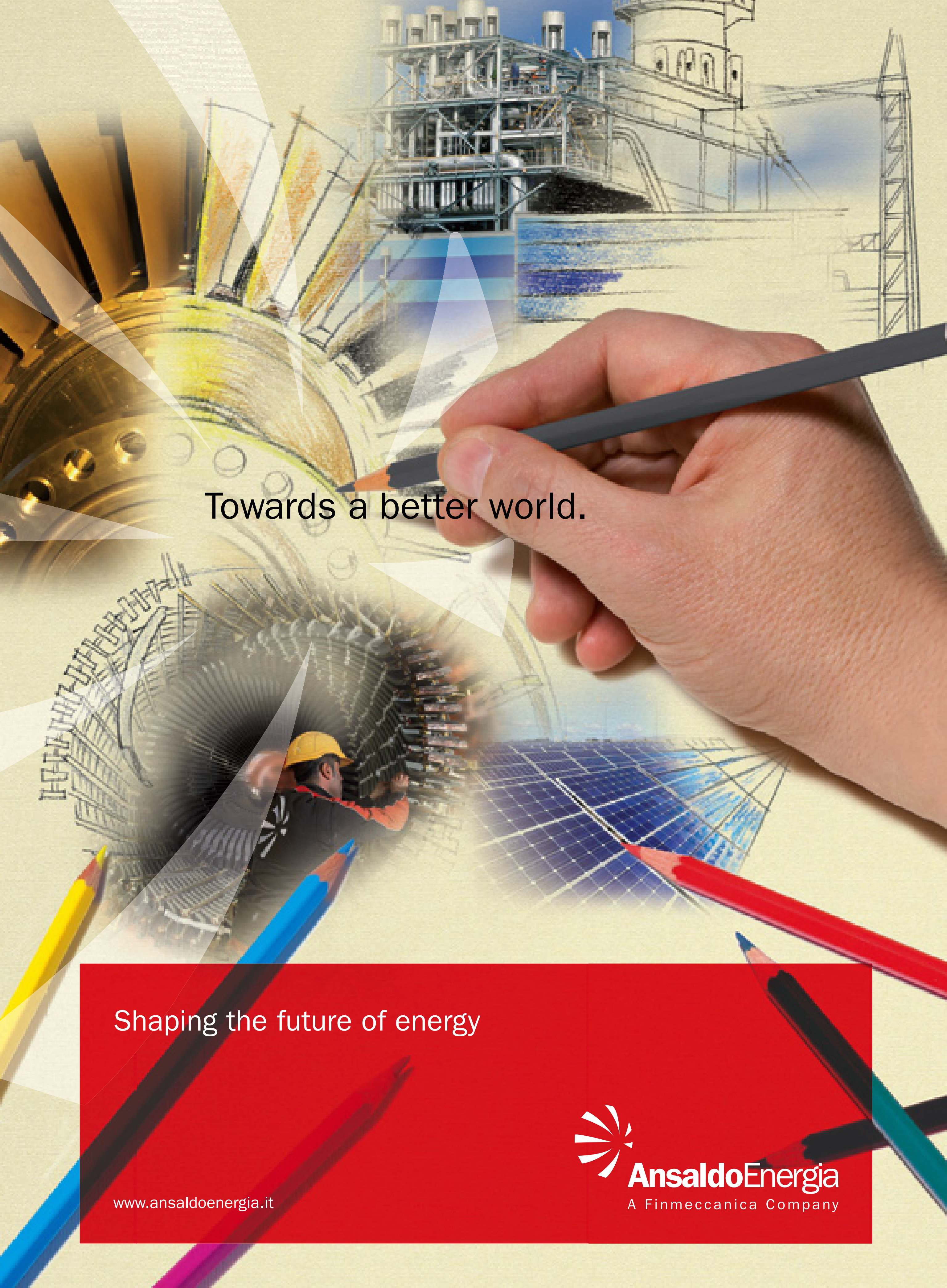
The opening status reports indicated that two of the participating utilities were repowering existing steam plants to form their combined cycles. Also that two companies were planning to install diverter dampers on their GTs to maximize operating flexibility. The first 7FA going into service would be equipped with dry, low-NO_x combustors because of emissions restrictions where that plant was to be located. Gas turbine controls would be either Mark IV or Mark V; DCS systems were from Westinghouse Electric Corp, Foxboro Co, and Honeywell Inc.

Of considerable interest to attendees was the Vepco report on Chesterfield 7's operating experience. Learning from the experiences of colleagues can save time and money, so this information was of particular value to anyone with a unit on order. For the first meeting that meant everyone in attendance.

Chesterfield 7's performance numbers were positive. For example, the equivalent availability of the prototype engine since COD was 85.79%. Two clarifying points: The unit was "out of the money" for about half of its 3500+ non-operating hours. Importantly, half the hours Chesterfield 7 was out of the money, the fuel-gas compressor was unavailable and the

Milestones in the development of the 7F gas turbine

Original model	New model	Year	Description	Firing temp, F	Pressure ratio
7191F	7F.01	1988	Prototype	2300	13.5
7211F	—	1991	First production model (same as 7191)	—	—
7221FA	7FA.01a	1993	—	2350	15
7231FA+	7FA.02	1996	—	2400	15
7241+e	—	1999	Non-Snowflake	2420	15.5
7241+e	—	2001	Snowflake	—	—
7241+e	7FA.03	2009	Enhanced compressor	—	—
—	7FA.04	2010	Advanced HGP (similar to 7FB)	—	—
—	7FA.05	2012	Advanced compressor (14 stages)	—	—
7251FB	—	2002	—	2500+	18.5


Towards a better world.
Shaping the future of energy
AnsaldoEnergia
A Finmeccanica Company
www.ansaldoenergia.it

high cost of alternative oil was the reason for it being uneconomic to operate the unit.

The speaker noted, in particular, the unit's run from the beginning of April until the end of October (1991) when Chesterfield 7 was dispatched right behind the nuclear units and ahead of all coal units—including three mine-mouth operations. The message was clear: F-class gas turbines were competitive mainstream generation assets right out of the box.

Compressor fouling and how to deal with it is a subject discussed at most user-group meetings. Vepco engineers reported no load degradation on Chesterfield 7 based on weekly performance tests. The unit was not equipped to perform online water washes and offline washes had been done only three times since COD. Interestingly, one of the utility participants had specified a coated compressor rotor for its gas turbines; the Chesterfield 7 compressor was uncoated.

Specific issues mentioned in the Vepco presentation essentially were of two types:

- Manufacturing and field errors/oversights unrelated to new technology—such as a generator rotor shipped from the factory with shorts in it and metal shavings found in the steam turbine because of an inadequate steam-line blow.
- Challenges presented by the higher gas temperatures and pressures associated with F-class technology and cycling operation, such as loss of turning vanes and cracking of vent piping in the heat-recovery steam generator (HRSG).

Engine vibration on startup and wear and tear on exhaust thermocouples were two more subjects that received meaningful discussion time. In its first year and a half of operation, Chesterfield 7 lost an average of one exhaust t/c daily; the unit has 27 thermocouples.

Fast forward to today. At the upcoming 7F conference in San Antonio, discussion sessions are almost sure to include mention of generator shorts, cracking of HRSG tubes, loss or breakage of turning vanes in the hot gas path, and thermocouple failures. While today's issues are similar to those discussed during the 1991 meeting, they really are not the same.

Over the last two decades the operating paradigm of the combined-cycle fleet has changed, the engines have gotten larger, firing temperatures hotter, emissions regulations more restrictive. Yesterday's solutions generally are not adequate for today's cycling regimen and higher gas temperatures and flows. Challenges persist and new solutions are necessary: A user group's work is never done.

The maintenance session at the first meeting reflected very orderly utility thinking on overhauls in the days before deregulation and OEM long-term service and parts agreements. It's an interesting contrast to the factors and formulas owners are governed by today. A Vepco participant noted that combustion inspections had been based on a yearly schedule and that was going to change to an 18-month interval because Chesterfield 7 was being dispatched fewer hours than originally thought.

One of the other utilities offered a firm schedule for maintenance outages based on best available information from the OEM. It called for an 8000-hr interval between combustion inspections, 24,000 hours between HGP inspections, and 48,000 hours between majors. The speaker noted that the company had developed a schedule that predicted parts replacements and refurbishments for 30 years. Recent meeting have reflected dramatically different maintenance schedules.

Here's what was the1991 thinking on combustion inspections: A five-day outage would be sufficient with new spares on hand for immediate replacement. If reconditioning of parts was necessary, extend the outage by two weeks. A typical CI at Chesterfield 7 called for up to eight persons per shift—six working on the combustors, the others handling miscellaneous work items.

Learning on the job. Cracking of nozzle tips at around 4000-5000 hours was one of the early problems at the first Frame 7 plant, thereby preventing Chesterfield 7 from achieving its desired CI interval. One of the first lessons learned was that all fuel nozzles are not created equal. Station personnel did not realize the OEM balanced the entire set of 84 nozzles to optimize machine performance until they swapped out cracked nozzles with new ones and experienced higher exhaust spreads.

Unit operation. Vepco shared with the group its startup procedure, which took about an hour when the gas turbine was cold: Fire the GT, synchronize at 10 MW, match boiler steam and turbine metal temperatures prior to rolling the steamer. Gas-turbine ramp rate was 8 MW/min.

Transferring from gas to oil at full load was no problem, the representative said. It took about two and a half minutes to complete. However, switching from oil to gas was more difficult and required up to about twice as long for a successful transfer than going from gas to oil. Speaker said the gremlin probably would be found in the regulator in the gas main—possibly the valve was too small or its response time too slow. On a gas-compressor trip, the unit flamed out before the transfer to oil could be completed.

"Comparing notes" is a big benefit of user-group participation. One participant began talking about the two atomizing-air coolers provided with his package for redundancy. Someone else said GE had eliminated the second cooler in their package. Interesting, because there really did not appear to be sufficient operating experience to support such a decision.

Why not err on the conservative side so early in the lifetime of F-class units? First participant jumped back into the conversation noting that the OEM had not run separate drains off the coolers and cautioned against linked drains. Ganging of drains is well known for causing major issues on HRSGs.

Thermal shock in steam-turbine bypass lines was recognized as a potential problem at the dawn of F-class units. One utility avoided the possibility of this occurring by maintaining steam flow through the bypass at all times.

Sharing is a big part of the user-group value proposition. Every plant needs procedures—startup, operations, and maintenance. The three utilities that soon would be starting up their first F-class units acknowledged a desire to work collaboratively in the development of procedures not yet available. An action item taken was for each of these companies to develop a list of procedures available together with a list of those still required and by when.

Staffing and personnel development and training generated significant discussion as you might imagine. It takes years of experience with a new engine model to right-size your staff. Today, most 7FA owner/operators are running plants with two-dozen or fewer permanent personnel and would chuckle at the thinking in 1991—before deregulation, as noted earlier.

One of the utilities had six people on a shift for two 1 × 1 combined cycles; another planned to have four per shift (2 × 1 arrangement) and was considering a maintenance staff of 40 to 45. A utility planning two 2 × 1s focused on five operations shifts of four people for each unit and 40 to 45 total staff for the first combined cycle and an additional 15 to 25 when the second unit was completed.

Closely related to the then-and-now staffing comparison is personnel training. During a discussion on that topic one participant noted that his company had a training program for operators that ran 39 months. That was typical for regulated electric utilities back then. At user-group meetings in the deregulated era you often hear considerable angst over the retirement of senior personnel and the lack of suitable candidates to fill open positions.

One reason for the shortage of qualified operators, electricians, instrument techs, mechanics, etc, is that small independent power producers don't have the financial resources or the time—and in some cases, the inclination—it takes to develop personnel qualified to operate and maintain today's high-tech turbines. It is not unusual for some investors to flip their generation assets in less time than it would take to train a qualified staff.

As the first 7F Users Group meeting closed, it's reasonable to assume no one in the room could have imagined that 20 years later:

- The organization would still be in existence and that its annual conference and exhibition would have grown to become the world's largest venue for F-class technology and business discussions.
- Two of the four utilities represented at the meeting would no longer be in the business of electric generation.
- Unregulated generating companies, which did not exist in 1991, would control 42% of the nation's power-production capability and 57% of all gas-turbine-based generation.
- One of the 1991 attendees would participate in the 20th anniversary meeting and two participants would be serving on the steering committees of other gas-turbine user organizations. Continuity of technical leadership is vital to progress. That's service user groups like the 7F provide the electric power industry at no cost. CCJ

Implement recommendations in 1509-R3, 1638, 1795 to reduce operational risks

Technical Information Letters (TILs), published periodically by GE Energy, offer recommendations to resolve equipment issues, improve gas-turbine O&M and reliability, and protect the health and safety of plant personnel. They should not be ignored or set aside for future consideration. Unfortunately, TILs do not always filter down to responsible personnel on the deck plates; and even when they do, operators sometimes find the language confusing. Either way, the message may not get through to where it's needed.

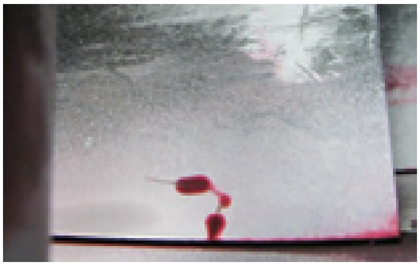
Perhaps no one sees the breakdown in communication as clearly as the field service personnel at Advanced Turbine Support Inspections LLC (ATS), Gainesville, Fla, who follow TIL requirements to the letter when making their periodic borescope inspections. The need for a better understanding of gas-turbine (GT) technical issues by the O&M staffs at plants powered by 7FAs prompted the development of a webinar focusing on the importance of TILs 1509-R3, 1638, and 1795 to owner/operators. The webinar, which aired December 14, provided the content for this report.

You may recognize some of the issues identified from previous articles, such as S0 vane cracks in "Keep up with OEM advisories," which appeared in the 2011 Outage Handbook (access at www.ccj-online.com). But those articles typically focused on one or two specific concerns introduced in discussion sessions at user group meetings. This report summarizes the advisories of greatest importance to most 7FA owner/operators in one place, presents industry-wide inspection findings, and offers some suggestions from the inspection team based on field experience.

Mike Hoogsteden, Dustin Irlbeck, and Rod Shidler of ATS developed the material presented by Hoogsteden and Irlbeck on the webinar, CCJ ON*screen's* Scott Schwieger coordinated and produced the event, and Engineering Manager Greg Snyder represented sponsor Dresser-Rand LETT (sidebar).

1509-R3 highlights

- R0 leading-edge distress can be caused by impact damage, root-area erosion by fogging, and/or the introduction of corrosive elements into the compressor inlet. Cracks left unattended can grow to 1.5 to 3 in. before blade liberation and significant collateral damage. The TIL recommends annual visual inspection. If any R0 root cracks are identified, inspect all R0 roots immediately. ATS believes that the TIL doesn't go far enough and has the potential to miss small or tight indications that could result in blade liberations and a catastrophic compressor event.



1. Radial tip crack on R1 blade identified with visible dye penetrant

2. Trailing-edge platform crack on S0 vane identified with visible dye penetrant

- R0 and R1 blade-tip distress is caused most commonly by tip rubs against the case during operation. This usually is identified by tip discoloration or a heat-affected zone (HAZ) or by rolled metal. Such distress can lead to radial tip cracks (Fig 1) and tip liberations with significant collateral damage to forward and aft compressor stages. If tip discoloration is identified, the TIL recommends dye penetrant inspection at 25, 50, and 100 actual fired starts from the discovery of the rub. If rolled metal or tip loss is identified, repairs should be completed at the first opportunity. Until then, dye pen inspections should be performed every 12 actual fired starts. After repairs, inspect at 25, 50, and 100 actual fired starts. ATS has identified multiple rotor-blade cracks with visible dye penetrant that were not seen during conventional visual inspections.
- S0 stator-vane trailing-edge cracks apparently are caused by vane "lock up" (Fig 2). Cracks could result in vane liberation and significant collateral damage to forward and aft compressor stages. If trailing-edge cracks are found, replace the affected vanes immediately. Note that ATS has identified S0 trailing-edge cracks with an eddy-current inspection that were too small to find visually and with fluorescent dye. Further, ATS has identified S0 leading-edge and radial tip cracks in both flared and unflared compressors; they are not addressed in 1509-R3.

To sum up, in the last 10 years ATS has completed more than 1000 in-situ inspections and identified over 150 cracked rotor blades, more than 60 S0 cracked vanes, and two S1 cracked vanes. For rotor blades and stator vanes that do not show any signs of distress, ATS recommends the following as a minimum: Annual visible dye-pen inspection of R0/R1 blades. Plus, dye-pen or eddy-current inspections of S0 vanes annually or after each 100 actual fired starts. Subsequent inspections based on the results of the inspections would run parallel to the OEM's recommendations.

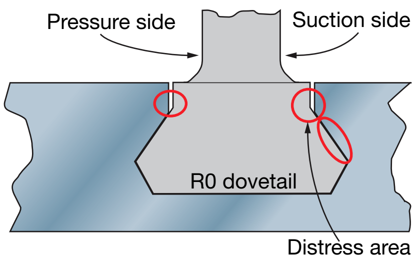
1638 highlights

TIL 1638 addresses F-class R0 in-situ and R1 case-off ultrasonic inspections (UT) for dovetail distress below the blade platform. The testing interval is to be 8000 fired hours or 150 fired starts, whichever occurs first. This recommendation is modified for peaking units performing more than 150 annual starts to just before and following the peak season. The TIL applies to all Frame 7 and Frame 9 F-class turbines installed with non-undercut R0 blades (which includes the baseline standard R0 and P-cut R0 designs).

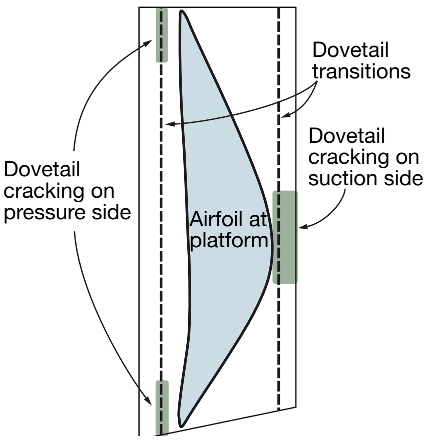
The distress area generally is in the center fillet region on the suction side of the rotor blade. Additional distress areas identified during ATS inspection are the entire sloped face in the center fillet region on the suction side and both the leading- and trailing-edge regions on the pressure side (Figs 3 and 4). Here's a rundown on ATS inspection results to date:

- Standard R0 blade suction-side fillet region: 41 cracked blades. Damage found at from 1600 to 58,000 fired hours and from 30 to 2700 starts.
- Standard R0 blade suction-side slope region: three cracked blades. Damage found at from 7600 to 33,700 fired hours and from 659 to 2059 starts.
- Standard R0 blade pressure-side fillet region: one cracked blade at leading edge, one at trailing edge. Damage found at from 7300 to 21,700 fired hours and from 888 to 1482 starts.
- R1 blade suction-side fillet region: two cracked blades (both in-situ). Damage found at from 9100 to 44,000 fired hours and from 255 to 655 starts.

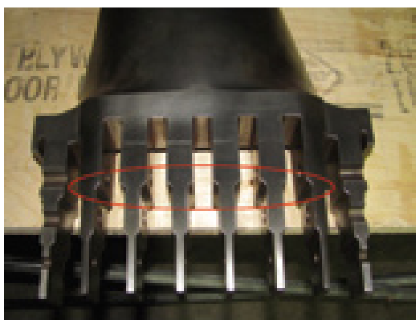
To sum up, ATS has to date identified 116 dovetail cracks with no false calls. It also has found R0 dovetail cracks which are outside of the interest areas and coverage capabilities of other inspection agencies. Finally, the company's inspection team has identified R1 dovetail cracks in-situ which ranged from about 1 to 3 in. long and from depths of 0.255 to over 1 in. The cracks in this last unit likely would have propagated to failure before the next scheduled case-off accessibility.



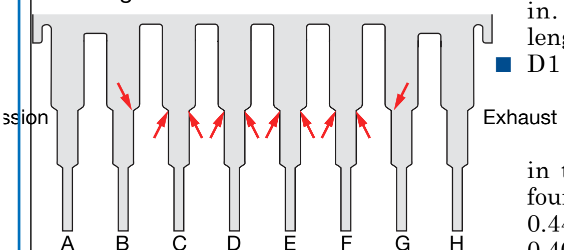
3. Distress areas identified during ATS inspections (side elevation view)



4. Distress areas identified during ATS inspections (plan view)



5. Cracks in 40-in. titanium L-0 buckets typically are located in the transition fillet from the top portion of the finger to the center



6. Primary indication areas identified during ATS inspections are the inboard transitions on B and G fingers and the admission and exhaust transitions on the C through F fingers

ATS recommends performing ultrasonic inspections of the R0 and R1 platform areas before and after each peak operational season and not exceeding a six-month interval. Subsequent inspections are based on the results of the inspections and would run parallel to the OEM's recommendations.

1795 highlights

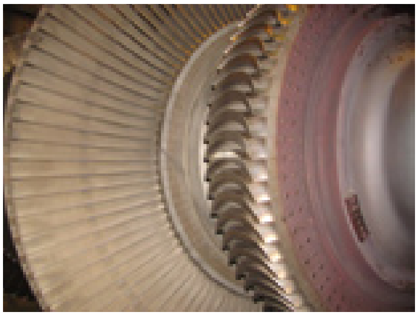
TIL 1795 pertains to L-0 40-in. titanium bucket inspections on steam turbines found in some F-class combined-cycle plants. It was issued in response to cracking identified in dovetail fingers of some buckets. Cracks typically are found in the transition fillet from the top portion of the finger to the center (Figs 5 and 6). At least one instance of bucket liberation has been reported (in Korea). Here are the OEM's suggestions:

- Remove the last-stage buckets and perform a fluorescent penetrant inspection (FPI).
- Evaluate for inspection applicability units operating above 650 start/stop cycles, or those planning to run above 650 cycles prior to bucket modification.
- TIL should remain in effect until the L-0 buckets have been replaced with hardware of new design.

TIL 1795 is time-consuming to perform. Estimate four weeks just for conducting the inspection (breaker to breaker) if you're going to use the OEM's plan. Add another three weeks to modify the buckets as well. Alternatively, you can opt for ATS's recently announced in-situ inspection technique, which requires one 12-hr shift per row with minimal unit downtime and preparation. Note that removal of the LP turbine hood, rotor, and buckets is required to conduct an FPI inspection.

Findings to date include the following:

- D11 steamer with about 1600 start/stop cycles. All L-0 buckets were inspected; all had cracks ranging in depth from 0.1 to 0.193 in. and from 0.064 to 0.531 in length.
- D11 steamer with about 1400 start/stop cycles. Inspected 41 of the 152 L-0 buckets (76 for each of the two L-0 wheels in the two-flow LP section) and found cracks in each ranging from 0.44 to 0.179 in. deep and 0.073 to 0.407 in. long.
- A10/D11 steam turbines with fewer than 1200 start/stop cycles. Ten L-0 rows were inspected in-situ with no recordable indications.



7. Buckets were machined off L-0 row to return steam turbine to operation until replacements could be found to replace the row where finger cracks were identified

ATS recommends performing in-situ inspections of the L-0 last-stage bucket dovetails yearly.

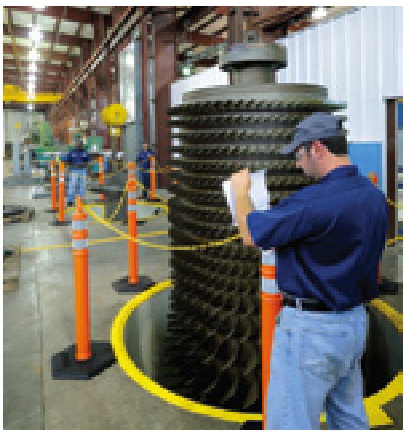
End notes:

- In cases where many buckets are affected and spares are not readily available, an alternative to replacement is to machine off the L-0 buckets at the wheel OD and return the rotor to service (Fig 7). Output is reduced, of course—perhaps by 25 MW per wheel modified in this manner.
- For buckets having no indications, the holes for the retaining pins are reamed and oversize pins are used to reattach the airfoils to the wheel. CCJ

Preparing for shop inspection, refurbishment of GT rotors

Greg Snyder, engineering manager, Dresser-Rand LETT, is an expert on rotor inspection, refurbishment, and life extension. Rotors are a hot topic among owners and operators today because many are approaching the number of fired hours or starts where teardowns for inspection of component parts are required. Most O&M personnel at F-class plants have never been party to a rotor disassembly and inspection and it was Snyder's intent to provide some perspective on the process to help them understand what would be done, and why, and how.

He began by explaining the capabilities the shop you select should have in order to do the proper job.



A. When conducting due diligence of candidate shops to handle your rotor inspection and refurbishment be sure to evaluate the equipment and fixtures each has dedicated to the effort

Due diligence includes surveying the dedicated equipment and fixtures needed to disassemble and reassemble the rotor (Fig A); reviewing procedures and the resumes of personnel who will be assigned to your job, and evaluating the level of engineering support available.

Snyder then spent a couple of minutes familiarizing webinar participants on the terminology used. This made plant people aware that shop people speak a different "language" and that some home study would be required before a shop visit (Fig B).

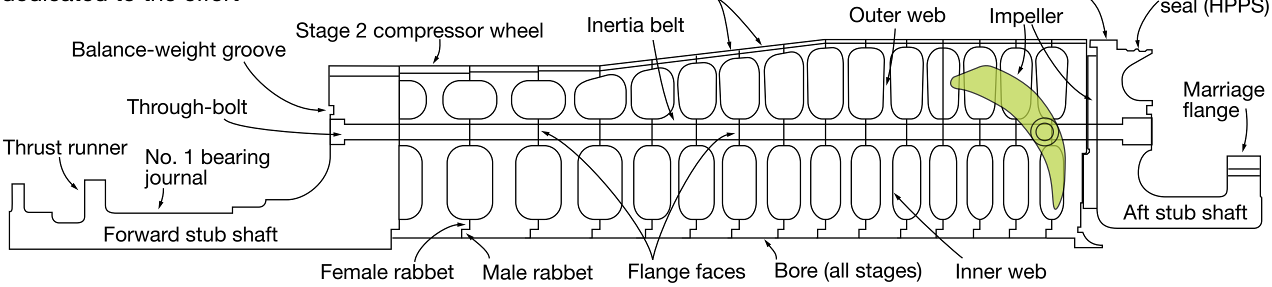
Next came the realization of how straight straight really is in the world of rotors. You may have heard that when fully assembled and put to the test on a balance machine the permissible run-out for the rotor might be one or two mils and not given it much thought.

Once in the shop you will be in awe of the craftsmanship involved in achieving such numbers and what they really mean (Fig C). Snyder put them in perspective: 1 mil (one thousandth of an inch) is approximately one-third the diameter of a human hair. Turning a 50-ton rotor 1 mil off center and rotating it at 3600 rpm places an additional 37,000 pounds of force on the bearings.

Of course you want to know what happens if your rotor is assembled and doesn't meet OEM run-out specs. The answer is simple: You tear down the rotor again, figure out what you did wrong, and re-assemble. The rotor doesn't leave the shop until run-out specs are satisfied. Rotor work is the work of professionals with sophisticated procedures, computer programs, and tooling (Fig D). Snyder finished up with a review of how parts are inspected, refurbished, and reassembled.

C. The shop effort includes dimensional checks and nondestructive examination, checking of journals, restoration of rabbet fits, recoating, reblading, etc

D. Balancing and run-out checks are final steps in the rotor overhaul process



B. Understand shop lingo before visiting. Terminology can differ among OEMs

Get a grip on stator core, rotating-field damage mechanisms

Generator stator cores are deceptively simple devices. But there's a lot that can go wrong with the 10 acres of insulated surface in a typical 200-MW unit. Rotating fields present their set of problems, some of which have led to catastrophic failures

Clyde V Maughan, Maughan Generator Consultants

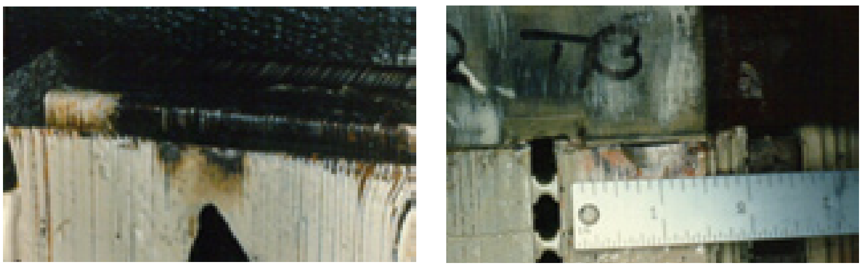
Yes, you read that right. The typical core for a power plant generator has 50,000 to 200,000 steel laminations, each 14 or 16 mils thick and insulated on both sides. The total area of the laminations may amount to 400,000 ft^2, or roughly 10 acres of surface, for a 200-MW unit.

Local core damage is conducive to local electrical shorts. Those between two or three adjacent laminations are tolerable, but extended shorting can result in a core meltdown and an outage of six months or longer costing $10-million or more.

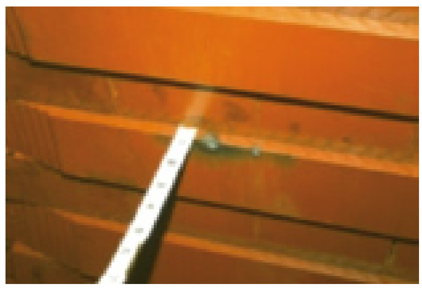
Generator cores are sensitive to several deterioration mechanisms initiated mostly by mechanical impact damage. In addition, if core clamping pressure is insufficient locally or generally, lamination vibration can occur, causing wearing of the insulation and breakage of laminations. While these mechanisms are known, they aren't necessarily well understood. This article, one of several by the author to appear in the **CCJ**, on generator damage and repair, reviews damage mechanisms and corrective actions (Sidebar).

Failure modes

Core deterioration ranges from minor localized overheating to complete core meltdown. The overheating in Fig 1 probably resulted from the impact of a tool during maintenance. Damage appears relatively benign, even though shorting of laminations is clearly indicated. This type of damage can be safely removed through careful grinding by skilled workers (Fig 2).



1, 2. Local core overheating was caused by damage to the insulation of a few laminations (left). Section of damaged laminations was safely removed by careful grinding (right)



3. Local overheating, most probably caused by failure of lamination insulation, is of greater concern than damage in Figs 1, 2

The condition observed in Fig 3 also is minor but reveals more pronounced local overheating. A qualified generator expert should assess whether this condition can be

Maughan on generators

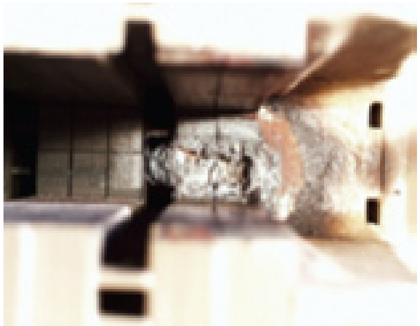
This is the seventh article in a continuing series on generator monitoring, inspection, diagnostics, and root-cause failure analysis developed by Clyde V Maughan, president of Schenectady-based Maughan Generator Consultants, for the **CCJ**.

The articles listed below, available at www.ccj-online.com/maughan/, are a valuable resource for owner/operators of turbine-driven generators:

- Maintaining carbon-brush collectors, 1Q/2010.
- Options for monitoring generator condition and their limitations, 2Q/2010.
- Input from monitoring, inspections, tests critical for maintenance planning, 3Q/2010.
- Generator condition monitor critical to avoiding catastrophic loss, 1Q/2010.
- Root-cause diagnostics of generator service failures, 2011 Outage Handbook.
- Don't fall victim to these precursors of generator failure, 2Q/2011
- Get a grip on stator core, rotating-field damage mechanisms, 3Q/2011

4. Severe melting caused failure of the entire tooth

5. Total meltdown dictated replacement of the entire core



6, 7. Slight discoloration of iron was considered minor (left), but melting at that spot after a few hours of operation with a new winding (right) proved that diagnosis incorrect

8. Core melting caused by over-fluxing is very severe

repaired with grinding, removal of burrs by acid etching, and periodic insertion of mica flakes.

Melting of laminations in Fig 4 is severe, but confined to the top half of a tooth at the end of the core. Ground relaying in all likelihood would have tripped the unit, preventing more widespread meltdown. Most damage of this type requires full stator rewind and restacking of the end of the core at minimum. In this particular case, though the repair is unlikely to be accepted by a design engineer, a temporary repair of machining out the melted and overheated iron and replacing the missing tooth iron with a glass block, proved successful.

Widespread meltdown of several tons of iron is shown in Fig 5. In this case, the only option was to replace the entire core, along with a full stator rewind, field rewind to remove the heavily contaminated insulation, and extensive cleaning of the frame and coolers.

The condition shown in Fig 6 was considered minor and of no concern. Three hours of operation after a new winding was installed, the stator ground relay tripped the unit; subsequent inspection revealed continued and rapid deterioration (Fig 7). This incident was quite unfortunate, because an EICid (Electromagnetic Core Imperfection Detector) test revealed nothing for concern. But the test was almost certainly conducted improperly. Lamination shorts severe enough to turn the iron blue would have shown up clearly if the test were done correctly.

Hopefully, the discussion thus far shows that determining the severity and corrective actions for core damage is not for amateurs.

Over-fluxing of the core is rare, but can cause exceptional damage (Fig 8). It only occurs offline. If the offline field current goes significantly above that required to obtain rated voltage on the open-circuited stator winding, high leakage flux will go beyond the outside diameter of the core. The building bolts, or key bars, then behave like the winding of an induction motor's rotor, carrying high current which, as it traverses 180 deg around the end of the core, will burn the core's ends. If the current reaches the maximum output of the excitation system, burning can be fatal to the unit in moments.

Core looseness

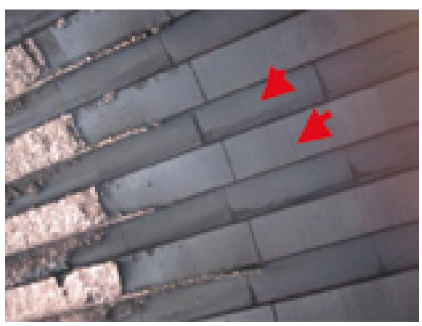
Long cores may have up to 5 in. of additional insulation thickness. Creep of this non-steel material can lead to gradual loosening over time. A core may need to be retightened every 15 or 20 years.

A separate loosening issue common to all cores results from crowning in the laminations. The laminations are punched from rolled steel, and have a very slight crown at the center of the roll—and, therefore, the lamination. This causes the core to be slightly loose at the tooth tip and at the outer radius. Outer-radius looseness isn't an issue but the tooth-tip looseness is; it can allow vibration of the lamination and wear of its insulation. As the condition gets worse, the laminations may begin to flutter and fatigue the iron, causing the corners to break off.

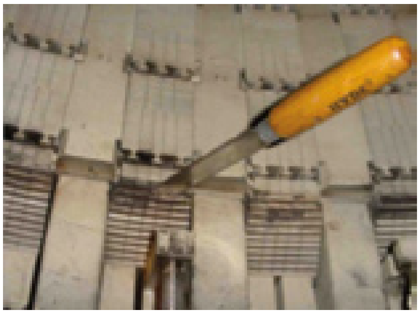
Loose pieces of core lamination can be held by magnetic force to the outside surface of the stator bars adjacent to the end of the core. Vibrating pieces then wear through the stator bar groundwall insulation (Fig 9). You can correct tooth-tip looseness by placing a ring of tapered inserts in the teeth around the full core circumference, about every 20 in. along the core length (Fig 10).

Annealing processes used in some designs exacerbate core problems. If the individual annealed laminations exhibit a slight wave (that is, do not lie exactly flat), it creates a minor wave around the core's circumference, causing teeth to loosen at the ends of the core (Fig 11). It is possible

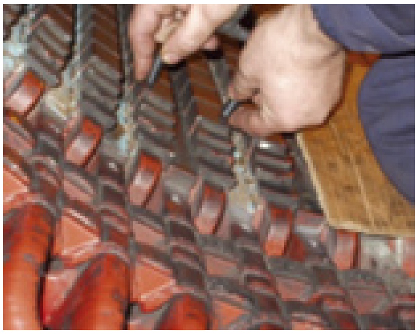
9. Stator-bar insulation damage was caused by lamination looseness



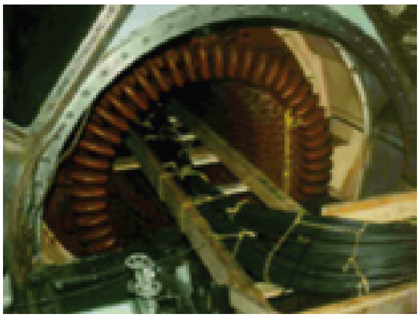
10. Tapered inserts correct tooth tip looseness



11. Ability to insert a knife into the core confirms loose tooth iron



12. Step iron at the end of the core is tested manually



13. Heavy excitation coil is required for a high-flux test

to tighten local loose areas by inserting tapered material into the loose teeth or retightening the core itself. However, if the lamination insulation is worn or deteriorated, the tightened core is vulnerable to shorting, melting of iron, and, in the worst case, a fatal condition.

Lamination insulation deteriorates naturally, space between laminations is created locally because of looseness, and/or laminations may become damaged by foreign objects. At every convenient opportunity, you should evaluate the integrity of the insulation by the relatively simple EICid test (Fig 12), keeping in mind that this is a screening test. Where EICid readings are of concern, follow up with the more extensive high flux loop (ring) test (Fig 13), which requires heavy cable, high power, and a large breaker, and is potentially more hazardous to equipment and personnel.

Rotating fields

Both stators and fields can deteriorate in many ways. In almost all cases, the failure is electrical in nature but the root cause is usually mechanical.

Contamination occurs from moisture and solids—including ambient dust, wear products from vibrating material, and products of combustion during an electrical arc failure in the stator (Fig 14). A high moisture environment can severely rust a field, such as the magnetic retaining ring and field body forging (Fig 15). Usually, general contamination can be managed by thorough cleaning, but in extreme cases, rewind is likely. Severe rusting produces conductive material which contaminates the electrical creepage surfaces, and a full field rewind will probably be recommended.

Winding distortion. Turn and coil distortion result in shorts that increase excitation current. Turn shorts concentrated on the smaller coils result in a thermal bow of the field forging. Result is an increase in field vibration. In sufficient numbers, turn shorts force a shutdown for corrective action.

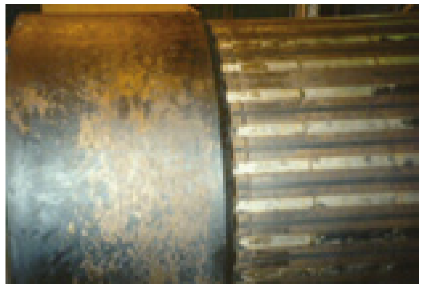
Shorted coils are far more serious. They greatly increase excitation current, but the associated arc at the short also may burn the forging at that location.

In a severe example of turn distortion (Fig 16), the two top turns of the smallest coil probably shorted together. High friction between the top turn and the retaining ring insulation, and high copper temperature on the top turn, probably combined to cause distortion. The severe turn/coil distortion in Fig 17 would have resulted from very high over-temperature of the field winding.

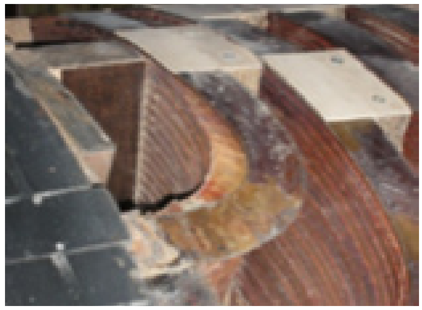
Widespread, less dramatic turn and coil distortion, though just as nettlesome (Fig 18), can result from a combination of high temperature, high mechanical forces, uneven or high coefficients of friction, and the inherently poor mechanical properties of copper (which fall off rapidly as temperature increases above 265F). Assistance from the OEM probably will be required to determine root cause and corrective actions.

Turn fracture is less common that distortion. When it occurs, current is not interrupted but flows as in a welding arc. No alarm goes off in the control room until the field ground relay picks up. Trip then occurs but the field current will take roughly 10 sec to decay enough for the arc to be extinguished. In this

14. Field is heavily contaminated with conductive dusts

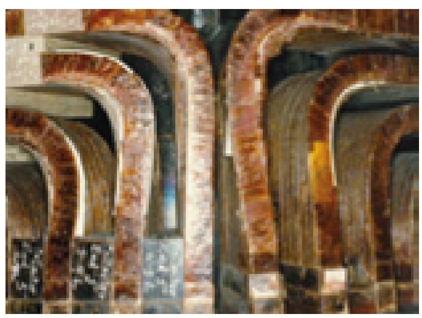


15. Rust condition can damage forgings. Resulting conductive materials can contaminate the extensive electrical creepage surfaces

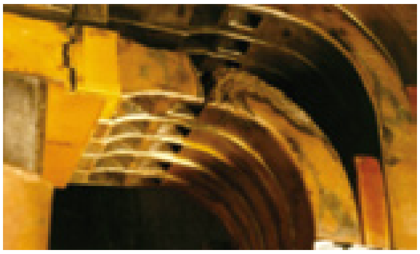


16. Top turn of the smallest coil is distorted

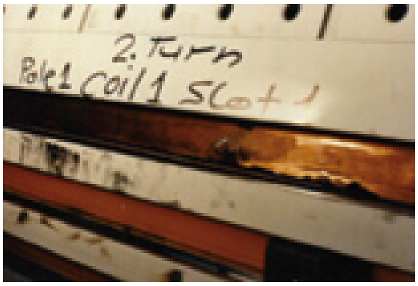
17. Severe distortion of top turns on several coils is in evidence



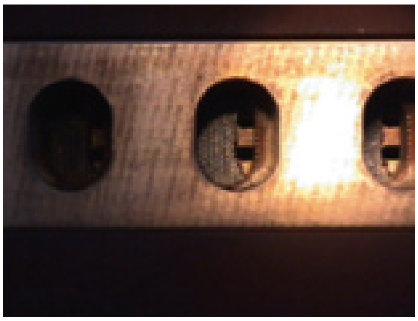
18. Coil/turn distortion shown here is serious and widespread



19. Top turn in field winding is broken



20. Burning between winding and forging occurs because field current continues to flow after a turn break



21. Turn insulation can move and block most of the discharge area

22. Broken coil-to-coil connection produced limited arc damage

23. Top-to-top connection will lose flexibility if excessive braze material is applied

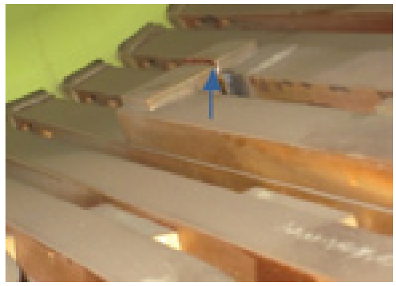
short time, extensive forging damage may have occurred (Figs 19 and 20).

Ventilation issues crop up if there is severe contamination in the rotating field or, more commonly, if the cooling-gas radial discharge holes become misaligned. The latter occurs from a combination of migration of turns/coils, migration of the insulation, and/or elongation/contraction of the copper (Fig 21). Overheating occurs when discharge holes are blocked, but more importantly, it leads to field forging bowing (as a bimetallic strip will bow when heated). At some point, the unit has to be shut down. Sometimes removing a retaining ring to allow realigning of the migrated components will fix the problem but usually a partial or full rewind will be necessary.

Connections, coil-to-coil and pole-to-pole, regardless of design, tend to be troublesome and prone to fracture. The broken coil-to-coil connection in Fig 22 fortunately did not lead to extensive arc damage.

Pole-to-pole connection breaks are more common. On two-pole fields, two jumpers act in parallel and it is common for both to fracture, such as the top-to-top connection of Fig 23. These connections are supposed to be flexible but if there is excessive braze material, the connection will lose flexibility. Fig 24 shows a pole-to-pole connection at the bottom of windings with an even number of coils where the jumper has fractured.

Access to top connections is good after removal of the connection end retaining ring. Access to bottom coil connections is limited. In a few cases, the connection was repaired without field removal from the stator. More typically, field removal from the stator is necessary, as well as removal of the two largest coils, to make a suitable repair.



24. Pole-to-pole connection at the bottom of the coils is fractured (arrow)

Field forging issues

Both the generator body and the retaining rings are highly stressed components. Mechanical damage of any type is cause for concern and immediate investigation.

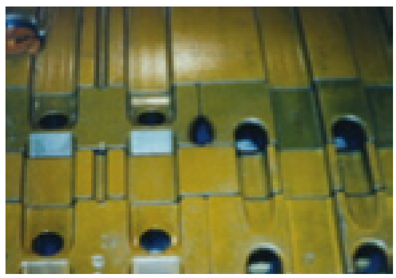
Field body cracks, when they occur, usually are located in the tooth area under the retaining ring shrink fit. They result from low-cycle fatigue related to starting and stopping of the unit. At rest, the compressive forces of the ring on the tooth area are very high. At rated speed, the stress is greatly reduced as the ring takes the centrifugal load of the mass of the ring itself and the weight of the copper coils and blocking.

Cracks also have been found at the body axial centerline on some fields, but these cracks are confined to a few machines. Recently, there was one instance of shaft cracking at the location of the inboard radial studs for the excitation current.

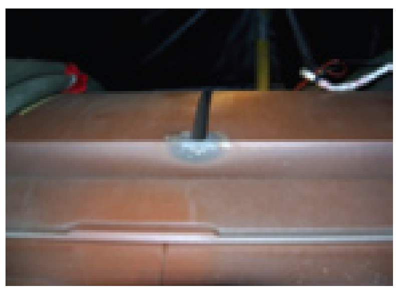
The consequences of field forging cracks can be extreme, even if their occurrence is uncommon. You must follow OEM recommendations for nondestructive examination (NDE) and possible corrective actions.

Negative-sequence currents occur when unbalanced stator current flows in the three phases or during asynchronous operation. The latter happens when the field is not synchronized to the system—for example, when a breaker closure is at standstill, during a mis-synchronizing event, or when power is being generated without field excitation current. Depending on the magnitude and frequency of the body current, the impact can range from minor burning of wedge ends (Fig 25) to highly destructive.

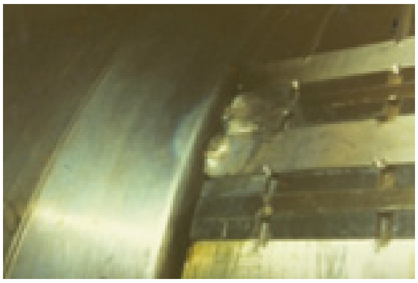
The condition



25. Burning at ends of wedges is minor, and probably benign, but a thorough investigation is advisable



26. Serious overheating of the field forging at cross slots requires grinding out of the heat-affected steel



27. Gross overheating is in evidence where the wedges and retaining ring meet

28. Extreme overheating of field forging during a negative-sequence field current event makes this component scrap

29. Retaining ring's inside surface was burned because of a short between the two largest coils

illustrated in Fig 26, for example, would require at a minimum grinding out of the heat-affected steel. Depending on the amount of material removed and the mechanical design of the unit, the field may still need to be scrapped.

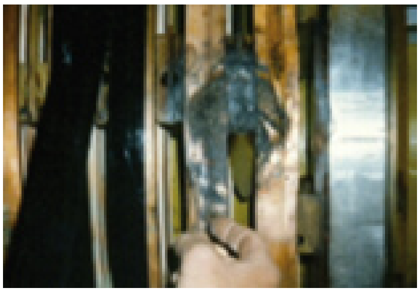
The retaining ring in Fig 27 is not shrunk onto the field body, and the wedges are not intended to be contacting the retaining ring. But the wedges have shifted to contact the ring. When high body currently flowed, severe heat damage occurred. Replacement of the ring and burned wedges is necessary in the optimistic case. The irrepairable field forging in Fig 28 was damaged by overheating during a negative-sequence current event.

The forging damage of the retaining ring shown in Fig 29 was caused by a single ground from the shorting of the two largest coils (Fig 30) and cannot be repaired. On the other hand, excitation current damage to the field forging tooth, caused by a double field-winding ground (Fig 31) can be repaired with minor grinding to remove the heat-affected steel because the burn occurred at a point with low mechanical stress.

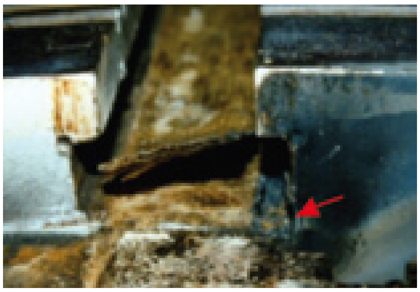
Retaining rings. Of the two common types of non-magnetic retaining-ring materials used, 18/5 and 18/18 (manganese/chromium, Mn/Cr), the former is subject to stress corrosion cracking. The 18/5 retaining ring in Figs 32-33 was exposed to raw water, it failed in service 18 months after the ring had been removed and found to be acceptable based on NDE assessment.

The industry began shifting to the 18/18 material around 25 years ago, but because of high cost and long procurement cycles, plenty of rings with the older material are still in service. If that applies to your unit, you need to keep the humidity of the internal atmosphere low, eliminate cooler leaks immediately, and consider adding a cooling-gas drier. Both 18/5 and 18/18 retaining rings need to be tested and inspected on a regular basis because the threat of catastrophic failure is high.

And finally, fear can be an excellent motivator. Consider a salient pole field (Figs 34 and 35) located in a new combined-cycle cogeneration plant. A series of ¾ in. bolts held the coil spaces on the four-pole, 1800-rpm field. One bolt fractured and the rest of the bolts at that location failed sequentially. As a result, the destruction of the generator also destroyed the connected steam turbine and the entire $60-million powerplant. CCJ

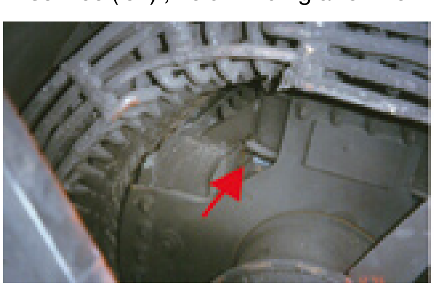


30. Short-circuit location is between the two largest coils on a field winding



31. Double field-winding ground damaged field forging tooth

32, 33. Fractured 18/5 retaining ring failed after exposure to raw water while in service (left) ; field winding after the ring failure is at right

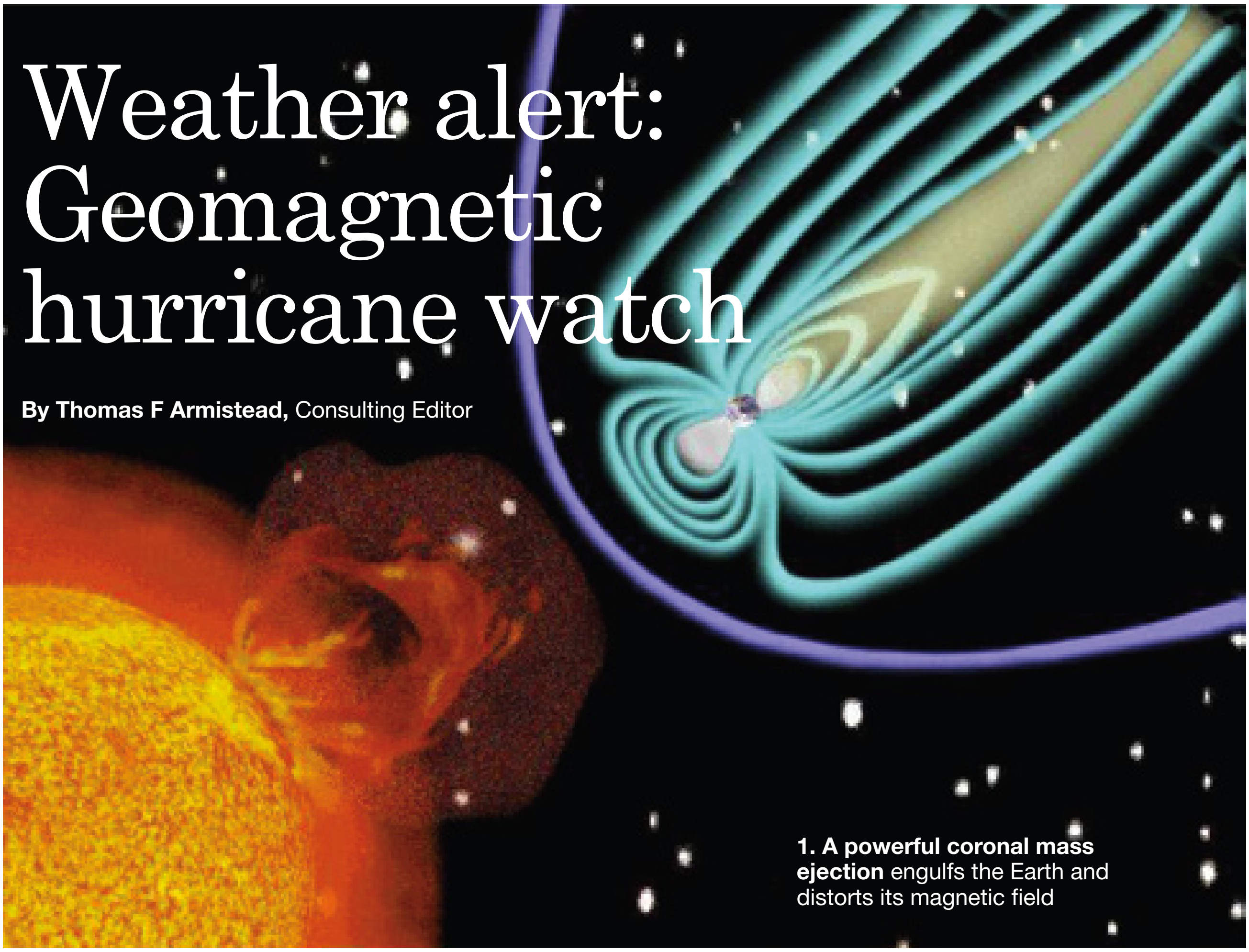


34, 35. Failure of a single bolt initiated the cascading failure of the remaining bolts for this salient pole field

Clyde V Maughan is president of Maughan Generator Consultants, Schenectady, NY. He has more than 60 years of experience in the design, manufacture, inspection, failure root-cause diagnostics, and repair of generators rated up to 1400 MW from the leading suppliers in the US, Europe, and Japan. Maughan has been in private practice for the last 26 years. He spent the first 36 years of his professional career with General Electric Co.

Weather alert: Geomagnetic hurricane watch

By Thomas F Armistead, Consulting Editor



1. A powerful coronal mass ejection engulfs the Earth and distorts its magnetic field

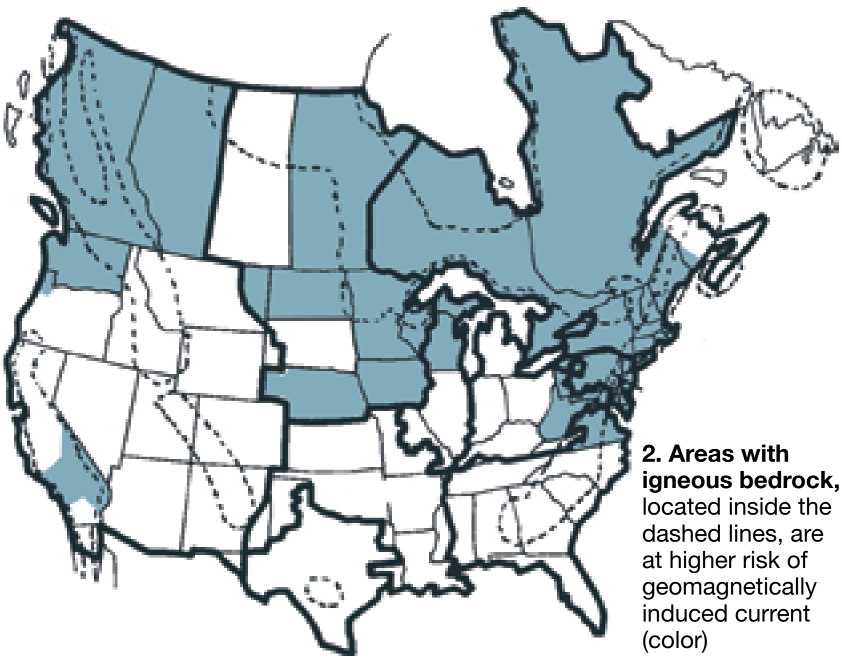
Here comes the sun, and your plant is in its crosshairs. The solar energy that sustains life on this planet cycles through pulses of activity roughly every 11 years. The pulses are evident in a crescendo of sunspots, flares, and other eruptions as the orb builds toward what astronomers call the solar maximum, then the eruptions wane, returning in another dozen years or so.

When one of the eruptions is aimed directly at Earth, the results can be catastrophic. Now the National Oceanic and Atmospheric Administration is warning the electric-power industry to prepare for unexpected events, because the next solar maximum is forecast to peak between 2012 and 2014.

How bad could it be? On Mar 9, 1989, the Kitt Peak National Observatory on the Tohono O'odham Reservation in Arizona reported a powerful flare on the sun. The next day, an explosion on the sun ejected a cloud of electrically charged particles 36 times as large as Earth directly toward our home planet. The cloud arrived at 2:44 a.m. (Eastern time), March 13.

The wave of electrons and protons washed over and around Earth's magnetic field, was channeled into the magnetic field lines, converged at the poles, and induced electric currents at the higher latitudes (Fig 1). Where the ground was conductive, the geomagnetically induced currents flowed harmlessly through the ground.

But on the Canadian Shield, the resistive igneous bedrock forced the



2. Areas with igneous bedrock, located inside the dashed lines, are at higher risk of geomagnetically induced current (color) current to seek easier conductance (Fig 2). It entered the electric grid through ground wires and propagated throughout Hydro-Quebec's system. Within 92 seconds it brought down almost the entire grid, knocking 21,500 MW off line. The blackout lasted more than nine hours, affected six million people, and cost $2 billion.

During the cold war, alarms occasionally were sounded in the news about the threat of attack by a lone hostile missile over the US, which with a thermonuclear explosion could emit an enormous high-altitude electromagnetic pulse, frying every piece of electronics in a multistate area and bringing our entire electricity- and electronics-dependent society to its knees. The feared attack never came from a hostile power, but the March 1989 solar eruption provided an object lesson in the vulnerability of North America's electric power systems to such exotic incidents.

Quebec's system was the most obvious victim of that event, but power systems throughout North America, including the US, experienced more than 200 related transformer and relay problems. The most serious was the loss, from overheating and permanent insulation damage, of a $12-million, 22-kV generator step-up transformer at the Salem Nuclear Plant, Hancocks Bridge, NJ (Fig 3). Even with a spare transformer available, the plant was offline for 40 days, entailing millions of dollars in lost power sales and replacement power purchases, in addition to the replacement cost of the transformer.

A new maximum

"Space weather" is not unusual, and the storm that blacked out Quebec is far from being the most powerful on record. Now the sun is ramping up to a new maximum, which will produce a new wave of solar magnetic storms, threatening power systems globally. The solar maximum is accompanied by an increase in the frequency of two space weather events—solar flares and coronal mass ejections (CME).

Solar flares blast X-rays into space along with masses of protons and electrons traveling nearly at the speed of light. A CME is an immense, billion-ton bubble of plasma and magnetic fields travelling at speeds exceeding a million mph. These eruptions occur all over the sun's surface, and almost always are directed into empty space.

Occasionally, however, a flare or CME that occurs on the surface facing the Earth strikes our home planet more or less directly. When that happens, the solar flare can disrupt short-wave communications; the CME creates a geomagnetic storm that engulfs the Earth, triggering spectacular auroras in the skies

3. Saturation caused overheating in this transformer, irreparably damaging its winding

1. What happens in a geomagnetic disturbance

A report by the North American Electric Reliability Corp (NERC), Princeton, NJ, explained, "As the solar particles arrive at Earth, they cause rapid fluctuations of Earth's geomagnetic field. This, in turn, produces an induced earth-surface potential and geomagnetically induced currents, or GIC. GIC appears as a quasi-dc current (an ac waveform with a period of several minutes), and for all intents and purposes, appears as dc to the bulk electric system."

GIC is substantial, said Richard Lordan, a senior technical executive at the Electric Power Research Institute, Palo Alto, Calif. If you could insert a voltage probe in the East Coast and another in the West Coast, they could reveal a voltage differential across the US of as much as 10 V/km, he said.

"The consequences of this dc current is [sic] to drive transformer cores into saturation," the NERC report continued. "This, in turn, causes significant heating from stray flux, increases VAr losses that depress system voltages, and can damage the transformer itself. Core saturation can also generate harmonic distortion that impacts other elements in the electric system."

Those impacts "can jeopardize the integrity of the bulk electric systems" by causing overcurrent relays to trip capacitor banks, or static VAr compensators to trip for overcurrent or overvoltage protection, said the NERC report.

Tripping a large quantity of reactive resources during a GMD can further depress system voltages already reduced by transformer VAr losses. The result could be to precipitate a multiple-contingency incident in an electric system mostly designed only for single-contingency operation. In a word, it would cause an immense, long-lasting, extremely costly blackout.

As the loss of the Salem Nuclear Plant's transformer attests, equipment damage is one possible consequence of such an event. NERC explained, "Depending on the location and concentration of stray flux internal to the transformer, heating of the oil, and relative equipment health, hot spots can emerge on tank or core locations, internal windings, and other structures within the transformer and can damage the transformer insulation systems.

"Further, during saturation, the reactive demands increase proportional to the transformer operating voltage (that is. a 765-kV transformer will produce twice the MVAr demand as a 345-kV transformer with the same level of geomagnetically induced currents), and it emits substantial amounts of both even and odd harmonics making traditional relaying challenging."

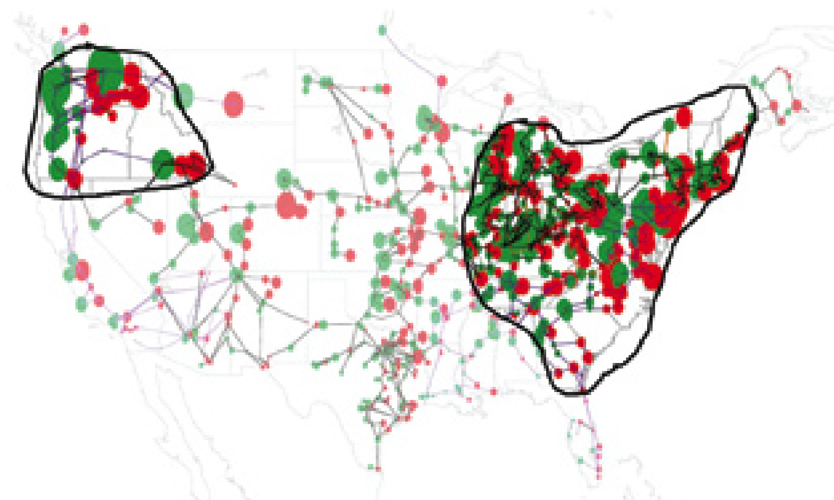
Heat damage or torsional damage could also appear on the generator/turbine shaft system, said John Kappenman, a leading expert on GMD and owner of Storm Analysis Consultants, Duluth, Minn. "Protective systems on the generator may not be well suited to detect this threat."

Really big CMEs affecting Earth are "quite infrequent," said Kappenman, but "as we see more [sun] spot activity, we will see more coronal mass ejections from those spots." Big CMEs actually occur all the time, he notes, but they don't affect Earth unless they are directed at us. "It's a bit of a Russian roulette game with the sun that one is playing here," he said.

over the higher latitudes and an Earth-level geomagnetic disturbance (GMD) that can cripple modern electric systems.

GMDs of varying intensity have always struck Earth, but they have become especially destructive since the mid-19th century, when the invention of the telegraph led to the development of a system of wires that offered a path for geomagnetically induced current (GIC). Most often cited are the superstorms of May 1921 and September 1859.

The 1921 storm, considered a 100-year storm, generated auroras seen in Samoa, 13 degrees off the geomagnetic equator. In the US, it virtually ended telegraph service east of the Mississippi River and disrupted service in at least six cities in the West all the way to San Francisco.



4. An intense GMD centered on latitude 50 north could cause power systems to collapse in the outlined areas, affecting more than 130 million people

The 1859 storm was the largest ever recorded. Known as the Carrington event for the British astronomer, Richard Carrington, who witnessed the white-light solar flare that generated it, the superstorm created havoc in the young telegraph network. Some operators were able to use their systems without batteries thanks to the induced current in the wires. Others scrambled to escape the fires that broke out in their offices when their wires melted and sparks from their keys ignited papers.

Those events occurred when electric power systems were far less developed and interconnected than they are now. Our understanding of the GMD threat to the bulk electricity system is still limited, said Mark Lauby, VP/director of reliability assessment and performance analysis for the North American Electric Reliability Corp (NERC), Princeton, NJ. The system's vulnerability has grown with the increasingly interconnected and sophisticated grid, as well as with the burgeoning use of consumer electronics of all kinds (Fig 4).

The 1989 storm that brought down the Quebec grid and damaged a transformer in New Jersey was the alarm that awoke the industry to the threats from solar weather. It has been intensively studied for its lessons. In January 2011, NERC launched a task force to determine the industry's baseline risk. Transformers now are "more robust," said Lauby, but we still lack a statistical basis for defining a 100-yr storm and the theoretical maximum storm. Working out those definitions is part of the task force's mission.

Analysis of Arctic ice cores suggests that the Carrington event was a 500-

yr storm, but astronomers say storms half as strong occur at about 50-yr intervals. Today, instead of telegraph systems, satellites will be among the most affected systems, in addition to the electric-power grid, which acts as an antenna with multiple ground points providing a path for GIC into the system. A report by the National Academy of Sciences estimated that the cost of recovering from a Carrington event today could be $1-$2 trillion, and recovery and restoration could take four to 10 years.

Space-weather forecasts don't yet meet the AccuWeather standard, so predictions are more art than science. A panel of experts sponsored by the National Oceanic and Atmospheric Administration (NOAA) convened in 2009 on solar disturbances predicted sun-spot activity would be below normal, peaking in 2013. Some panel members, however, still predicted the coming solar max could produce a storm similar to the Carrington event. "There is no correlation between sunspots and CME intensity," said Richard Lordan, a senior technical executive at the Electric Power Research Institute (EPRI), Palo Alto, Calif. Furthermore, "There are no organizations that I know of that predict the severity of the storms for a given cycle."

There are two kinds of predictions of space weather threats, said Lordan. NOAA issues an alert when a CME occurs if it is likely to affect electrical systems. That gives about a day's warning. The other prediction comes from the ACE space satellite, located at the gravitational center between Earth and sun, about 1 million miles out. When the CME passes, it monitors its characteristics and the information provides 30-60 minutes of warning for informed preparations by system and powerplant operators.

At risk

Transformers are the generation infrastructure most at risk from a geomagnetic disturbance (Sidebar 1), but other equipment also is exposed. "Potential effects include overheating of auxiliary transformers; improper operation of relays; heating of generator stators; and possible damage to shunt capacitors, static VAR (volt-ampere-reactive) compensators, and filters for high-voltage dc lines," added an article in the spring 2011 issue of *EPRI Journal*.

One lesson the industry has learned from the 1989 Quebec storm is that operators now widen the operational region of sensitive equipment to withstand a wider range of voltages, said Lordan. When the generator step-up transformer at a powerplant receives a GIC, it can produce harmonics creating imbalance in the rotor of a generator, he said. The immediate effect is small, but it can accelerate equipment aging.

Powerplant operators have at least two main ways to protect their equipment from damage in a geomagnetic storm, said Buddy Dobbins, director of machinery breakdown in the Risk Engineering Dept of Zurich Services Corp, Schaumburg, Ill. They can take equipment offline when NOAA issues a warning of a CME or they can harden transformers against geomagnetically induced current.

"The industry probably needs to look at how to harden its systems against this disturbance," said John Kappenman, a leading expert on GMD and owner of Storm Analysis Consultants, Duluth, Minn. System hardening requires blocking a GIC from entering the transformer in the neutral-to-ground connection, he said. In 2010, while he was with Metatech Corp, Goleta, Calif, Kappenman prepared a report for Oak Ridge National Laboratory in Tennessee describing the alternatives.

Inserting a capacitive device in the transformer neutral-to-ground connection would block all dc flow,

2. In case of GMD. . . .

You have just received an alert from NOAA that a coronal mass ejection has occurred and a geomagnetic disturbance may occur. Here is what NERC said to do in an Industry Advisory on May 10, 2011.

1. Increase import capability:

- Discontinue non-critical maintenance work and restore out-of-service transmission lines, wherever possible.
- Evaluate postponing/rescheduling planned outage and maintenance activities.

2. The reliability coordinator may instruct generator operators to increase real and reactive reserves to preserve system integrity during a strong GMD event by performing such actions as these:

- Reducing generator loading.
- Evaluating generator re-dispatch mix to implement.
- Bringing equipment online that is capable of providing reactive power—such as generators, synchronous condensers, static VAr compensators, etc.

3. Transmission and generator operators should increase attention to situation awareness and enhance surveillance procedures. Reliability coordinators should be informed of all actions, such as when:

- Unusual voltage and/or MVAr variations and unusual temperature rises are detected on transformers and generators.
- Abnormal noise and increased dissolved gas is found on transformers where such monitoring capability exists.
- Trips by protection or unusual faults that are detected in shunt capacitor banks and static VAr compensators.

Now, assume you have been notified . . .

. . . that a severe GMD is to be expected within 30 to 60 minutes. Before you detect increased baseline GIC levels, do the following:

1. Increase reactive reserves and decrease loading on susceptible equipment, and coordinate actions with the reliability coordinator, such as the following:

- Bring additional equipment online to provide additional reactive power reserves.
- Increase dynamic reactive reserves by adjustment of voltage schedules or other methods. Caution: raising voltage levels may place transformers closer to saturation.
- Reduce power transfers to increase available transfer capability and system reactive power reserves.
- Decrease loading on susceptible transformers through reconfiguration of transmission and re-dispatching of generation.

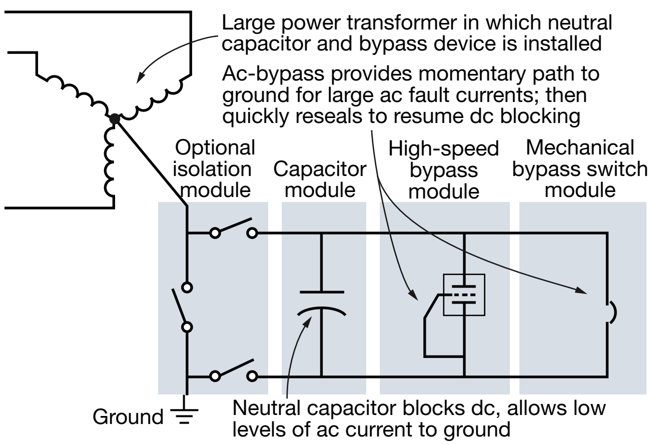
2. Increase attention to situation awareness and coordinate information and actions with the reliability coordinator, such as:

- Reducing power output at susceptible generators if erratic reactive power output from generators or excess reactive power consumption by generator step-up transformers is detected.
- Removing transmission equipment from service if excessive GIC is measured or unusual equipment behavior is experienced and the system effects of the equipment outage have been evaluated.

but could risk impedance changes and ferroresonance concerns on the network, it said. A simpler, low-ohmic resistor in the neutral-to ground connection in all transformers on the power grid would achieve only partial GIC reduction, but would be more reliable and less costly.

The resistor would reduce GIC by 60% to 70% for a parts-and-installation cost of about $8000, Dobbins said. "It's relatively easy to install and thus prevent those effects." Retrofitting all the most critical transformers in the US would cost $150 million to $200 million, he said. That cost compares favorably to the alternative possibility of losing a transformer. That is a potential problem because the manufacturing capacity for such large equipment is not available on the scale that might be required in the aftermath of a serious superstorm, he continued.

Some companies are developing the technology and have demonstrated the hardware. Phoenix Electric Corp, Boston, Mass, developed a GIC blocking device with Kappenman in the mid-1990s. In an EPRI-sponsored project in 1997, Phoenix installed two prototypes in transformers owned by Minnesota Power and simulated an injection of direct current into a 500-kV transformer.



5. Neutral-blocking device from Phoenix Electric Corp can be set to allow ac to bypass it in case of a voltage surge

"Those transformers didn't like it," said Stephen Simo, Phoenix SVP. The project's main aim was to test the operation of the bypass in the neutral-to-ground connection that would pass an ac surge to ground before it could damage the transformer, while still blocking dc flow, said George Sweezy, Minnesota Power's supervising engineer for system operation and performance.

The project lasted three years. Sweezy admits GIC is a concern for his utility, located as it is in a northerly latitude, but says series capacitors now installed on the region's 500-kV transmission grid also protect the transformers.

Phoenix Electric has not installed any of the devices since then, but is reviewing the design and evaluating the market for them, said Georgia Beyersdorfer, manager of marketing. "Scientists believe the problem has grown dramatically," said Simo. If another coronal mass ejection blasts the Earth, "we are not prepared to lose transformers in the grid."

Phoenix's new blocking device can be activated by the utility when a solar weather forecast warns that GIC is expected. The default setting is in the bypass mode, but the utility can set the dc blocking mode and bypass to operate in microseconds if the device detects an increase in ac

larger than 8 kV, said Simo.

After the bypass operation, the utility can return the device to blocking operation, much as it would reclose circuit breakers after a surge (Fig 5). Simo said he thinks the device will be ready for market about mid 2012.

Two other US utilities queried for this article said they are aware of the potential threat from CME, but they have not invested in equipment to harden their systems. "Geographically, we've seen very little. We just really haven't encountered" GIC, said Susan Gallager, spokeswoman for Ameren Corp, St. Louis, Mo. "We track solar activity and subscribe to services that monitor and forecast this activity," but "we haven't experienced any difficulty in our recent history," she said.

Southern Company, Atlanta, also takes a low-key approach. "Solar flares are most likely to impact high-latitude regions of the Northern Hemisphere, which are not inside Southern's service territory," said spokeswoman Stephanie Kirijan. The utility "continues to investigate how increased magnitudes of solar flare events might ultimately impact electric grid operations," and is working with both EPRI and NERC on studies of GMD effects, she said.

Seeking shelter from the storm

Ontario Power Generation, the largest generation utility in the Canadian province of Ontario, is well aware of the problem, being a neighbor to Hydro-Québec and, like that utility, sitting on the Canadian Shield. Ontario's power grid is operated by Hydro One and is controlled by the Independent Electricity System market operators.

Gian di Giambattista, OPG's director of emergency management and business continuity, said "the transformer is the most critical piece of equipment" that requires protection from GMD in OPG's inventory, and he is focused on understanding what happens within transformers when they occur. He said OPG is working with NERC and its Ontario industry partners on ways to protect powerplant equipment.

Citing company policy on security, he declined to say how OPG protects its equipment from hazards and threats. "I can substantiate that since the 1989 [solar magnetic disturbance] cycle there has been a lot of R&D and the understanding how to mitigate them is much better today," he added.

In May 2011, however, a NERC advisory warned, "While the impacts of geomagnetic disturbances in the Northern Hemisphere have been primarily observed in the northern latitudes, a severe GMD can reach the central and southern portions of the US."

In such an event, NERC would call on generation operators "to increase real and reactive reserves to preserve system integrity" through measures such as reducing generator loading, evaluating the generator redispatch mix to be implemented, and bringing on line equipment such as generators, synchronous condensers, and static VAr compensators that can provide reactive power (Sidebar 2).

Since 2008, the Dept of Homeland Security, NERC, and other stakeholders have actively studied and consulted on the potential threat from the coming solar max. The NERC task force on GMD now "is investigating and fully vetting bulk power system reliability implications of geomagnetic disturbances, assessing available studies and associated models, and developing interconnection-wide technical solutions that are complete and accurate," wrote Gerry Cauley, NERC President and CEO, in a letter to industry in June 2011.

The task force is trying to determine what actually constitutes a 100-yr storm and what is the theoretical maximum of a GMD, said Mark Lauby, NERC VP/director of reliability assessment and performance analysis. The 1921 storm has been called a 100-yr event, but that is "speculative," he said. "We have little working data before 1989." The challenge to the industry is that our ability to forecast storms is low, he said. The GMD task force is scheduled to complete its final report and issue recommendations in 1Q/2012. "They will probably be suggesting additional work," he said.

NASA and EPRI are working on improving the short-term forecasting capability and have completed study of a forecasting system called Solar Shield. "One of the major near-future updates will include capability to model and forecast GIC also at lower geomagnetic latitudes," said Antti Pulkkinen, associate research scientist at NASA's Goddard Space Flight Center, Greenbelt, Md. "We are also supporting NERC Geomagnetic Disturbance Task Force activity in terms of providing geophysical estimates for 100-yr GIC events. These results can be used in further engineering analyses carried out by power engineers." CCJ

Renewables-era combined cycle meeting expectations

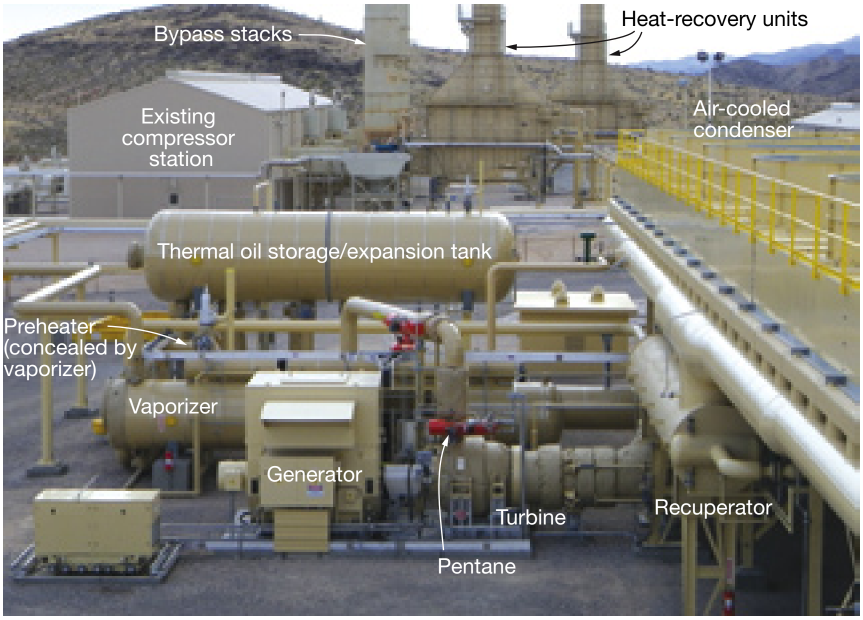
When you mention the term "combined cycle" to colleagues in the electric power industry, they generally assume you're referring to a gas turbine/generator coupled to a steam turbine/generator by means of a heat-recovery steam generator.

But that's not necessarily the case. Another type of combined cycle, one offering renewables credits, marries a gas turbine/compressor and an expander turbine/generator. Here, a conventional heat exchanger and thermal fluid are used to transfer energy from the Brayton cycle's gas-turbine exhaust to the low-boiling-point organic working fluid driving the Rankine cycle's expander. Vapor exiting the expander often is returned to the liquid state in an air-cooled condenser. The Goodsprings Energy Recovery Station is a case in point (Figs 1, 2).

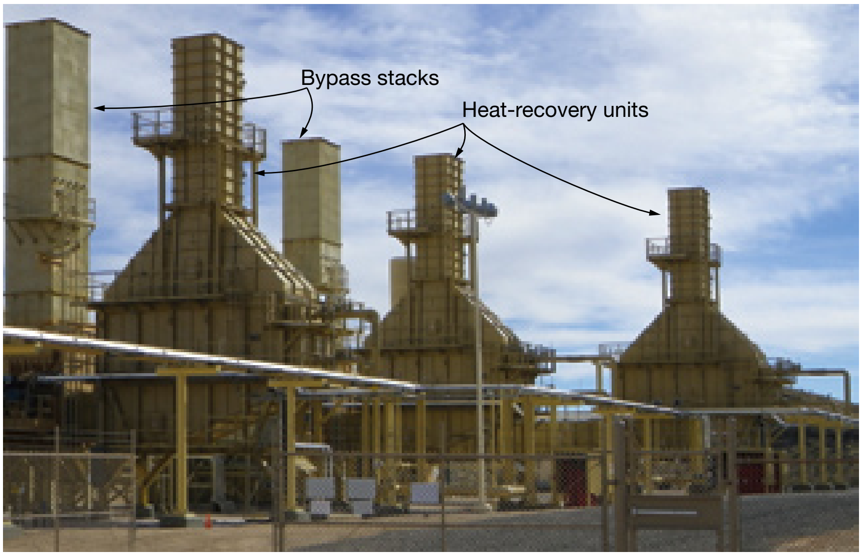
Ormat Technologies Inc, Kern River Gas Transmission Co, and NV Energy came together to assure the commercial success of the 7.5-MW Goodsprings project located 35 miles south of Las Vegas near the California border. It began commercial operation at the end of 2010.

Ormat, based in Reno, Nev, provided the ORC (organic Rankine cycle) and heat-recovery technology; it also manufactured key equipment and served as the EPC contractor. Kern River supplies the heat to vaporize the pentane working fluid. NV Energy is the project owner and electricity off-taker. Ormat is operating and maintaining the unmanned plant for its first three years of service.

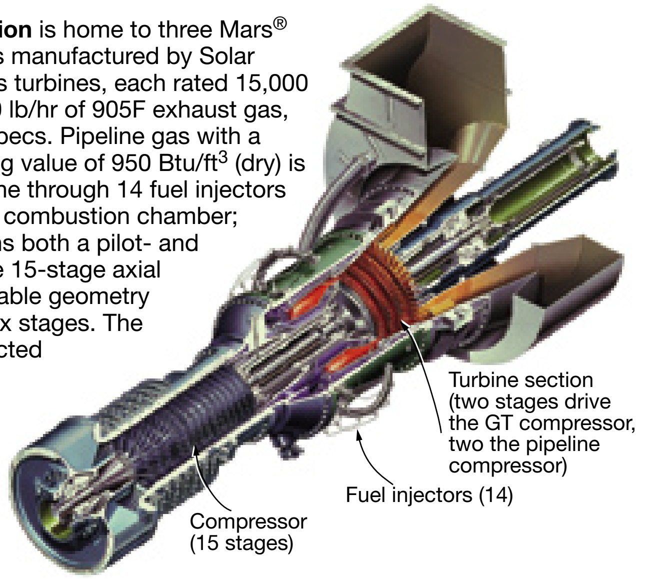
Goodsprings is southern Nevada's first non-solar renewable energy project and also the first renewable energy project *owned* by the state's largest utility. Note that NV Energy has 46 separate geothermal, solar, biomass, small hydro, wind and waste-heat recovery projects under contract—either in commercial operation or under development.



1. Goodsprings Energy Recovery Station recently completed its first year of commercial operation, meeting expectations



2. Heat-recovery units look much like one-through HRSGs. They transfer heat in the gas-turbine exhaust stream to a thermal fluid, which, in turn, heats the pentane working fluid for the organic Rankine cycle



3. Compressor station is home to three Mars® 100 compressor sets manufactured by Solar Turbines Inc. The gas turbines, each rated 15,000 hp, produce 338,000 lb/hr of 905F exhaust gas, according to Solar specs. Pipeline gas with a nominal lower heating value of 950 Btu/ft^3 (dry) is supplied to the turbine through 14 fuel injectors mounted around the combustion chamber; each injector contains both a pilot- and main-fuel circuit. The 15-stage axial compressor has variable geometry stators for the first six stages. The compressor is inspected semiannually with a borescope; regular cleaning by washing with water and detergent maintains top performance

The company's renewable energy portfolio totals more than 1200 MW. In 2010, the utility exceeded the state-legislature-mandated Renewable Portfolio Standard of 12% kilowatt-hours from renewables as well as the solar carve-out of 5%—a first-time accomplishment.

NV Energy is no stranger to combined cycles or to dry cooling. It owns and operates eight E- and F-class 2 × 1 combined cycles at six stations. ACCs serve six of the existing combined cycles. Get details on the utility's generating plants at www.ccj-online.com/archives, click 2Q/2009.

In terms of electric output, Goodsprings is larger than it appears. While rated only 7.5 MW, it is expected to operate at a capacity factor of 90% or greater, making the plant equivalent to a 25-MW solar or wind facility. Capacity factors of 30% are typical for wind and solar.

Performance for the first year was close to expectations. The capacity factor was lower than planned because the volume of gas transported last winter on the Kern River pipeline was less than normal over a period of several weeks. Equipment operated satisfactorily for the most part. An availability north of 95% is expected for a mature plant; a little less in Year One. O&M costs were within the 2011 budget; they are projected to decrease slightly in the coming years.

At the plant dedication in November 2010, Kern River President Gary Hoogeveen told the guests that his company is an advocate of increasing energy efficiency and of reducing greenhouse gas emissions. He added that if Goodsprings meets expectations, Kern River, owned by Warren Buffett's Des Moines-based MidAmerican Energy Holdings Co, would likely invest in other heat-recovery projects along its 1707-mi pipeline from southwestern Wyoming to Southern California.

The Kern River system has 12 compression stations with a total installed capability of 384,220 hp. It carries 2.14 billion ft^3/day, or three times the system's capacity when it was placed in service in February 1992. More than 1300 of the line's 1700 miles are made of 36-in.-diam stainless steel pipe. Operation is 8760 hr/yr.

The Goodsprings Compressor Station is the last booster facility on the system before gas reaches the only compression station in California near Daggett. It was part of the original network and declared operational in early January 1992 with three Mars® 90 (Solar Turbines Inc, San Diego) natural-gas-fired simple-cycle compressor drivers rated at about 11,000 hp each (Fig 3). A 525-kW emergency gas engine/generator and a 3.85-million-Btu/hr gas-fired boiler support station operations.

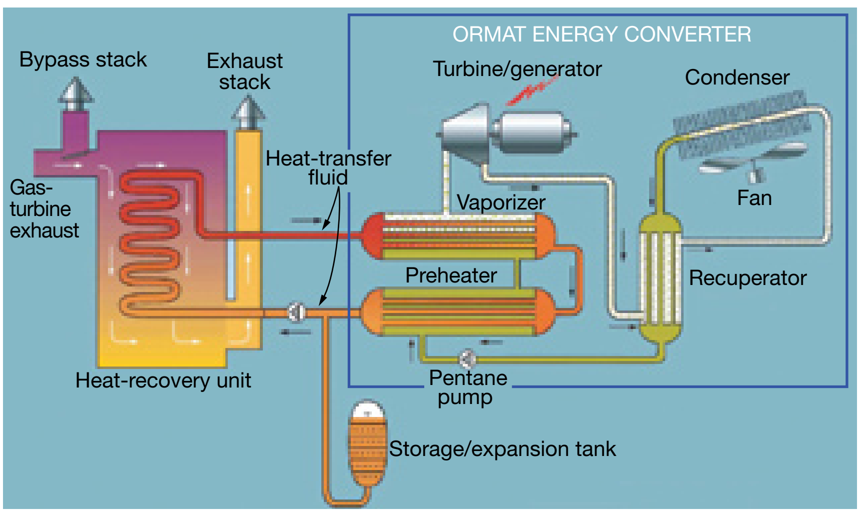
The Goodsprings operating permit required Kern River to install a new low-NO_x combustor that was under development by Solar at the time the station was built. That modification had to be implemented before the first scheduled major overhaul after the new combustion system became available.

The original permit allowed 170 ppmvd of NO_x at 15% O_2 and mass emissions of 237.3 tons/yr. After the upgrade to Solar's SoLoNO$_x$ combustion system in 1996, a new operating permit was issued. It reduced allowable NO_x emissions to 42 ppm and 72.3 tons/yr. Performance test results confirmed compliance. The reduction in mass emissions dropped Goodsprings' status from "major" source to "minor" for all regulated pollutants.

A subsequent revision to the operating permit removed all CEMS (continuous emissions monitoring system), PEMS (predictive emissions monitoring system), and quarterly reporting requirements. However, annual compliance reporting is still required; plus, turbine performance is monitored continuously by PEMS, but not reported.

In spring 2001, Kern River requested and was given permission to upgrade one of the Mars 90s to a Mars 100 with a 15,000-hp rating—this to raise system pressure and increase gas flow through the pipeline. An ATC (authority to construct) was issued in fall 2002 to upgrade the remaining two Mars 90s to 100s. At that time, a limit of 16 ppmvd CO (quarterly average of hourly values) was imposed on all three engines.

Kern River's SCADA (supervisory control and data acquisition) system allows it to continuously monitor emissions and operating parameters at all



4. Organic Rankine cycle is designed to recover low-grade heat and convert it into electricity. Pentane is used as the working fluid at Goodsprings compressor stations on a real-time basis. This is critical to company goals for maintaining emissions compliance and expected maintenance intervals. For example, power-turbine inlet temperature is monitored to assure hot-gas-path parts are not subjected to potentially damaging over-temperature conditions; bleed-valve operation is monitored to assure a relatively flat emissions profile.

Participation in the ORC project was simply Kern River's latest effort for improving the performance and reducing the environmental impact of its pipeline infrastructure. ORC plants ranging in capability from a few hundred kilowatts to a few megawatts have been installed by many different owners over the last 25 years or so to recover energy from heat rejected by industrial processes as well as that available in diesel-engine jacket water and geothermal resources.

In the oil and gas sector, the leader in heat recovery from pipeline compression facilities is ONEOK Partners LP, Omaha, the owner/operator of a 42-in. line carrying 2.5 billion ft^3/day of Canadian gas to midwestern markets. At least four of its compressor stations have been retrofitted with Ormat Recovered Energy Generation (REG) systems. TransCanada Pipeline's Cold Creek Compressor Station has been producing 6.5 MW reliably since 1999 under demanding ambient conditions in Alberta.

Ormat perhaps is best known for its worldwide development, operation, and maintenance of geothermal plants. In that generation sector, Ormat Energy Converter (OEC) systems based on the ORC are used to extract heat from wells yielding medium-temperature brines (Fig 4). Plus, they also serve in bottoming cycles to maximize power production in plants using high-temperature geothermal resources to first drive a steam turbine.

ORC efficiency typically ranges from 10% to 20% depending on the temperature of the heat source. An economically viable, megawatt-size system probably would require a heat source with a minimum temperature in the 280F-290F range. Also, the ORC would have to be located near the heat source and a cooling medium to condense the vapor.

Here's how REG works: Gas-turbine exhaust heat is transferred to a thermal fluid circulating through the recovery unit shown at the left in the diagram. The hot thermal oil provided to the OEC boils organic fluid (pentane at Goodsprings) in the vaporizer and then gives up some of its remaining heat to pentane in the preheater before returning to the recovery unit.

Vaporized pentane expands through the turbine and flows to the recuperator where it warms the ozone-benign, organic working fluid returning from the air-cooled condenser. Use of an ACC eliminates the expense associated with permitting, installing, operating, and maintaining a water treatment system which would have been significant—if possible—given the desert environment surrounding Goodsprings.

The attributes of pentane. The thermodynamic properties of pentane allow much higher condensing pressures than are possible for steam. This permits use of shorter turbine blades and minimizes ingress of air into the system. The latter mitigates the need for vacuum maintenance.

Another plus is that the saturation curve for hydrocarbons is such that the working fluid remains dry under all operation conditions—thereby eliminating the possibility of erosion damage to turbine buckets and nozzles often found in steam systems. CCJ

Ovation users glimpse the future, consider today's solutions

No sector of the electric power industry seems to change as fast as automation, control, and digital technologies. Part of that change is intrinsic as suppliers adapt their systems to reflect the dizzying advances in computing and processing power, and executives controlling the purse strings seek perpetual cost reductions. But part of that change is extrinsic too, as programmers battle the forces of evil in cyber security and oversight of regulators for reliability.

All of these forces were amply illustrated at the Ovation Users' Group meeting sponsored by Emerson Process Management Power & Water Solutions, last July, in Pittsburgh (sidebar).

It might come as a surprise to some to some in the industry how dominant Ovation® is, having "proved its performance" at the majority of North American generating facilities powered by gas turbines. Over the last three years, in particular, Emerson has had major success in the retrofit of control systems for GTs.

This includes 15 engines for Luminant in Texas, six units for Duke Energy in North Carolina, three units at Xcel Energy's Fort St. Vrain combined-cycle facility and two peakers at the same location, and two units at Comision Federal de Electricidad's (CFE) Valladolid combined-cycle plant. These facilities represent Siemens 84.2, General Electric 7FA and 7EA, and Alstom GT11 machines.

Contributing to Emerson's success is its alliance with Mitsubishi Power Systems Americas Inc, Orlando, Fla, to provide complete automation solutions for all gas-turbine models developed by Mitsubishi during the period of its alliance with Westinghouse Electric Corp in the 1980s and 1990s—prior to the latter company's acquisition by Siemens AG of Germany.

Under this agreement, five engines already have been upgraded and improved with such features as the following:

- Improved overspeed protection.
- Inlet-guide-vane (IGV) logic improvements for off-line washing.
- Better control methodology following a loss-of-flame incident.
- More reliable fuel-oil ignition.
- Tighter automation of fuel valve operation.
- Safer generator limit protection.

Ovation also has been retrofitted during projects with PSM, Jupiter, Fla (10 machines)—including four at NV Energy's Edward W Clark Generating Station (access "Complete makeover," 2Q/2009 at ccj-online.com). In addition to Ovation's accomplishments, all of the 300 PLC-based controls projects of the former Innovative Control Systems, Clifton Park, NY, became part of Emerson's bragging rights after its acquisition of ICS in June 2010 (access "Stony Brook Energy Center," 2Q/2010).

It doesn't take long for a controls retrofit to pay for itself when you get 8 MW of additional output and reduce annual maintenance costs by $30K. That's what personnel from a Gulf Coast cogeneration plant reported at the conference. Engineers there expanded the original Ovation infrastructure by replacing the ABB Advant steam turbine controls and adding them into the Ovation scope. Some of the salient features of the retrofit include:

- Original cabinets were gutted, signal conditioners remounted, and terminations made between Ovation modules and original terminal blocks. The origi-

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Board members (2011)

President: Daniel Noles, *TVA*
Vice President: Lem Mixon, *Eastman Chemical Co*
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Alex Brumfield, *Southern Company Inc*
Bill Collins, *Constellation Power Source Generation Inc*
Fred Cox, *Hampton Roads Sanitation Dist*
David Dickhaut, *Progress Energy*
Joel Erwin, *Dynegy Midwest Generation*
Anil Gosine, *Detroit Water & Sewage Dept*
Carl King, *Duke Energy*
Mike Lehman, *Duke Energy*
David McMullan, *Xcel Energy*
Mark Wahl, *Suez-DEGS of Rochester LLC*
Hsiu-Chen Wang, *Con Edison Co of NY Inc*
Wes Weaver, *Southern Company Inc*
Wes Whitley, *Alliant Energy*
Scott Woodby, *Midland Cogeneration Venture*

nal field wiring was retained.

- Existing 24-V dc power supplies were retained but diode auctioneering added for switchover
- Demolition and installation complete in five days.
- I/O checkout completed in five days.

Plant personnel also reported that tighter control and monitoring has reduced the risk of equipment damage.

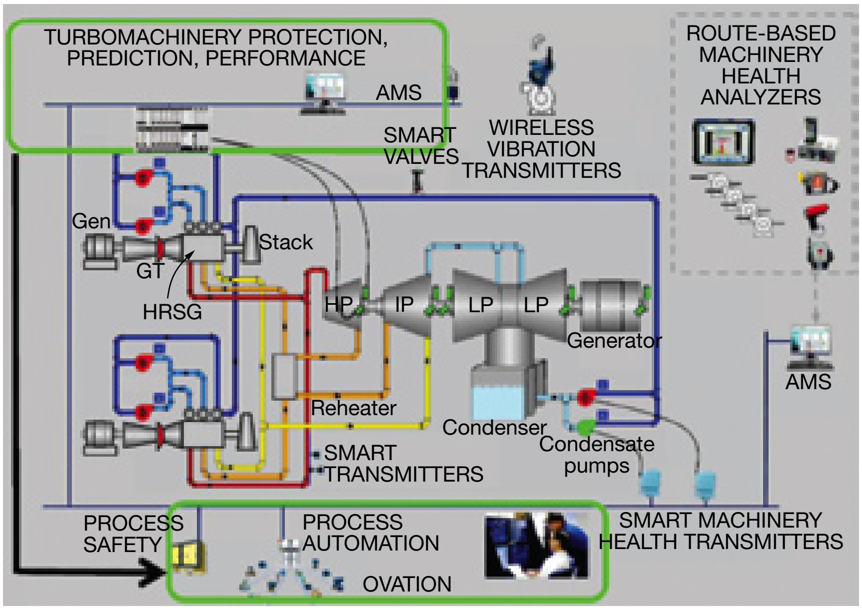
Machinery health

Emerson acquired Computational Systems Inc (CSI) and the Westinghouse Process Control Div almost 15 years ago. You might not think it would have taken several years for the company to offer "easy integration" of the CSI 6500 machinery health protection system with Ovation (Figs 1, 2). However, most readers recognize that the organization changes much slower than the name on the door after an acquisition.

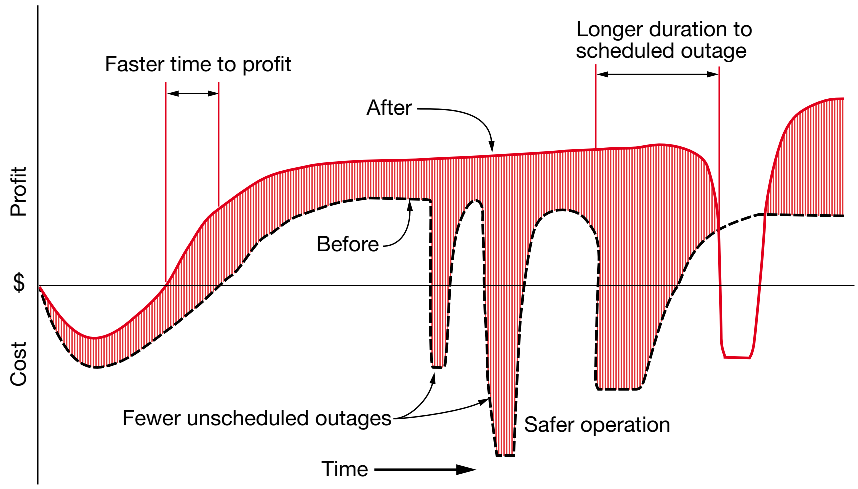
Today, you can do what's necessary in 10 minutes, reportedly, with three steps—scan the CSI hardware (HW), select parameters and alarms, and import to Ovation. The graphical user interface is a cinch because all macros are pre-defined and available from the library.

The new procedure, which supports Modbus and Modbus-r Ethernet, is compatible with all Windows versions back to v.2.4, and will shave three weeks off of the commissioning schedule, according to Emerson engineers.

The only cautionary note is that you must have an available I/O device on the controller to define as the Modbus master.



1. Scan, select, import—a three-step process said to take less than 10 minutes is all that's required now to integrate CSI 6500 machinery protection system with Ovation



2. Easy integration reduces chances for human error and hastens the benefits your plant will obtain with advanced machinery protection

Alarm management

Rationalizing alarms has been a hot topic over the last several years, mostly as an unintended consequence of sophisticated automation systems.

The majority of alarms have to do with the control system itself, not the process. Developing an alarm management strategy starts with an understanding of best practices and standards and an analysis of alarming trends at your facility.

As a quick guide, compare the number of alarms you think your operators are dealing with to the benchmark (Fig 3) set by the Engineering Equipment and Materials Users Assn (EEMUA, www.eemua.co.uk). Chances are your facility has room for improvement given the

Unacceptable	Unmanageable	Demanding	Manageable	Acceptable
More than 60 alarms/hr	30-59 alarms/hr	12-29 alarms/hr	6-11 alarms/hr	Fewer than 6 alarms/hr

EEMUA-191 benchmark: Calculated as number of alarms per hour per operator

3. Industry benchmark will give you a rough idea of whether your facility faces alarm management issues

Parameter	EEMUA	ISA	Oil/gas	Petrochem	Power	Other
Average alarms/day	150-300	150-300	1200	1500	2000	900
Average standing alarms	9	4	50	100	65	35
Peak alarms per 10-min period	10	10	220	180	350	180
Average alarms per 10-min period	1-2	1-2	6	9	8	5
Distribution, % (low-mid-high)	80-15-5	80-15-5	25-40-35	25-40-35	25-40-35	25-40-35

4. The typical powerplant has a long way to go regarding alarms to match best practices across comparable industries

Ovation now world's top-selling DCS

It's tough following the keynote speaker at any industry event, especially one urging several hundred coffee-drinkers to "Make Some Noise: Open the Throttle and Create a Culture of Innovation," and having some spectacular biker footage to share.

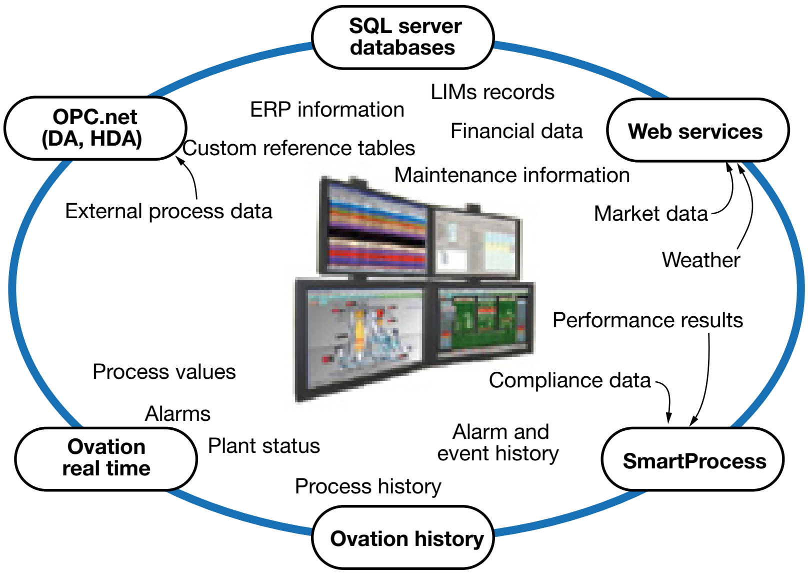
Ken Schmidt, a former communications director for Harley-Davidson, dressed for the open road on "America's cycle" revved up the Ovation and WDPF users with an upbeat presentation that reinforced Yogi Berra's famous line, "It ain't over till it's over." H-D was almost out of business some years back, Schmidt told the group, pressured by formidable foreign competition. But innovative marketing, sound engineering, and a "never say die" attitude restored the company to its pre-eminent position in the cycle world.

As the "bike buzz" and excitement subsided, Bob Yeager, president, Emerson Process Management, Power & Water Solutions, stepped to the podium. His presentation, without film and engine noise, told a different kind of success story. It related the brief history of the Ovation expert control system, launched in 1997 as the backbone of a relatively insignificant burner management system for a fossil-fired utility boiler.

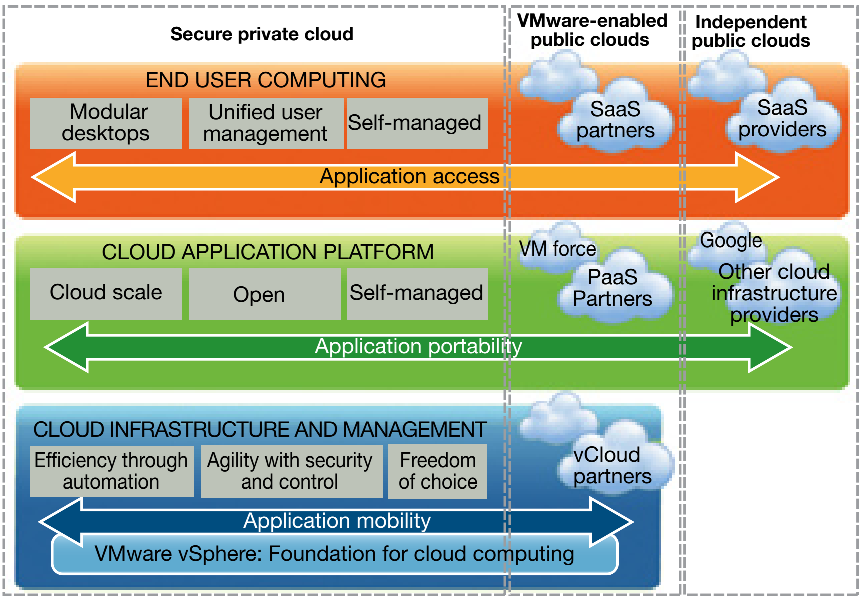
Yeager proudly announced that that humble start together with generous amounts of inspiration, ideas, and innovation—the theme of the 2011 Ovation/WDPF Users' Group Conference—had made Ovation the global leader in DCS systems for power generation applications with a 22% market share. Today the Ovation name is associated with more than 800,000 MW of generating capability worldwide.

industry level comparison shown in Fig 4.

The important thing to remember, according to Ovation alarm experts, is that alarms need to be tuned just like any other critical parameter to make sure they are meeting the need for safe operation. Periodic review should include: failed sensor transmitters, high-low limits, proper dead band calculations, use of alarm cutouts and time delays, and general assessments.



5. More and more information is made available to the operator through the Ovation process display graphics to achieve a sophisticated level of "situational awareness"



6. Cloud architectures include public and private deployment areas

NERC CIPS

The new critical infrastructure protection standards (CIPS) are a minefield unto themselves. It is difficult to provide generic guidelines, since everything becomes exceedingly site specific, especially whether a facility is even considered a critical asset. However, worth contemplating are some of the more illuminating facets of a comprehensive cyber security program involving Emerson and a major utility in the Southeast:

- Three separate vendor networks are involved at one of the utility's combined-cycle facilities, which has been identified as a critical asset, and was under construction when the program got underway. Ovation Security Center is being used for overall system protection, which, among other things, has to address patch management for all three networks.
- Four major areas of impact were identified for the plant—identifying and handling protected information, network design, process system security design, and physical security perimeter design.
- At least two teams were established—the Ovation Cyber-Emergency Response Team, and the Emerson Security Solutions Steering Committee. The former

handles known security threats and impact on Ovation systems, the latter recommends products, services, and changes to the business in relation to security.

- A test-bed simulator representative of the actual system was purchased to test patches, anti-virus updates, and configuration changes. This simulator is connected to the Ovation Security Center as a separate network.

Perhaps the most striking consequence of the utility's cyber security program is that it now tries to eliminate use of programmable logic controllers (PLCs) on new generation projects, unless the OEM will not pro-

By the numbers

By any measure, the Ovation/WDPF Users' Group annual meeting—renamed the Ovation Users' Group at the completion of the 2011 event—is in a class by itself among such gatherings in the electric power industry. If you are an Ovation or WDPF user and have never attended the annual conference, join the group at www.ovationusers.com today (no cost) and pencil in the dates on your calendar for the 25th anniversary meeting (July 29-August 2, 2012). You won't be disappointed.

Three segments of the power and water industries are served by the Ovation Users' Group—fossil power, nuclear power, and water/wastewater. There were 80 technical breakout sessions at the four-day 2011 meeting and more than 100 speakers. One-third of the 265 users who attended were first-timers; 171 Emerson personnel were on hand to make sure all questions would be answered authoritatively.

Attendees can expect to take away one or more of the following from the meeting:

- Information on emerging technologies and control-system enhancements.
- How to improve plant performance and profitability.
- Industry trends and strategies to gain a competitive advantage.
- New ideas on how to extend the value of your control-system investment.

Social events aside, key features of each conference include these:

- **Exhibition.** There were more than two-dozen exhibits at the 2011 meeting—including ones manned by Emerson business associates Exele Information Systems Inc, GSE Systems Inc, Industrial Video & Control, Mitsubishi Power Systems Americas Inc, Schweitzer Engineering Laboratories Inc, and Westinghouse Electric Co. Emerson company participants included EIM, Fisher, AMS Suite software, Rosemount Analytical, Rosemount Inc. In addition, more than a dozen business lines from Emerson Process Management Power & Water Solutions were represented.
- **Top 10 product enhancement suggestions.** Provides an opportunity for all end users to participate in directing Emerson, Power & Water Solutions' product development plans for the coming year.
- **Professional development hours.** Many sessions are eligible for PDHs (one PDH unit for one contact hour of instruction or presentation), thereby helping you maintain professional certifications and grow within your company.

vide an equipment warranty without supplying its own controls.

Situational awareness

Dealing with alarms is only one aspect of a broader topic called situational awareness (SA), perhaps a more sophisticated term for the relationship of the human operator with the information bombarding him/her from the automation system. The new ingredient for SA is aggregating and presenting the predictive capabilities that are more and more being built into automation and control.

The definition of SA presented at the Ovation user group was "perceptions critical to decision makers in complex dynamic environments" which include comprehension of the meaning of what's happening as well as the projection of what's going to happen in the near future.

Comprehensive SA requires data from multiple sources and dimensions (Fig 5), including real-time, historical, and model reference—the last referring to simulation algorithms, state estimators, and system level predictive capabilities. The goals of the design are to (1) allow the operator to drill down to increasing levels of detail and (2) convert complexity into understanding through working and long-term memory mental models.

Projection is based on simulation algorithms and models. In tracking mode, the plant models update the "state" of the plant to reflect actual plant data, or data that has already been taken. In prediction mode, the simulation models are run closed loop to predict the state of important process variables into the future.

Operation is "synchronized" when tracking and prediction are integrated. For example, intelligent agents, which can be human operators (open loop) or controllers (closed loop), make control and monitoring decisions based on recognizing and correlating patterns in the data. According to Ovation engineers, SA affects the entire lifecycle of the control system, including the basic architecture and system design.

What's emerging

Multi-core processors and virtualization are the next "big things" in embedded computers, noted Emerson engineers. Essentially, what multi-core processes provide are larger system capacity (larger I/O count, more tags) and increased performance (faster loop times) for similar power budget (heat dissipation) and cost points.

Virtualization refers to the creation of a virtual machine that replicates what a physical machine might do. While virtualization has been prevalent in Windows-based workstation applications, the technique/technology has migrated to Ovation controllers, valve positioner modules, and Ethernet link controllers.

Based on surveys, customers are interested in seeing virtualization applied to off-line testing and development, operator training, on-line operator work stations, on-line application servers, and on-line historian servers.

Finally, everyone is talking about cloud computing and most of us are using it without knowing it. The "cloud" can be thought of as a natural progression in computing architecture beginning with mainframes, then client/server, then Web-based, and now cloud. The cloud (Fig 6) makes it even easier to create and deploy virtual machines, or applications, rather than installing applications directly onto host computers. In essence, it is similar to creating a Microsoft Word file at Google Docs rather than launching the Word application on your desktop and creating it there. CCJ

Gas-fired plants win big as wind energy confronts market forces

By Jason Makansi, Pearl Street Inc

Saying that wind energy is becoming victim to market forces may appear oxymoronic, because the industry is supported by state renewable portfolio standards (RPS), the federal production tax credit (PTC), the Federal Energy Regulatory Commission (FERC) new Order 1000, and various other loans and subsidies that flowed through the American Reinvestment and Recovery Act (ARRA) and other loan guarantee programs.

But having all of that support can't counter the price trends for natural gas, the lack of need for capacity additions, the difficulties in expanding transmission to connect wind facilities to load centers, the lack of a national carbon policy, and grid integration costs that more and more may become the economic burden of wind facilities rather than socialized through lack of transparency of these costs in consumer rates.

If this makes wind enthusiasts feel particularly vulnerable, it shouldn't. Virtually all other capacity options are being challenged by natural gas price trends reflecting the U.S. "shale gas revolution." Not only is gas likely to win most economic evaluations for new capacity, but gas-fired plants stand to reap big dividends from wind energy integration.

The headwinds confronting wind were driven home during the Electric Power Research Institute's (EPRI) media briefing on November 1, "Wind Power Costs, Integration, and R&D Challenges." Three reports were distributed as part of the briefing:

- "Impacts of Wind Generation Integration" (April 2011).
- "Wind Power: Issues and Opportunities for Advancing Technology, Expanding Renewable Generation, and Reducing Emissions" (July 2011).
- "Program on Technology Innovation: Integrated Technology Generation Options" (June 2011).

These reports, and others, are available at www.integrating-renewables.org/reports.

Wind is "out of the market" on an unsubsidized basis everywhere except the upper Midwest, according to EPRI officials, despite the 33% drop in capital costs since 2008. The market is driven by the RPS, but wind is not deployed at a market price. Capacity factors for wind energy facilities vary from 28% to 40%, leading to a factor of two difference in operating costs among facilities.

Costs for wind integration range from 0 to $5.63/MWh, based on EPRI's synthesis of evaluations from the US and Europe. Keep in mind that these costs reflect only the grid operating flexibility necessary to balance the variability and uncertainty of wind energy, not the cost to deliver wind energy to the grid.

The goal of advanced wind energy R&D is "grid parity with other resources," notes EPRI officials. Yet grid parity is a long way off. Assuming consistent support for the RD&D steps EPRI outlines, the earliest wind energy will be competitive without subsidies is 2030, and perhaps as late as 2050, based on EPRI's forecasts. The analysis in the support documents notes that this is a comparison of wind with other "non-emitting generation options." The key thrust of the EPRI briefing was to suggest that more aggressive wind energy RD&D will be necessary, especially if wind starts to lose some of the subsidies and mandates it has enjoyed over the last 20 years.

Many of these subsidies are being challenged in the political arena. And, almost every state RPS includes a caveat that RPS goals could be delayed or removed under poor economic conditions. Most of the country is currently suffering from a protracted economic malaise, which has caused electricity demand destruction and made new classes of voters skeptical about subsidizing one option over another.

The challenge for wind, or any other option, to compete against gas is starkly revealed in Tables 1 and 2, which show EPRI's forecasts for the levelized cost of electricity (LCOE) for several generation alternatives. Carbon cap and trade, or other national carbon policy or tax, is off the table politically for a while. And it's a pretty sure bet that no off-shore wind

Table 1: Representative cost and performance of generation technologies (2015)

All costs in constant Dec 2010 dollars	Nominal plant capacity, MW	Capacity factor, %	Book life[1], years	Heat rate, Btu/kWh	CO_2 emissions[2], metric tons/MWh	Total plant cost, $/kW	Total capital required[3], $/kW	FOM, $/kW-yr	VOM, $/MWh	Fuel price, $/million Btu	LCOE[4], $/MWh
Coal: PC[5]	750	80	40	8750	0.84	2000-2300	2400-2760	48	2	1.8-2.0	54-60
Coal: IGCC[5]	600	80	40	8940	0.86	2600-2850	3150-3450	74	2.3	1.8-2.0	68-73
Natural gas: NGCC[6]	550	80	30	6900	0.37	1060-1150	1275-1375	16	2.3	4-8	49-79
Nuclear	1400	90	40	10,000	-	3900-4400	5250-5900	110	1.7	0.4-0.8	76-87
Biomass: bubbling fluidized bed	100	85	40	12,900	0[7]	3500-4400	4000-5000	63	5	2-6	84-147
Wind: on-shore	100	28-40	20	—	—	2025-2700	2120-2825	35	—	—	75-138
Wind: off-shore	200	40	20	—	—	3100-4000	3250-4200	105	—	—	130-159
Solar: concentrating solar thermal	100-250	25-49	30	—	—	3300-5300	4050-6500	64-68	—	—	151-195
Solar: photovoltaic	10	15-28	20	—	—	3400-4600	3725-5050	50-65	—	—	242-455

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Table 2: Representative cost and performance of generation technologies (2025)

All costs in constant Dec 2010 dollars	Nominal plant capacity, MW	Capacity factor, %	Book life[1], years	Heat rate, Btu/kWh	CO_2 emissions[2], metric tons/MWh	Total plant cost, $/kW	Total capital required[3], $/kW	FOM, $/kW-yr	VOM, $/MWh	Fuel price, $/million Btu	LCOE[4], $/MWh
Coal: PC with carbon capture[5,8]	600	80	40	9840-11,800	0.09-0.11	3200-4100	3850-4920	79	3.8	1.8-2.0	87-105
Coal: IGCC with carbon capture[5,8]	500	80	40	9100-11,000	0.09-0.15	3100-3800	3750-4600	97	3.3	1.8-2.0	85-101
Natural gas: NGCC[6]	550	80	30	6320	0.34	1060-1150	1275-1375	16	2.3	4-8	47-74
Natural gas: NGCC with carbon capture[6,8]	450	80	30	7140-8000	0.04	1600-1900	1900-2250	30	6.5	4-8	68-109
Nuclear	1400	90	40	10,000	—	3800-4250	5100-5700	110	1.7	0.4-0.8	74-85
Biomass: bubbling fluidized bed	100	85	40	11,400	0[7]	3400-4250	3900-4850	63	5.0	2-6	80-136
Wind: on-shore	100	28-40	20	—	—	1960-2600	2050-2720	35	—	—	73-134
Wind: off-shore	200	40	20	—	—	2850-3650	3000-3825	105	—	—	122-147
Solar: concentrating solar thermal	100-250	26-58	30	—	—	3000-4800	3700-5900	62-68	—	—	116-173
Solar: photovoltaic	10	15-28	20	—	—	2900-3950	3175-4325	50-65	—	—	210-396

Abbreviations: PC=pulverized coal; IGCC=integrated gasification combined cycle; NGCC=natural-gas-fired combined cycle

1 Book life refers to the operating life of the plant

2 CO_2 emissions are for power generation only, not life cycle emissions

3 Total capital required is based on overnight capital costs plus estimated project/site-specific costs and owner's costs. Finite escalation (that is, beyond 2010) is not included. Does not include production tax credits, investment tax credits, loan guarantees, or other incentive programs

4 Levelized cost of electricity (LCOE) includes estimated capital costs, fuel costs, and VOM (variable O&M) and FOM (fixed O&M) costs. Financing rates are based on IOU financial assumptions. Since the LCOE is based on a constant dollar (December 2010) basis, no inflation/escalation for fuel, capital cost, and O&M is assumed. Does not include production tax credits, investment tax credits, loan guarantees, or other incentive programs, nor major capital refurbishments or decommissioning costs (except for nuclear, which includes a $1/MWh federal nuclear waste fund fee in the VOM)

5 Sulfur oxides/hydrogen sulfide, nitrogen oxides, particulate matter, and mercury emissions controls are included in the coal technology estimates

6 80% capacity factor for NGCC is assumed for comparison of all fossil technologies on potential as base-load generation technology options

7 Biomass emissions can vary significantly based on fuel source and life-cycle emission assumptions. Conventionally, the release of carbon from biogenic sources is assumed to be balanced by the uptake of carbon when the feedstock is grown, resulting in zero net CO_2 emissions over some period of time. However, if increased use of biomass energy results in a decline in global carbon stocks, a net positive release of carbon may occur

8 LCOE includes transportation and storage cost of $10/metric ton CO_2 which, on a per MWh basis, adds $3, $6, and $7 to NGCC, IGCC, and PC, respectively

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turbines will be operating, since none have yet to be permitted.

Therefore, the relevant comparison is a gas-fired combined cycle without carbon capture against on-shore wind. The top of the gas option's LCOE range is the bottom of the wind energy option LCOE. When you consider that on-shore wind, under the best conditions, is capable of a capacity factor only half that of a gas-fired plant, the overall cost of ownership is actually quite worse.

While R&D can lower the costs of wind energy, the EPRI team pointed out that the technologies wind competes against don't stand still, that there are advances, for example, in gas turbine and shale gas extraction technologies coming in parallel (Table 3). While it is true that the fuel is "free" with wind energy, the strength of the resource varies dramatically depending on location.

Anyone familiar with recent history in the power industry knows that gas prices can escalate in a relatively little time. However, what is not widely known is that the delivered price of natural gas is now "independent of geography," according to the EPRI documentation, thanks to an "unprecedented expansion of the transmission pipeline network."

In the short term, wind energy integration is a "win" for gas. EPRI's modeling work shows that large-scale wind deployment will be accompanied by substantial additions of gas-fired capacity both to meet ramping requirements and hold reliability, increasing delivered COE. This is already playing out in California. The state is pursuing a 33% RPS by 2020, and the current governor has stated he considers that a "floor" not a "ceiling."

One utility in the southern part of the state has stated in public documents that it is purchasing $750 million of gas-fired assets. And while new, flexible gas turbines are being made available for the rapid grid responses induced by wind variability, a parallel challenge is the impact on gas delivery to the powerplant. Access "Integrating Renewables into the Generation Mix," at www.integrating-renewables.org.

Moving energy to market. Wind integration costs and ecological impacts are important—but the lack of transmission probably holds up more wind projects than anything else, except for the low price of natural gas. EPRI notes that transmission is particularly challenging: "From planning to permitting, from capital cost estimation to cost allocation, there is no clear indication how and whether sufficient transmission will be constructed to tap our vast, remote domestic wind resources."

In essence, then, the economics of gas-fired generation benefits from

Table 3: Technology status of the gas-turbine-based combined cycle

	State-of-the-art frame engines	State-of-the-art aero engines	Advanced frame turbines operating on natural gas
Major trends	■ 2500+F firing temperature ■ Some aero features ■ Dry low-NO_X combustor ■ External cooling of cooling air ■ Higher capacity and pressure ratio	■ 2550F firing temperature (LMS100) ■ Industrial cogeneration ■ Quick delivery of prepackaged units ■ Offsite overhauls ■ Dry low-NO_X combustor	■ 2600F firing temperature ■ Steam cooling system ■ 3-D compressor airfoils ■ Improved air cooling of turbine blades ■ Advanced thermal barrier coatings, seals
Changes to watch for	■ Modest upgrades to provide low-cost alternative to advanced turbines	■ Uprating of existing units ■ Higher availability because of replacement units ■ Long-term performance and reliability of LMS100	■ More aero features ■ Catalytic combustion ■ Improvements and higher temperatures in HRSGs (new alloys for pressure parts)
Market restructuring and deregulation	■ Favors NGCC over traditional coal/nuclear for new base-load because of better short-term economics or concern over global warming (pc-fired plants)	■ Cogeneration improves economics and assures much higher efficiency than traditional central powerplant	
Key issues	■ Advantage of low capital cost and high combined cycle efficiency	■ Advantage of industrial cogeneration at high power/heat/ratios ■ Quick overhaul turnaround	■ Price of natural gas ■ Possible future inroads for IGCC application
Key market and business indicators	■ Growth in peaking and cycling power generation ■ Impact on capital cost and plant performance if CO_2 removal is mandated ■ High output with high efficiency in cycling duty service	■ Growth in industrial cogeneration ■ Impact on capital cost and plant performance if CO_2 removal is mandated ■ High output with high efficiency in cycling duty service ■ Provide grid stability for integration of variable, renewable generation	■ Rise in gas prices may justify investment in more engine R&D ■ Impact on capital cost and plant performance if CO_2 removal is mandated

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an existing gas transmission infrastructure while the economics of wind generation is constrained by the lack of electricity transmission infrastructure. What's more, note EPRI officials, any transmission lines dedicated to remote wind facilities and built to nameplate capacity will be under-utilized because of low capacity factors, or large curtailments will sometimes occur.

Although wind energy is "emissions-free," it comes with its own environmental constraints and unintended impacts. EPRI officials noted that these constraints are beginning to affect economic viability of projects in some regions.

One of the unintended environmental impacts mentioned is the endangered Indiana bat, which is holding up permits in that state. Protecting bats and other migratory avian species may require facilities to shut down at certain times of the year, further impairing already fragile economics. As if to prove once again that Mother Nature offers no free lunch, most bat fatalities associated with wind turbines occur in late summer and early autumn, during the hot weather when electricity is needed most to meet air conditioning and cooling demand. In an attempt to avoid wholesale shutdowns of wind facilities when operating economics are best, EPRI's R&D program includes a bat detection and automatic turbine shutdown system.

This isn't to diminish other positive conclusions from EPRI's work. Example: Although wind farms have substantial land requirements, wind is among the most efficient energy sources from a land use perspective, when all factors are taken into account. Also, wind turbines appear to have minor and localized effects on habitats and species compared with other electricity supply options. Overall, EPRI concludes that "land-based wind resources are sufficient to meet more than 50% of future US electricity needs at a wholesale COE of about $80-90/MWh."

Role for storage? A compressed air energy storage (CAES) facility is a modified gas-fired power station. The electricity-fed motor drives a compressor to store high-pressure air, usually in an underground cavern. The machine essentially operates in reverse, along with the addition of natural gas, to generate electricity when attractive to do so. Could this technology help integrate wind energy into the grid?

"Yes," according to EPRI's analyses, as long as decisions regarding the operation of the storage facility "are based on the aggregated balancing needs of the entire bulk power system for that region." As a facility dedicated to wind back-up, the answer is "no," at least up to 10-20% wind penetration. In this regard, CAES with underground cavern storage is a vital technology for grid operation and wind integration because it consistently pencils out as the most cost-effective storage option available, according to an earlier EPRI white paper on energy storage, released last year. CCJ

Jason Makansi is president, Pearl Street Inc, a St. Louis-based energy consultancy. A prolific author, respected industry thought leader, and seasoned communicator, Makansi has been analyzing the technological, business, and regulatory issues in electricity production and delivery for nearly 30 years. He specializes in conducting technology deployment programs and projects for clients. Makansi has three books to his credit, and has appeared on CNBC and the Financial News Network and been interviewed on NPR. You can contact him at jmakansi@pearlstreetinc.com.

Jurassic turbine keeps on ticking

By Rodger O Andersen, DRS Power Technology Inc

Back in the Jurassic era, when your elementary school teacher used a mimeograph machine (and the scent presaged your college days), when a guy in a swim suit jumped off a cliff in Hawaii hawking a Timex watch on your rabbit-eared television, a Dresser Clark gas turbine came into existence. Well, okay, it was 1960 but in machine time, that's a dinosaur of a turbine. Yet the owner of that turbine, the epitome of low tech today, still extracts huge value from it, deploying it as a peak shaving unit and capacity resource.

Let's examine the fossil record

The original machine served admirably at a naval test facility for a few years. After its honorable discharge, with plenty of value to spare, Northwestern Wisconsin Electric, a small utility, bought it and repurposed it for peaking service in 1981 (Sidebar 1). In the late 1990s, the unit suffered from airfoil damage and a failed expansion joint (Fig 1).

The blade issue wasn't too big a deal but the utility was ready to scrap the unit because replacing the expansion joint would require a complete disassembly of the engine. Just before the machine was headed for the bone yard, the utility accepted an alternative solution, which proved successful. In late 2002, the unit was put back in peaking service.

No one would dare suggest that this was an agile dinosaur. Even back in the day, it was probably related to brontosaurus, not triceratops. The Dresser Clark model 302 delivers 7 MW with a firing temperature of about 1300F and a pressure ratio of about four. The torso is a 15-stage axial compressor, the legs

1. Vintage 1950s design turbine delivers peak shaving power after indicated work scope was undertaken

2. Combustion system has eight burners. Combustion chamber is 4 ft in diameter

3. Hopper feeds solid cleaning agents (rice hulls, walnut shells) into compressor. Emergency stop lever closes the inlet damper valve to starve the GT of air flow

a two-stage HP turbine running at 4600-4700 rpm. The power turbine, also two stages, turns at 3600 rpm.

The large reverse-flow combustion chamber (Fig 2) is supported directly over the compressor case. Liquid fuel feeds the hungry beast through eight burner nozzles. The machine even sports a hopper and valve for injecting rice or ground up walnut shells for compressor cleaning. When the machine needs to quit running, an emergency stop lever is pulled to close dampers in the inlet duct and starve the machine of air (Fig 3).

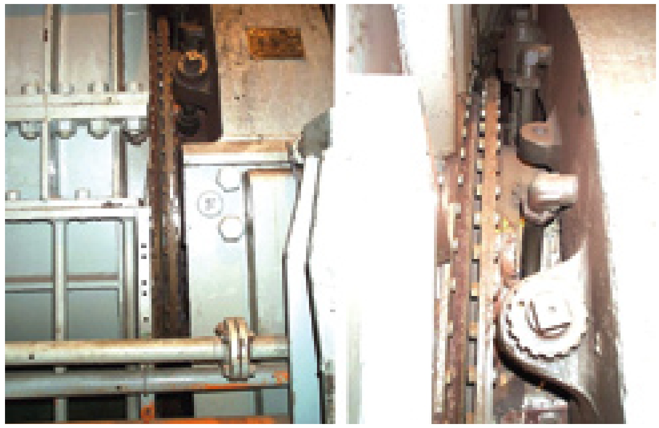
Like most dinosaurs, this one requires a lot of surrounding real estate. Skid mounting of the lube oil system wasn't common practice in Jurassic times. This machine has an oil system that takes up 900 ft^2 (Fig 4). The machine itself is mounted on a large barge-shaped steel base frame.

Takes a licking

In its reincarnation, the DC 302 held its turf for many years, giving 50 to 100 hours of operation annually to the utility. But dinosaurs get wounded, too, and this one was almost left for dead. In August 1999, combustion problems resulted in damage to the turbine blades and vanes. After repairs were made, some compressor blades were damaged but the machine still shivered with vibration. Finally, by April 2001, it appeared that the machine was back in good health. Just as it was reaching full power, the downstream side expansion joint between the combustor hot casing and the turbine case blew out (Fig 5).

This wasn't just a hole in the skin that could be stitched up. The expansion joint is a 360-deg, 7-ft-diam ring that would require a complete disassembly of the unit to replace. An

4. Lube oil system takes up some serious floor space



5. Expansion joint blew out after a compressor blade repair

1. NW Electric: All in the family

Talk about fossils, there aren't many utilities with a family lineage. Mark Dahlberg, president, NW Electric, is the grandson of the founder, Aaron Dahlberg. At the age of 25, Aaron built a dam near Round Lake to power custom sawing, planing, and feed grinding. Later this hydroelectric facility was outfitted with an alternating current generator, establishing the beginning of electricity service in the region.

In 1943, NW Electric acquired neighboring Polk-Burnett Light & Power to create the utility's service territory that is largely the same today. The electricity enterprise started by Aaron in 1907 today has 14,000 customers and 140 miles of 69-kV line, and is owned by 51 shareholders in the area.

With the exception of the peaker described here, NW Electric is a distribution utility, purchasing 93% of its electricity from Xcel Energy and 7% from a hydroelectric facility owned by Dairyland Electric Cooperative. The peaking unit typically operates around eight hours when fired up, although it wasn't called upon to do so in 2008 and 2009.

According to Dahlberg, the original Dresser Clark unit ran only about 1000 hours as part of an experimental ship tested by the Navy. NW Electric bought it from O'Brien Machinery Co, and received approval from the state Public Utility Commission to install it in 1981. When asked how much the machine cost the utility, Dahlberg pulled out the receipt right there and said, "Here it is, $1,072,000!" Now that sounds like a family-run business, even if family extends to the community.

6. Overlay strap avoided a costly complete disassembly and replacement joint

8. Blue smoke started spewing from the bearing tunnel although the expansion-joint repair was successful

7. Vibration problems were corrected on the inter-stage seal of the second-stage turbine. **A** shows first-stage nozzle diaphragm. Note that there is no horizontal joint; all turbine stationary parts are full 360-deg rings. Rotor disk bolts are in **B.** Bolt elongation was calculated to achieve a stress of 40 kpsi. Bladed first-stage turbine disk is in **C.** Turbine rotor nuts and second-stage disk are shown in **D.** Drop dimensions to the end of the bolts were measured to confirm elongation of each bolt; results agreed with the calculated elongation from the number of nut rotations on the bolt threads

2. A bad meal

The fossil record occasionally reveals what these Jurassic creatures eat. Some small prey inadvertently ingested by this machine caused some real indigestion.

To solve the mystery of the blue smoke, the utility first inspected the unit. The borescope technician found only one crack but that was associated with negative pressure, not positive. The cooling-air pipe to the load tunnel bearings was disassembled and found to be clear. Oil soaked insulation was scraped out of the load tunnel. Then manometers and pressure gages were installed to check pressure at key locations. Once the unit was fired up, it was clear that the smoke was coming from the compressor/turbine tunnel, not the load tunnel between the generator and the exhaust end.

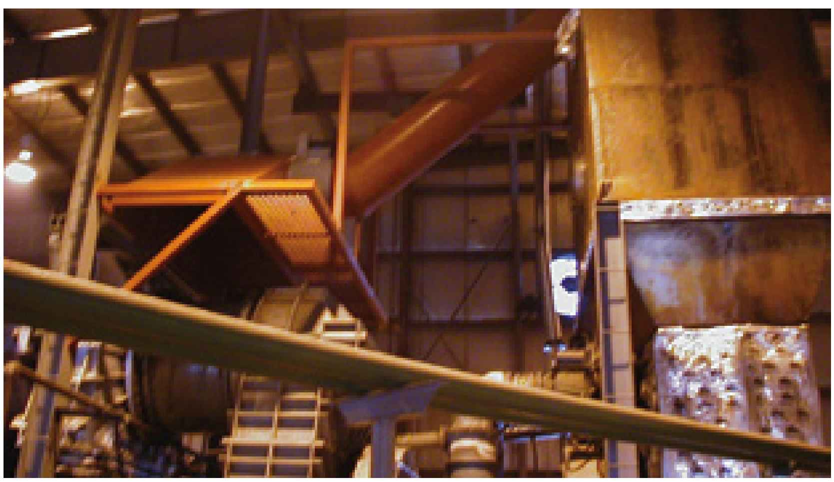
The only abnormal pressure reading was at the bearing-seal vent line. It exhibited a positive pressure of 2 in. H_2O but should have had a negative pressure because of the venturi it was connected to. Positive pressure would cause bearing oil leakage into hot gas areas. After the test, the venturi was removed and the remains of three dead birds (Fig A) were found inside!

Some of the smoke was eliminated by tightening the casing bolts, but damaged or worn shaft seals were allowing hot blow-by air to reach the bearing oil.

Most of the remaining smoke was eliminated by installing a collection hood (Fig B), induced-draft blower over the bearing tunnel, and plenum discharging into the gas turbine exhaust stack, where it is oxidized and released.

A. Dead birds were found in the "belly of the beast," in the venturi piping (above)

B. Collection hood, ID fan, and plenum to the exhaust stack removes smoke from the building (right)



18-in. section of the thin split tube had ruptured and the wound was not accessible for weld repair. The cost was pegged at $300,000 and the owners suspected other major problems with the engine. Only an in-situ repair for very low cost could be tolerated; otherwise this dinosaur was on the road to extinction.

Fortunately, a second opinion revealed a practical, far less expensive alternative. The combustion hot casing is supported by flex rods that allow expansion in all directions. Thermal expansion calculations showed that a single joint was capable of handling the total expansion of the hot casing relative to the turbine casing. The damaged part of the joint could be abandoned in place by covering it over with a continuous strap (Fig 6) seal welded to both the hot casing and the turbine casing.

The specific steps in the surgery were the following:

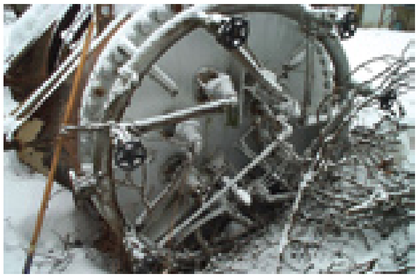
- Remove the 192 bolts that held the expansion joint between the two casings.
- Cut sections of 0.125-in.-thick steel strips, bent to the correct curvature.
- Seam weld the strips to the expansion joint, then butt weld the strips to each other to form a continuous overlay.
- Fit the straps under the bolts and nuts on the flange that mates with the combustion hot casing and over the bolts and nuts on the flange that mates with the turbine casing.
- Reinsert the 192 bolts and tighten.

During the same period, the turbine rotor and nozzle casings were disassembled to correct rub-related rotor vibration (Fig 7). The interstage seal mounted on the second stage turbine nozzle was rubbing on the first and second stage turbine discs. Seal surfaces were hand ground to increase radial clearances. The entire machine was then reassembled.

Roaring back to life

Initial startup for the reconditioned machine occurred in late November 2002, nearly three and a half years after the unit was forced out of service. It ran for one hour synchronized to the grid and half that time it delivered 6.1 MW.

Rotor vibration was acceptable and the soundness of the expansion joint solution was demonstrated. But fuel system pressure swings caused the turbine to trip and there was still a problem in the bearing tunnel. After the engine warmed up, a blue cloud of smoke (Fig 8) would



9. Spare parts are stored outside. Note the eight gas fuel nozzles with manifold mounted on the combustor cover

emanate from the tunnel that would eventually fill the turbine building (Sidebar 2).

As noted earlier, this dinosaur isn't winning any Darwin awards for efficiency and agility. Its heat rate is nearly 20,000 Btu/kWh, so it sucks up fuel. But it earns its keep even in hibernation because the owner receives capacity payments for having the megawatts available.

But the legend around this machine doesn't end here. Distillate fuel is expensive and natural gas isn't these days. Previously, the utility had purchased a retired high-pressure unit for spare parts (Fig 9). While the casing and expansion joints of the spare had slightly different dimensions, it turned out that its gas fuel manifold and cover would fit the reconditioned unit.

The owner verified that the nozzles could handle the flow at the delivery pressure of the gas supplier in the area, added control valves for the gaseous fuel, and replaced the liquid-fuel manifold with the gas-fuel manifold from the spare. Today, this fossil of a turbine can operate on the less expensive fossil fuel or fire up on the original fuel. CCJ

Rodger O Anderson is responsible for gas-turbine design and upgrade initiatives at DRS Power Technology Inc, which is part of the Finmeccanica family. Anderson spent nearly 30 at General Electric Co in various high-profile GT engineering positions—including lead technical designer for the 7F gas path. Anderson also was Director of Engineering for Hartford Steam Boiler Inspection & Insurance Co for eight years, during which time he participated in the investigation of more than 200 gas-turbine accidents. He joined Power Technology 10 years ago, before its acquisition by DRS.

Fleet leader

1. Harry Allen's 2 x 1 combined cycle, sited in a difficult desert environment about 35 miles north of Las Vegas, is the flagship of NV Energy's fleet

As NV Energy Inc's President/CEO Michael W Yackira dedicated the 2 × 1 7FA-powered combined cycle at Harry Allen Generating Station last May, VP Generation Kevin Geraghty told the editors he believed the heavily instrumented plant would prove itself as the utility's top performer.

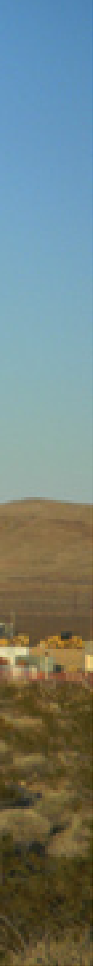
Late in the year, Regional Director Steve Page and Assistant Regional Director Brian Paetzold sat down with the editors and said Geraghty was right: Harry Allen was the company's best running plant "right out of the gate" and the best performing new plant in the company's history.

At the six-month mark, the GADS forced-outage rate (FOR) was an enviable 4.57% and GADS equivalent availability factor (EAF) was 82.88%. The latter number would have been more than 92% had a rodent not gained access to an ineffectively sealed exciter cabinet where it chewed the load commutated inverter (LCI) to failure. GADS is the North American Electric Reliability Corp's Generating Availability Data System.

Plant executives said The Shaw Group, the EPC contractor, contributed significantly to Harry Allen's success. In their opinion, Shaw's conservative design approach will assure top performance over the long term.

The air-cooled plant operates at a nominal heat rate of 7100 Btu/kWh, the best in NV Energy's fleet. It can ramp at 28 MW/min, contributing to reduced demand for spinning reserve. A warranty inspection is planned for March and the first combustion

2. D11 steam turbine is a two-case unit with a common HP/IP section and a double-flow LP. Exhaust configuration is a standard down arrangement exhausting to the steam duct for distribution to the ACC headers



inspection (CI) at 12,000 hours—near year-end 2012.

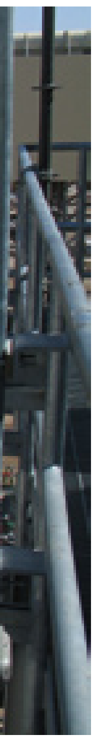
Lessons learned. Geraghty and New Generation Executive Andy McNeil, the person responsible for building the plant, were committed to applying lessons learned and best practices from previous projects to assure a high level of success. One of Paetzold's responsibilities was to make sure operational and maintenance challenges experienced in the fleet would not resurface at Harry Allen.

McNeil said his construction team had gained valuable experience in building and commissioning over the last six years nearly 3000 MW of new gas-turbine-powered capacity, and that was brought to bear on the Harry Allen project. To build on this know-how, Project Manager Nitin Luhar, who works for McNeil, headed up the cataloging of best practices identified with the Harry Allen effort, with help from owner's engineer Zachry Engineering Inc.

Luhar told the editors that NV Energy has a file—a living document if you will—containing more than 200 best practices for combined-cycle design and construction. Some are relatively simple and may even seem insignificant, he said. Luhar offered the use of quality fasteners and pipe coatings as examples of some "small" things incorporated into the spec that have a positive impact on job quality.

Having a tighter spec also saves time by not having to "reinvent the wheel" and by not making the same errors multiple times. One example is the handling of demin water during steam blows to minimize leaks. This is important because spills of demin water on the desert floor are permit violations that can initiate "stop work" orders.

The editors asked Luhar what stood out in his mind about this project, something he'd like to experience on all construction projects. His reply: An outstanding level of communication between Shaw and NV Energy personnel. Constructive attitudes prevailed throughout the project. "We never had difficulty working things out," he said. The plant was completed on time and within budget, McNeil added. Robert Follett was Shaw's project director when the "keys" were handed to the utility. Robert Burke headed the team from owner's engineer Zachry Engineering Inc.



Interesting to note is that NV Energy, which relied on the experience of other plants in its fleet to assure success at Harry Allen, now is tapping Allen's experience to help plan upgrades at the mature plants to increase their availability and efficiency, and improve overall performance.

A key project goal was to build a cost-effective, efficient, and reliable plant capable of competing against merchant generators. This meant avoiding the gold-plating sometimes associated with utility-owned power projects.

The specifications for Harry Allen followed the baseline design of the nearby Chuck Lenzie Generating Station, in large measure to maintain consistency in operations, maintenance, and spare-parts inventory between the two plants. The basic layout calls for generous centerline spacing between the gas turbines to facilitate O&M. The steam turbine is placed between the two unit centerlines but beyond the HRSG stacks.

Design features

Paetzold was assigned to the project soon after site work began. He had managed the Lenzie facility for a period and was intimately familiar with GE 7FAs and their idiosyncrasies. Harry Allen is powered by two 7FA.03/

DLN2.6 gas turbines (Fig 1). Plus, Paetzold knew about the 7FA and D11 steamer experiences of others through participation in industry organizations such as the 7F Users Group.

Regional Director Steve Page, who is responsible for the Arrow Canyon Complex (Harry Allen, Lenzie, and Silverhawk Generating Station), and Paetzold reviewed some of the new plant's features, beginning with automation. Total staff at Harry Allen is 19, with two operators on a shift—one in the control room, the other outside.

When you're running a plant designed for 150 starts per year with two operators, Paetzold said, NV Energy's experience suggests automating to the maximum extent possible. For example, he asked rhetorically, why hand an operator a startup procedure when you can program all the steps into the control system and assure that the optimal program is run every time? Automation takes operator variability out of the equation, he added.

To achieve the high degree of automation employed at Harry Allen, virtually all field data and control functions flow through the Ovation™ distributed control system provided by Emerson Process Management Power and Water Solutions, Pittsburgh. The only PLCs in the plant are those for the burner management system (HRSG duct firing), the static frequency converter used to start the gas turbines, and the filter press in the wastewater treatment system.

Arrow Canyon management team. Front row (l to r): David Hall, engineering manager; Fatima Bouzidi, senior engineer; Deborah Henninger, senior staff consultant; Brian Paetzold, assistant regional director; Shane Pritchard, O&M manager; Steve Page, regional director. Back row: Forrest Hawman, O&M manager; Sean Schmitt, operations supervisor; Clark McCarrell, senior engineer; Kent Steadman, staff business consultant; William Slade, project manager; Ronald McCallum O&M manager. Camera shy: Joseph Gaither, staff engineer (on reserve military assignment in Afghanistan)

Enabling a high degree of automation is time-consuming, Page offered. But when this work is complete, your plant has a predictable behavior and can be managed more effectively. Paetzold provided some metrics: Roughly 2500 I/O points are brought into Ovation from each of the Mark VIe gas-turbine control systems and another 3000 or so from the steam turbine; water treatment and BOP add 13,000.

Shaw and Emerson did most of the work associated with configuring the DCS for automation. The effort required to capture operating data in OSIsoft LLC's PI historian was not included in the EPC contractor's scope. Harry Allen is the most advanced plant in the NV Energy fleet regarding data capture.

Data storage is cheap, Paetzold noted, "so we're collecting all the information we can. We're not sure exactly what we might need for analysis purposes in the future." Some of the data captured in the near term certainly will help support Geraghty's efforts to determine future manpower and training requirements, etc.

At this point, no decision has been made regarding the use of predictive analytics for supporting O&M decision-making.

Best practices. The discussion turned to best practices adopted for Harry Allen. Page began with safety. He said a robust system of permanent platforms and ladders was installed to facilitate safe access to equipment by the one roving operator on duty after the day shift.

Paetzold added that participation in 7F User Group meetings enabled better decision-making on gas-turbine package features. The Harry Allen 7FAs are equipped with the latest R0 blade correction and with bellows-type seals at the intersections of cross-fire tubes and combustors. The agreement with GE stipulated that the requirements of any Technical Information Letter issued up until "substantial completion" had to be implemented. Some steamer upgrades were made as well.

NV Energy purchased major equipment directly—including the gas and steam turbine/generators and HRSGs. The gas turbines are the same models installed at Tracy and Lenzie and the steamer is similar to Tracy's. Having several of the same machines reduces fleet spare-parts inventory, facilitates overhauls and personnel deployment, etc—thereby contributing significantly to the goal of minimum life-cycle cost.

The owner approval process for the layout of high-energy piping systems was changed based on experience to permit detailed review of stress-analysis calculations before the EPC contractor releases drawings for fabrication. This process helped avoid cost overruns associated with correcting piping and fabrication.

ACCs. NV Energy, thought to have more air-cooled condenser cells than any other utility, applied some in-house lessons learned to the heat-rejection system. One was locating condensate pumps out from under the fan deck to facilitate crane access. Another was specification of new type of vibration shutoff device that can be desensitized on startup and load changes to prevent fan trips.

Paetzold said special attention was given to fan-blade selection and handling. Harry Allen's 36 cells have 36-ft-diam, fixed-pitch fiberglass blades. Plant performance guarantees can be met with one fan out of operation. Blades were handled with "kid gloves" to avoid "dings" that could initiate an in-service failure. Shaw ordered two spare sets of blades in case damage occurred during shipping or installation.

Evaporative coolers were selected for the gas turbines because of their better economics and reduced water use compared to chillers. Paetzold acknowledged that chillers have capacity and heat-rate benefits, but questions remain in the minds of NV Energy engineers regarding life-cycle cost. Also, the site air permit didn't allow the additional PM10 that would have come from the proposed wet towers needed for the chillers.

3. Heat-recovery steam generator is a triple-pressure natural-circulation unit equipped with gas-only supplementary firing to support summer peak demand

Heat rejection from closed cooling water is handled by a combination fin-fan/wet surface air cooler system as it is at both Lenzie and the Frank A Tracy Generating Station.

The plant is designed to produce 484 MW on a 112F day with 11% humidity. Output is restricted by permit limits on heat input to the duct burners as well as to the gas turbines. It can produce up to 550 MW with duct burners and evap coolers in service when ambient conditions are favorable. No fired boiler is permitted onsite, imposing operating constraints.

The D-11 steam turbine selected for Harry Allen is similar to the machines installed on the two Lenzie combined cycles: combined HP/IP casing with a double-flow LP section (30 in. last-stage blades) and configured for down exhaust. Generators are hydrogen-cooled.

HRSGs. The heat-recovery steam generators are traditional natural-circulation, triple-pressure horizontal units equipped with gas-only supplementary firing systems to support summer peak-load demand. Steam conditions at full fire are 1900 psig/1050F/1050F. Vogt Power International Inc's SMART-box design was selected to simplify construction. It modularizes the harps in groups to reduce onsite handling. Oxidation catalyst and the SCR are designed to meet the permit limits of 2 ppm CO and 2 ppm NO_x.

HRSGs feature a "double block and bleed" arrangement to permit operation in a 1 × 1 configuration if a boiler must be removed from service. The value of this capability was learned at Silverhawk when the transition-duct liner cracked on one of its boilers and insulation was sucked out, blinding downstream finned-tube heat-transfer surface. The entire plant had to be shut down to complete repairs and cleaning.

Water. The primary source of makeup is Harvey Well, located about 3.5 miles from the plant. Nonpotable water is withdrawn and routed through a two-stage reverse-osmosis (RO) system. Permeate from the first stage is used as makeup for the gas-turbine evap coolers; second-stage permeate is polished in mixed-bed demineralizers for steam-cycle makeup. Reject liquids are routed to one of two 2.5-acre onsite evap ponds; no liquids are discharged from the plant. Cake recovered from Harry Allen's filter press is sent offsite for disposal.

Early operations

The first several months of operation were relatively free of hiccups, Page and Paetzold told the editors. Obvious from the foregoing, no luck was involved. Long hours and focus on the tasks at hand paid dividends. You could read the disappointment on Paetzold's face when he talked about the only significant operational issue encountered: A problem with the butterfly-type balancing valve on one unit which forced operators to cycle a gas turbine 28 times in July.

But the ever-positive Paetzold still salvaged some good from the experience. The cycling was excellent training, he said. And it can help uncover possible problems you wouldn't normally find so early in the life of the plant. That wasn't the case at Harry Allen, however. It's a sound plant that just happened to get a lemon of a valve.

Automatic start-ups are a way of life at Harry Allen. With a total staff of 19, automation helps minimize operator stress and assure, to the degree possible, consistent starts. The plant is designed for 10 cold starts annually. Paetzold stressed to the editors that automatic operation does not mean that the CRO pushes a button and sits down. He or she must monitor carefully the startup process. NV Energy trains its operators on how to follow the startup and what parameters are most important to track and what excursions from the norms mean.

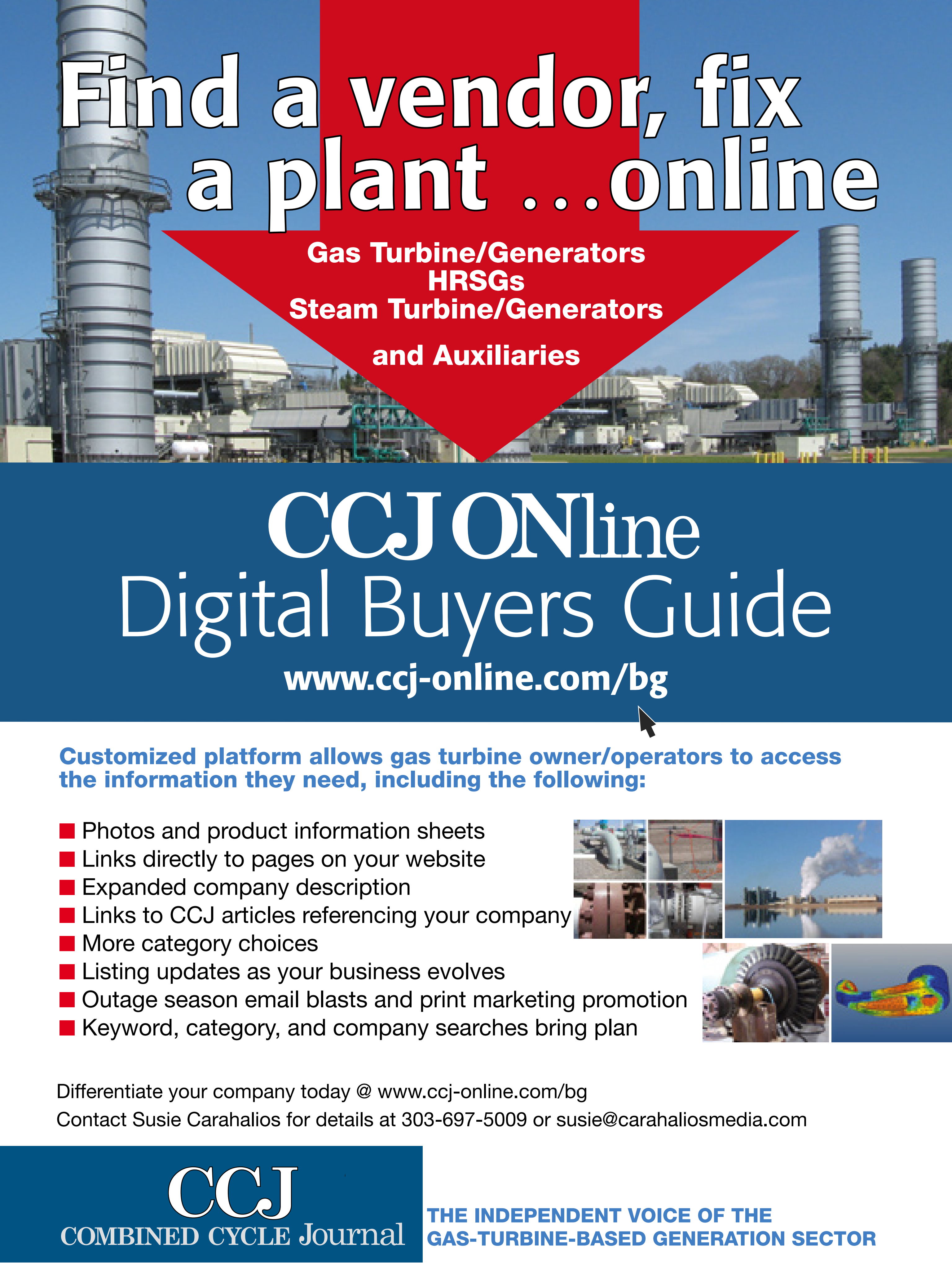
On an auto cold start, the boiler temperature ramp is 6.5 deg F/min and the sky vent is opened to achieve this. HRSG drain valves close automatically when 50 deg F of superheat is achieved.

Paetzold believes that the operator should close the gas-turbine breaker. After that happens, the turbine ramps to about 30 MW and holds until the IP feedwater temperature increases and brings the fuel-gas temperature leaving the performance heater to 310F. This takes about 45 min from the time the start is initiated, including a 15-min purge cycle.

Paetzold said that the steam seals on the steam turbine, the steam jet hogger for the ACC, and the gland steam exhauster are all on manual at this point, but there are plans for automating those procedures. Vacuum is achieved in about an hour and three-quarters. The operator then hits the button for an auto start which introduces reheat steam to the turbine. The HRSG setpoint is 85 psig at this time.

The steamer rolls and is synched manually on hot-reheat steam in about 10 min. The auto-start program transfers the turbine from reverse- to forward-flow operation on main steam and the unit is ramped to the load required.

The combined cycle often is transferred from 2 × 1 to 1 × 1 operation in the evening. When the gas turbine that has had the evening off is started the next morning, automation assures that HP header steam is within 25 psig/50 deg F of the steam for the operating unit before blending can begin. Automated blending is viewed as a positive means for preventing steam-system damage. CCJ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The dollars and sense of clean boiler tubes

Fouled finned-tube bundles in heat-recovery steam generators (HRSGs) can penalize your bottom line by hundreds of thousands of dollars on an annual basis, so it makes good sense to call in a qualified cleaning contractor—periodically (every year or two) or when pressure drop reaches what you decide is the "action-required" level.

According to Keith Boye of Precision Iceblast Corp (PIC), Wallace, Mich, every additional one-half inch (water column) of pressure drop through a typical F-class HRSG reduces your bottom line by about $100,000 per annum—depending on the price of fuel. There are no guarantees on how much a given cleaning will reduce your backpressure, but a rule of thumb is that a proper cleaning can recover half of the increase in pressure drop over the as-designed value.

An informal poll by the editors of users attending a recent industry meeting revealed that owner/operators were most likely to contract for cleaning when the pressure drop reaches about 3 in. H_2O above the as-new delta p. Payback on the investment should be three or four months at that point, they said, and typically acceptable to management.

The users generally agreed that corrosion products are relatively easy to remove from finned-tube panels, provided there's sufficient access space. By comparison, ammonia salts are difficult. The biggest challenges typically are found at plants not regulated on slip, where there may be a temptation to overfeed ammonia as a way to assure that NO_x emissions are maintained within permit limits. Plants burning gas with above-average levels of sulfur also run the risk of severe fouling.

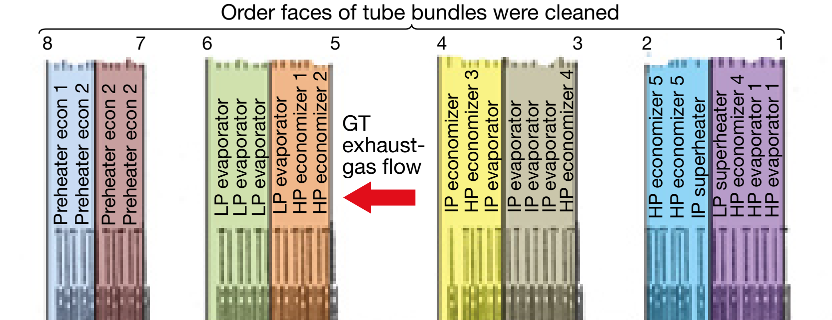
What cleaning medium? Contractors often rely on dry ice to remove deposits, sometimes high-pressure air, water, or grit blasting. A few plants have installed sonic horns to extend cleaning intervals, but they have not be successful in all cases. Several users warned against the use of water because it can turn otherwise manageable deposits into "concrete." Plus, water can contribute to corrosion of the HRSG floor, damage insulation, and shorten the lives of penetration seals.

Identifying the proper cleaning medium for your plant requires some research. Two variables particularly important to decision-making are foulant tenacity and the extent of fouling, Patrick Walker of HRST Inc, Eden Prairie, Minn, told the editors. You want to know how tough it is to remove and how deep the fouling penetrates each heat-transfer section. Then you can develop a procedure for its removal and an operating plan that would slow the deposition rate. A recommended first step is foulant characterization.

Not all foulants are created equal, Walker reminded. A thorough gas-side inspection and pressure-drop evaluation are an important part of your research. Comparing the latter to the delta p after cleaning will put hard numbers on the value of "clean" tubes. A before/after analysis also will help you predict the optimal time for the next cleaning.

Like foulants, not all cleaning contractors are created equal. There is some technology and engineering, in addition to fouling science, that you should know about before selecting a contractor (sidebar). For example, tube spreaders—so-called alignment bars—developed and patented by HRST enable deep penetration of cleaning wands into a tube bundle to access as much heat-transfer surface as possible. Tube spreading is not for amateurs. You need boiler design experience to calculate tube stresses associated with spreading. Get too aggressive opening up cleaning lanes and you can have real problems.

HRST also designs its own compressed-air nozzles to maximize cleaning effectiveness. It is not

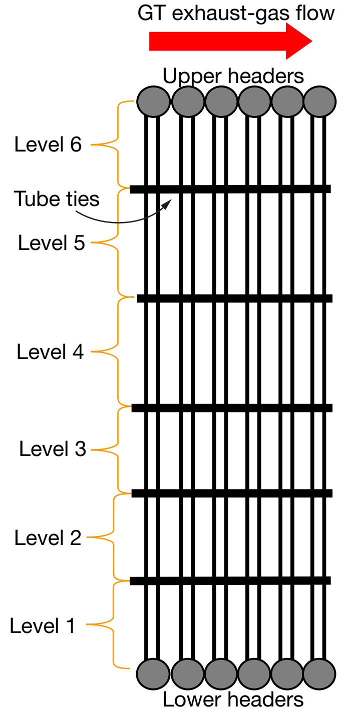


1. Tube bundles with the eight coolest faces in this HRSG were scheduled for cleaning using both dry ice and air, in sequence. Note the order of cleaning in the direction of exhaust-gas flow. Upstream face of HP evaporator 1 was cleaned first, the downstream face of HP economizer 5, was second, and so on

unusual for the company to customize cleaning heads to accommodate a boiler's idiosyncrasies.

A team approach to cleaning may beget best results, agreed Boye and Walker. When their companies work together, PIC brings to the table the cleaning know-how, HRST the engineered solutions. For simple jobs involving shallow tube banks—that is, four tube rows deep or less—most traditional "surface blasting" methods provide favorable results, unless the foulant is particularly tenacious. Walker described surface blasting as a cleaning method where the lance doesn't penetrate the "surface" or plane of the tube field. What you can see, you should be able to clean, Walker said.

In tube banks that are deep or have very close tube spacing, it is important to have tools to assure success—like those described above.



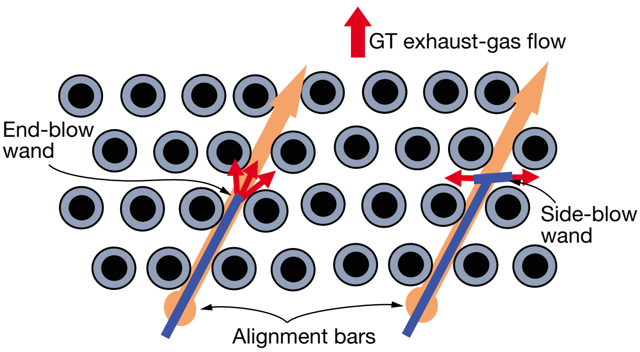
2. F-class HRSG had six cleaning levels separated by tube ties

A step-by-step plan is important for achieving top results. The information required to develop a plan might come from photos taken by HRST during a recent unit inspection. If those are not available, PIC will do a gas-side walkdown to determine the degree of fouling, to decide where spreading is necessary, etc. HRST gets design details from boiler drawings to customize cleaning heads and provide input to procedure development.

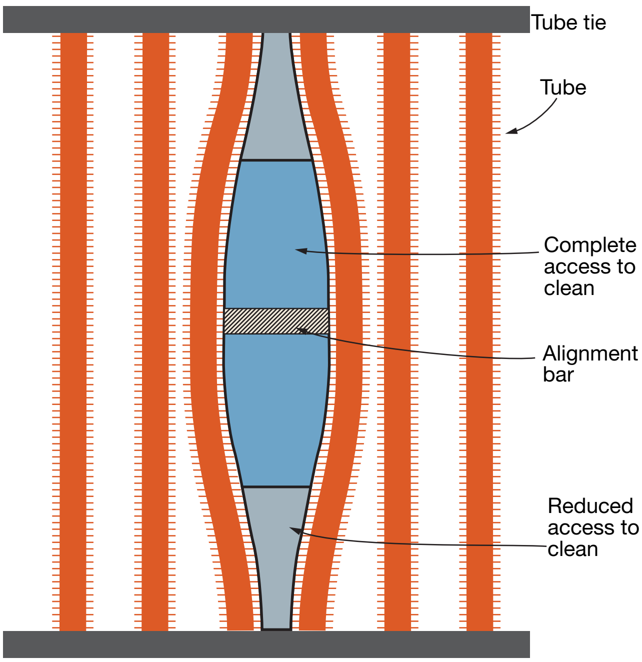
Cleaning procedure

The procedure HRST and PIC prepared for cleaning a 10-yr-old, F-class, double-wide HRSG in the Southeast illustrates the level of planning required for success. The tube bundles downstream of the SCR's ammonia injection point were scheduled for cleaning (Fig 1). The assessment by HRST/PIC indicated that a combination of CO_2 blasting and deep cleaning with high-pressure air would accomplish the owner's objectives.

The design of this HRSG is characterized by staggered 1.5- and 2-in.-diam tubes with varying fin heights. Tube length nominally is 70 ft. The tube bundle closest to the stack is 12 rows deep, the next box is 14 tube rows deep, and the final two are 15 tube rows deep. According to previ-



3. Alignment bars open tube lanes and permit relatively easy access by both end- and side-blow wands for most of the tube length between tube ties



4. Shape of the cleaning lane is roughly elliptical. As sketch shows, access for cleaning is not uniform between adjacent tube ties

ous inspections, the majority of the debris present is rust flakes.

CO_2 blasting is relatively straightforward. The cleaning cycle begins in the stack and works opposite of gas flow towards the HP evaporator 1 face at the extreme right in Fig 1. Work begins at Level 1 and proceeds to Level 6 and back down to Level 1 (Fig 2)—two passes of dry-ice blasting for each of the eight tube-bundle faces. Then the process is repeated moving by blasting each face in turn from the HP evaporator to the stack.

Best practice: When blasting, follow a standard cleaning pattern to be sure debris is removed from each tube. Do not randomly move the cleaning wand all over the tube face.

Deep cleaning takes more time than blasting. It begins on the upstream face of HP evaporator 1 at Levels 6 and 5. When done, a technical advisor (TA) checks cleaning effectiveness, making changes in procedure, air pressure, and/or cleaning heads as necessary. Then the remaining sections of the HP evaporator 1's upstream face are deep-cleaned. There's another TA check at this point, before moving equipment to the next downstream access lane. The procedure is

Qualifying candidate cleaning services

Important to the success of any HRSG gas-side cleaning project is selecting a contractor with the technology and experience to deliver the expected results. Consider seriously a face-to-face interview with each candidate, at a job site if possible. You often learn more from seeing than from listening. Here are a few ideas to help you begin compiling the list of questions for your interviews:

- What's the prospective contractor's experience? Ask for references, including at least one from a plant with the same HRSG you have, and at least one from an OEM.
- How much repeat business does the prospective contractor have? How many long-term contracts?
- What's the experience of the principals who will be running your job? Ask for resumes.
- Will the personnel assigned to your project be employees of the contractor of record or will they be local hires with little or no relevant experience?
- How many people will be on the cleaning team, how many nozzles will be operated simultaneously?
- How many passes will be made on each face? How much time will be dedicated to cleaning each face?
- What cleaning medium would the contractor use on your job? What pressure? High pressures may be needed for severely fouled tubes. Keep in mind that if the cleaning pressure is too low to remove a particular deposit, there is the chance of debris being packed into downstream tubes, making the deposit even more difficult to remove. Can the contractor work at pressures up to 350 psig, or higher?
- Does the contractor have the know-how to spread tube rows (without damaging them) to facilitate access to fouled heat-transfer surfaces and assure a proper cleaning? Note that HRST's patented tools and tube-spreading procedure for deep cleaning have been licensed only to Precision Iceblast Corp and Master Lee Industrial Services.
- Will the contractor's supervisor escort you on a full inspection up and down the faces of accessible bundles to assure your satisfaction with the job?

repeated for each of the remaining seven faces.

Alignment bars are inserted into the face of tube bundle being cleaned, level by level, at a location roughly equidistant between the tube tie above and the one below. The technique is illustrated in Figs 3 and 4.

Once tubes are spread on one level, the side wand uses high-pressure air to clean above and below each alignment bar as it is moved deeper into the tube field. Penetration of the tube bundles should be five or six tubes deep from either side, meaning foulant will be removed from most tubes.

Next, the end-blow wand is used in areas tough to reach with the side-blow wand—such as near tube ties, around any physical interference, etc. When a given level is finished, alignment bars are removed and moved down to the next level. At the end of the job, be sure to go up and down the face of each tube bundle to verify cleanliness. Bring along a borescope to look deep into the tube bundles.

The editors spoke with the plant supervisor responsible for overseeing the tube cleaning project to learn more about the benefits accrued. Unfortunately, with other work going on, including change-

5. Tube bundle is fouled with rust and other deposits

6. First cleaning pass using CO_2 eliminates most deposition on tubes near the face of the tube bundle

out of the control software, as well as inconsistent run time, definitive performance numbers couldn't be compiled.

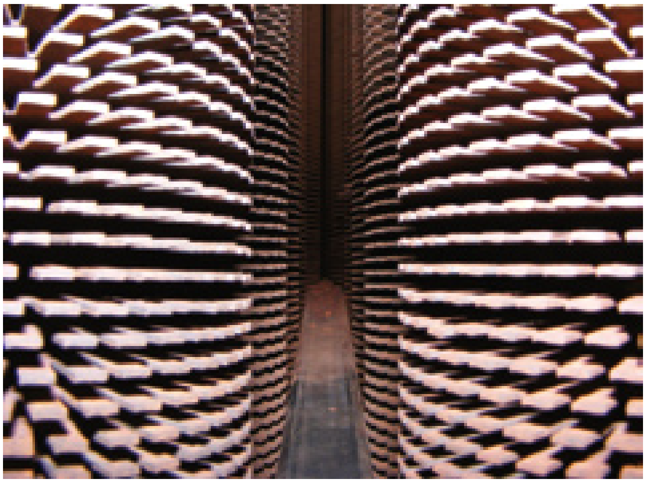
A photo record of another cleaning project illustrates the qualitative effectiveness of a combination CO_2 blast and HP-air deep cleaning program. Fig 5 presents the challenge, Fig 6 shows how CO_2 eliminates debris at the face, Fig 7 shows stakes in place to enable deep cleaning, Fig 8 confirms the effectiveness of deep cleaning, and Fig 9 shows debris at the bottom of the unit piled more than 18 in. deep in places. Upwards of 7 tons of rust and other debris were carted away from this HRSG.

7. Alignment bars are inserted by protected technician to spread tubes and allow deeper penetration of the cleaning wands

You can do back-of-the-envelope calculations on the economic value of tube cleaning using the following information from GE report GER-3567H, which states that for a 7EA a 4 in. H_2O exhaust pressure drop over design translates to:

- Power output loss of 0.42%.
- Heat-rate increase of 0.42.
- Stack temperature rise of about 2 deg F.

The maintenance manager for a 7FA-powered combined cycle said he believed the numbers were about the same for his unit. He added that the backpressure alarm is set at 20 in. H_2O on his turbines and that they trip at 24 in. CCJ



8. Effectiveness of tube spreading is evident by comparing this photo with Fig 6

9. Foreign material removed from finned tubes must be collected and sent to a landfill

Eliminate leakage by drain, vent, block valves

Many plant managers will tell you that much of the work required to make a new combined cycle a competitive generation asset doesn't begin until after the facility is commissioned and the construction/startup crew drives out the gate and off into the sunset. It's a tough pill for experienced plant personnel to swallow, but they are well aware that many independent power producers focus on initial cost and schedule to meet their pro formas. Lessons learned and best practices often are ignored when developing a spec to build a plant that puts power on the grid as quickly and as inexpensively as possible.

Small valves, in particular, may fly "under the radar." Hundreds of blowdown, drain, and vent valves on heat-recovery steam generators (HRSGs) and turbine steam supply and extraction systems often are sourced offshore from suppliers with questionable quality-control practices. These valves typically are of the gate type, which are marginal for the intended duty in most cases. The bottom line: The valves don't last long and must be replaced.

Budgets, of course, always challenge good judgment. Instead of replacing all HRSG drain valves, for example, plant personnel typically are asked to monitor them and replace leakers at the next outage, as necessary. It can take years to overcome poor decisions.

Bob Morse of New Hampshire-based Bremco Inc, industrial contractors specializing in powerplant equipment installation, upgrades, and replacement, told the editors he often is called to generating stations to replace valves. Some plants, he says, do acoustic surveys of drains on a regular basis to identify ineffective valves. Selection of replacements generally is a matter of personal preference and not based on an engineering evaluation of the specific situation.

Many valves don't have a chance, he continued, because their seats are compromised during heat treatment. With all the things an owner must check/verify during construction, how carefully can drain-valve installation be monitored? Morse said he often has a difficult time getting heat-treatment specs from valve manufacturers and most suppliers do not provide welding guidelines in writing.

Conval Inc

1. Manual ball valve has removable top for maintenance and inspection. The copper-coated ring is the body-to-bonnet seal

A way to protect valve seats against excessive heat during installation might be to have them supplied with shop-welded "safe ends" (nipples). This is particularly important for 91 material because of its post-weld heat-treat requirements.

Morse said it's not uncommon to find drain systems with mixed materials. For example, P91 piping and F91 valves would be close to the HRSG where temperatures and pressures are highest, 22 material further downstream, and carbon steel near the end of the circuit where temperatures and pressures are lowest. Where this is the case, plant personnel need to be sure replacement valves and piping are matched up correctly; also, that the contractor hired has a QC program in place that lets its personnel weld the material being worked on.

The maintenance supervisor for a 2 × 1 7FA-powered combined cycle said valve issues were identified in the steam-turbine drain system at his facility only months after commercial operation. Valves ranged in size from 1 to 2.5 in.

Conval Inc

2. Three types of ball-valve actuators: gear, pneumatic, manual (l to r). Gear operator comes standard on 3- and 4-in. valves from at least one manufacturer because the torque required to operate these valves is so high the handle length would be impractical. Unit shown with large-diameter handwheel has a 4:1 gear reduction, facilitating its operation

Conval Inc

3. Ball valve, 1 in. and pneumatically operated, is installed in drain line to handle 2300 psig/950F steam conditions

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Our Camseal zero-leakage ball valve is a favorite among combined cycle plant personnel.

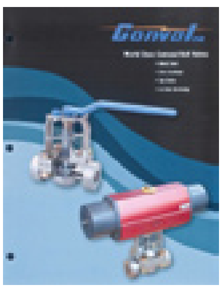
When Combined Cycle Power Plants are designed and built, many of the original actuator/valve packages include lower-quality, foreign-made globe, gate and ball valves.

Time and experience show that these inferior valves only last a few years or less. **By comparison, when U.S.-made Conval valves are specified and installed, typical valve life is 16-20 years.**

Based on this real-life experience, more plant maintenance supervisors and planners are choosing to replace original lower-quality, foreign-made valves with new Conval Camseal ball valves, Swivldisc gate valves and Clampseal globe valves.

Sometimes plants already stock Conval valves. If they do not, factory deliveries are good. If the original valves are actuated, Conval can match the footprint of the actuator for easy replacement.

Based on users' experience, Conval valves are being used in such key combined cycle locations as isolation, vents, drains and feedwater. By their very nature, plants frequently cycle up and down, on and off, which is very difficult on any mechanical equipment. **Most OEM valves simply cannot perform in these highly demanding circumstances. Plant personnel are discovering that Conval is the smartest, most economical valve choice from a total life cycle standpoint.**



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Even earlier, problems arose with the HP bypass desuperheater, which takes spray water off the intermediate-pressure (IP) boiler-feed pump. The stop and control valves for that device were globe-type.

Their Teflon and PEEK seats (wrong materials) stuck within the first hour of operation. The stop valve was replaced with a ball valve, which is less expensive than a premium globe. Ball valves also were installed in the problematic steam-turbine drain system. In both cases, the solution met expectations.

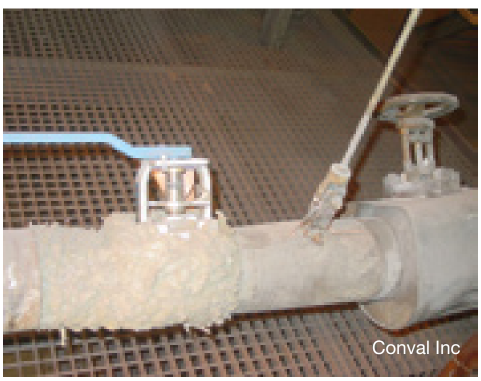
The durability of the plant's original valves for main, cold-reheat, hot-reheat steam drains, and attemperator stop and control service, came under question by management. A list of critical drain valves was developed and annual monitoring of leak-by was conducted to be sure the plant was not losing efficiency. Ports of about 1 in. in diameter were cut into the insulation to accommodate the acoustic sensor on the "listening device."

Manual and motor-operated block valves for attemperators were switched to air-operated actuators for simplicity.

The maintenance supervisor told the editors that many of the valves were F91 and had P91 pipe on the upstream side and P22 on the discharge side. The plant continues to survey drain valves for tight shutoff and to replace leakers during maintenance outages. Replacement valves are selected based on compatibility with operating conditions. Ball valves are preferred.

Valves. The editors next spoke with VP Mike Hendrick of Conval Inc, Somers, Ct, which makes a wide range of globe, gate, and ball valves for high-temperature/high-pressure service, to get his recommendations concerning the problematic drain and attemperator block valves supplied with many new combined cycles.

Hendrick prefers ball valves to meet the on/off (never throttling) demanding service needs of isolation, vent, and drain valves. For the temperatures and pressures experienced in F-class combined cycles, Conval offers ball valves up to 4 in. This size range satisfies most HRSG applications, including attemperator block valves.



4. Ball valve for main-steam drain isolation service replaced an ineffective gate. Body is of F91 material

Quality (eight-turn) globe valves don't leak in demanding drain service, but they are more expensive than ball valves. An advantage globe valves have over ball valves is that you can (but shouldn't) torque down on the stem and slow or stop the leakage; can't do that with ball valves. Stems of ball-type attemperator block valves sometimes snap off because of rapid actuation and abrupt stop.

If "zero-leakage" ball valves leak, it probably is because of distortion in the seat area attributed to the weld process—such as post-weld heat treatment. Welding into a pipeline must be precise, cautioned Hendrick. And when post-weld heat treatment is required, consider valves with safe ends as suggested by Morse of Bremco. Also, be sure lines are clean before operating valves to assure seats will not be scored.

Select your valves carefully. Be sure metal seats are available when service temperatures are 400F and above, stems are blowout-proof, seat leakage meets the tightest specs after installation, coatings assure long life, and can be accessed internally, inline, for inspection and maintenance (photos). CCJ

Report card: Straight 'A's

Plant Manager Dean Motl and the staff at New Harquahala Generating Co LLC (NHGC), Tonopah, Ariz, always have the welcome mat out for the editors. This is an "involved" group, participating in and presenting at user-group meetings, contributing their ideas to the CCJ's Best Practices Awards program, etc. Motl believes in sharing the plant's success stories because he knows the dialog will beget ideas for New Harquahala in return. Everyone can learn, he says.

NHGC, which began commercial operation in fall 2004, has three 501G-powered 1 × 1 combined cycles with a total capability of 1092 MW. It is owned by MachGen Holdings LLC, managed by Competitive Power Ventures, and operated by NAES Corp. The merchant plant's "run season" typically extends from mid June through mid October.

A few months back, the editors were driving to Phoenix and called ahead with the hope of "catching up." Motl was waiting at the door at noon and invited the editors into the conference room where most of the available staff was gathered to listen to a lunch 'n learn presentation by Hal Scott of Proton Onsite—formerly Proton Energy Systems—on the benefits of generating hydrogen at the plant rather than having it trucked in.

Some facts noted during the presentation:

- Nominal cost of hydrogen is about \$0.75/100 ft^3 in electricity and water.
- Proton's H series units, the focus of the presentation, come in nominal sizes of 75, 150, and 225 ft^3/min.
- Lifetime of the membrane stacks that produce the hydrogen is about seven years. The replacement cost for one stack, capable of producing 75 ft^3/min, is about \$20,000.

Next, the advantages of onsite production were noted: high purity at low cost, no demurrage charges on bottle trailers, better neighbor (no large trucks traveling on local streets), no hydrogen stored onsite, etc. Back-of-the-envelope calculations for NHGC put the payback period at about 15 years based on economics alone. That number would drop depending on the value placed on enhanced safety, being a better neighbor, etc. Where Motl's plant is located the "soft" benefits would likely have little positive impact on a buying decision.

Scott and the pizza finished, it was time to learn how Motl and company were improving plant performance and personnel safety. First stop on the plant-wide tour with Motl, Operations Manager Jake Mattingly, Maintenance Manager Chris Bates, and Plant Engineer Nick Hayes was the warehouse. The first thought that runs through your mind: Why are we stopping here?

Good reason: The warehouse essentially runs itself. There is no person checking things in and out. Packages are received by the maintenance staff and placed on a shelf where advised by a document (for example, boiler-feed pump parts are Aisle X, Section Y). Inventory control is accomplished when a particular part is removed and work-order and part bar codes are linked. Might not work in Crooklyn, but in the Arizona desert it's a success. The last two semi-annual inventory checks revealed shortfalls of less than \$200.

Walking to the next stop at the gas receiving station, the group passed the cooling towers, scene of the plant's success in eliminating lube-oil issues in fan gearboxes. If you are not familiar with how NHGC put an end to problems with lube-oil contaminants, including water, for an out-of-pocket cost of only about \$4000 per cell, read "User group gets an assist on fan gearbox lube-oil solution" in the 4Q/2009 issue. You can access it at www.ccj-online.com. A significant side benefit was a safer work environment.

The gas receiving station shown in Fig 1 consists of two 100% coalescing filter towers. They were installed two years ago after a hydrocarbon slug

1. Coalescing filters protect against gas liquids (left)

2. Component barcodes link to work management program (below)

3. **Removable insulation** facilitates P91 hardness surveys

4. **Fin-fan cooler** allows use of GT compressor air for plant use

5. **Plant valve mods** eliminated shaft/bushing binding and resultant automatic unloads

did some damage. The gas supplier created the slug during pigging and maintenance operations. The plant is connected to the main line with a single radial tie.

It seemed strange walking around a huge plant like New Harquahala and being able to carry on a conversation. But Motl said the facility can spring to life virtually in a heartbeat. It can be brought out of standby condition and started in less than half a day. The plant manager also was quick to point out that work never stops; improvements are ongoing.

A case in point: The digitizing of P&IDs so everyone has access to the latest drawings via SharePoint® ("Improve plant communication, document control," 1Q/2011, Best Practices Awards for Management). Interestingly, these drawings often are linked to images of specific equipment so personnel assigned to an O&M task can readily identify them in the field.

Another project was to label and barcode all pipes and components (Fig 2). A barcode scan links to the work management program and other documentation that provides relevant information for maintenance, repair, replacement, operation, etc.

NHGC has been cited often for its P91 condition assessment program ("P91 commands respect," 2Q/2010). To facilitate future inspections for trending material degradation, soft insulation covers were installed in critical areas for rapid access (Fig 3).

Plant and instrument air are taken from the compressor shells of operating units. Air flows via the kettle boilers (rotor air cooler, RAC) to a fin-fan cooler/pressure regulator/water separator. The unit shown in Fig 4 serves the entire plant. Unreliability of plant air compressors forced this design modification. They tripped frequently in summer, resulting in unreliable air availability. The alternative, a standby diesel-powered compressor, cost $10,000 per month to rent (plus fuel). The original air compressors are used in cooler weather when the plant is not in service.

Certain operating conditions call for air to be bypassed around the kettle boiler. Unfortunately, the bypass valve was prone to sticking in the closed position (Fig 5). Plant personnel traced the problem to materials incompatibility at the temperatures experienced. Solution was to change the bushing material to Stellite from Type 316 stainless steel; the shaft to Type 422 stainless from Type 316.

While the economics of onsite hydrogen production was not a slam dunk, onsite production of nitrogen is. The 600-scfm Parker nitrogen generator shown in Fig 6 paid for itself in about 18 months because of the large volume of gas required during layup (three G-class triple-pressure HRSGs, kettle boilers, and welding purge gas).

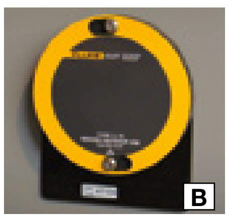
Protection of personnel against arc flash was a major safety initiative at NHGC. Fig 7 shows the infrared windows used to allow thermographic monitoring of medium-voltage switchgear without opening panels. Clear, concise instructions also are mounted right on the panels.

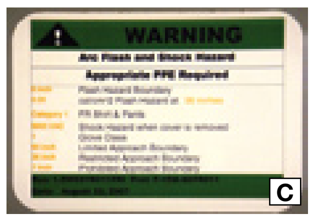
SCR fans with grease bearings were prone to overheating in summer and tripping, much like the air compressors. Solution was to retrofit with a water-cooled bearing housing and use oil for lubrication.

The plant's TXP control system was replaced with Siemens Energy's T3000 shortly after the latter became available. Plant personnel say it's as robust and user friendly as advertised.

Finally, if you're interested in how New Harquahala converted from a passive to proactive vibration monitoring system and about the benefits that accrued to the plant, access "Hands-on vibration monitoring program safeguards critical rotating equipment," 1Q/2010, Best Practices Awards for BOP O&M. CCJ

6. **Long periods of layup** make onsite nitrogen production cost-effective





7. **Arc-flash safety practices** for medium-voltage switchgear (A) include use of infrared windows for thermography surveys (B) and clear instructions to protect personnel (C)

The total plant concept

The CTOTF Spring Turbine Forum at The Williamsburg Lodge in Virginia's Colonial Williamsburg, April 15-19, is coming up quickly. It is the meeting of choice for gas-turbine owner/operators who need information on more than just one engine model, so it's ideal for generation executives, asset managers, and plant managers.

Access the agenda at www.ctotf.org and you'll see roundtables for GE legacy, aero, and F-class engines; the gamut of Siemens engines; Pratt & Whitney FT4s and FT8s; and Mitsubishi and Alstom gas turbines as well. Digging into the agenda it's easy to understand why CTOTF Chair Bob Kirn of TVA says the meeting is in lockstep with the group's tagline, "The Total Plant Concept." The meeting does not just address gas turbines. Note the sessions dedicated to industry issues, O&M and business practices, combined-cycle plants, generators, controls, electrical systems, emissions control, etc.

The CTOTF organization chart on p 96 offers a capsule summary of the subject matter addressed as well as the industry experts responsible for coverage of those areas.

Want to know more about the subject-matter experts? Just access the org chart at ctotf.org and click on the person's name for an abbreviated resume. Have a question regarding upcoming content, an idea for a presentation, etc? Use the handy e-mail feature. Want to evaluate the content in formal presentations? Just hit the IBBCS button on the home page (left-hand toolbar).

Keep in mind that formal presentations are only the tip of the iceberg, so to speak, in terms of value-added content available at a CTOTF conference. Informal presentations and discussion forums dominate the program. You can only benefit from those information resources by attending.

Not done promoting yet: Two more outstanding features of the Spring Turbine Forum are the presentation of the **CCJ**'s 2012 Best Practices Awards and the training benefits of CTOTF's three-hour CT-Tech sessions on Tuesday and Wednesday evenings. You'll get the details on the Best Practices projects that received the highest recognition from the judges; one or more ideas might benefit your plant. Regarding CT-Tech, see details on p 97.

HRSGs at CTOTF

A good example of both The Total Plant Concept™ and the value of informal presentations was the recent effort by a G-class plant manager to highlight real-world issues his plant was experiencing with a triple-pressure heat-recovery steam generator (HRSG). His main discussion points:

- Problems identified with poor design of the restraint system for the perforated plate at the entrance to the HRSG.
- Floor-plate failure and the catalyst and tube fouling caused by the release of insulation.
- Wall damage in the duct-burner bay.
- Forced outage caused by an LP steam-drum leak.
- Salt fouling of finned-tube surfaces and corrosion damage to piping from salt.

The takeaway from this presentation was that owners driven by low first cost might want to reconsider their goals and switch instead to a low-lifecycle-cost strategy. Operational penalties and the cost of design corrections can be substantial.

The first item on the speaker's agenda was the perforated plate. The top guides for the perf plate didn't slide to accommodate growth as intended and the top structural support for the perf plate tore loose. In addition, tee-shaped side restraints at six elevations apparently were impact points for the plate during cyclic movement. Audible banging and material distress were in evidence. The installation of so-called plate boxes distributed the impact and reduced the clearances between the perf plate and restraints.

The bottom center is the only place the perf plate is welded to the HRSG (Fig 1). The weld was found compromised at every annual inspection, leading the speaker to believe that a pinned connection may be a better alternative. What the plant did, with a measure of success, was install reinforcement plates inside the perf plate to build up the bottom center anchor (Fig 2).

The plant manager said it was common to find ligament cracks in areas of the perf plate with high porosity. Missing sections are not unusual (Fig 3). Best practice: Maintenance personnel added a man door in the perf plate to facilitate access to the back side for repairs (Fig 4).

First floor-plate damage experienced was attributed to inadequate lap seam between duct sections (Fig 5). Later, plates were damaged by impact of the expansion-joint baffle which broke loose and sheared off pins. Corrective action: Expansion-joint baffles were reinforced with ribs.

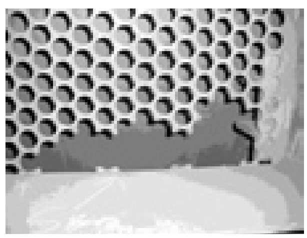
Interestingly, floor plates near the perf plate were installed with a lower pin density than plates closer to the gas turbine. Former were were more susceptible to damage by vibration and turbulence. Insulation released from areas where the plates failed fouled the catalyst face and finned heat-transfer surfaces (Fig 7). Impact of fouled catalyst was a forced reduction in engine output to meet air-quality limits, as well as a unit trip on high backpressure. Such restrictions cost the plant $1 million in lost production and efficiency one winter alone.

Duct-burner wall failure was caused by high heat flux (Fig 8). First heat deflector was removed from the burner to correct the issue.

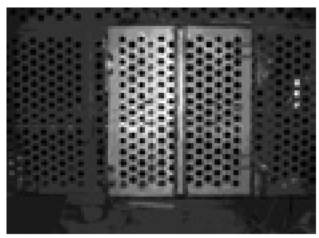
A leak in the LP drum was identified by "whispy" steam coming up from under the insulation. A crack was found on the bottom of the drum, running longitudinally near the 6 o'clock position at mid vessel (Fig 9). Inside the drum, an angle support leg for the feedwater distribution header broke loose from where it was welded directly to

1. Perf plate is welded to the HRSG only at the bottom center position

2. Reinforcement plates were installed on the inside face of the perf plate



3. Sections of perf plate often go missing



4. Man door allows access to the back side of the perf plate

5. Floor-plate damage allowed release of insulation

6. Floor plates can carry away because of a poorly designed restraint system (low pin density)

7. Catalyst face is fouled with insulation

8. Wall around view window was damaged by heat from the duct burner the drum (Fig 10). Correction was to install a baseplate and weld the support leg to it (Fig 11).

Fouling of finned tubes from the HP economizer section to the stack was a thorn in the side of this plant manager. Ammonium bisulfate is the problem, he said. It combines with iron from the finned tubes to produce a rock-like deposit. Rust by itself is not an issue. The buildup is so acute the plant has never operated at maximum output. The as-new backpressure is about 22 in. H_2O; alarm is set for about 27 in.

Annual attempts at conventional cleaning with dry ice and compressed air have been only partially effective, he noted. Backpressure is only lowered by 1.5 to 2 in., which equates to 7-8 MW. One section of the HRSG is particularly difficult to clean. It encompasses nine rows of evaporator tubes (three headers) sandwiched between two rows of superheater tubes and six rows of economizer tubes—without a passageway.

Plant staff removed the baffles from the LP economizer section to reduce the backpressure and picked up about 0.5 in. However, that raised the stack temperature and steam turbine output dropped by 5 MW.

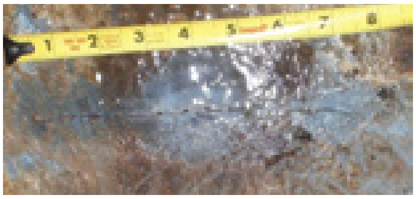
The plant is challenged by having to burn Canadian gas with 20 ppm sulfur. Excess ammonia runs about 5 ppm (NO_x emissions are limited to 2.5 ppm). Salt from nearby water is not an issue; the gas-turbine inlet is equipped with HEPA filters, which work "pretty well," the PM says.

Attempts to solve the tube fouling problem include liquid nitrogen (no good), and a sonic horn. Latter works "to some extent," but only near the device. Sound is attenuated quickly. The plant maintains the compressor inlet at between 35F and 40F to maintain the backpressure as low as practicable in cold weather.

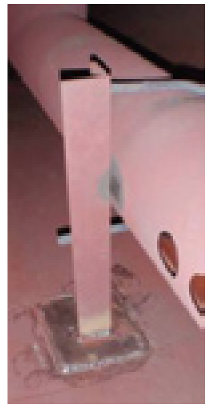
Next trial will be to see if the deep cleaning procedure outlined in the article on p 82 is beneficial. If that is conducted as planned, you'll likely find out by the fall meeting if not at the upcoming Spring Turbine Forum. Other possible solutions include the following:

- Reduce the sulfur content of fuel gas; however, this likely would not be economically viable. Removing odorants might have a positive impact because mercaptans are high in sulfur.
- Reduce ammonia use by retrofitting an ultra-low-NO_x combustion system.

Another problem associated with fouled tube surfaces is corrosion of the drain system.



9. A crack in the LP drum was found at mid vessel near the 6 o'clock position



10, 11. Support leg for the feedwater distribution header inside the drum was installed incorrectly above; correct installation demands use of a baseplate (right)

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Prevent the damaging effects of stray voltages on rotating shafts

Some rotating machines, because of their electrical or mechanical characteristics, induce an electrical potential (voltage) on their shafts during operation. Experts at Bently Nevada, Minden, Nev, warn that if this voltage is not managed, or if the grounding system fails, the voltage seeks an alternative path to ground. That path is the metal component closest to the shaft—typically a bearing or seal.

The electric arcing that occurs, called electrostatic discharge, erodes metal surfaces and opens the tight clearances that these components depend on for proper operation (Fig 1). If undetected, electrostatic discharge will gradually destroy the bearing or seal, change the rotor dynamics of the machine, and may even damage the shaft.

Carbon brushes are most commonly used for shaft grounding, say engineers at Magnetic Products & Services Inc, Holmdel, NJ, even though they consider them unsuitable for such duty. Reasons may include one or more of the following:

- They do not operate satisfactorily in the presence of oil and dirt.
- Satisfactory performance is possible only when cooling air contains at least 3 gr/ft^3 of water vapor.
- A carbon-brush current density of 40-60 amp/in.^{2} must be maintained at the brush contact surface. This goal is virtually impossible to achieve at normal, very low grounding currents.

Failure to satisfy any of these conditions can initiate the build-up of a highly resistive glaze at the carbon-brush contact surface, and this is conducive to arcing and overheating. Note, too, that if copper straps are used for grounding, the need for frequent maintenance can be expected. They can become fouled with dirt in just a few days of operation.

1. Stray shaft currents caused arcing that damaged this thrust-bearing shoe

Cutsforth Inc, Bloomington, Minn, introduced in mid-December a grounding system featuring dual copper grounding ropes that is said to maintain shaft voltages at lower levels than traditional solutions—even in dirty environments and where ventilation and cooling air are not filtered. The system's universal mounting feature permits its installation on all OEM models and frames (access details at www.cutsforth.com/shaftgrounding.php).

To maintain shaft voltage at a very low level, Cutsforth uses a redundant collection system that includes both grounding ropes and carbon brushes, both of which can be removed and replaced with the machine in service (Fig 2). It's as simple as flipping a switch, according to CEO Rob Cutsforth. The design also allows for quick measurement of shaft voltage with a standard voltmeter.

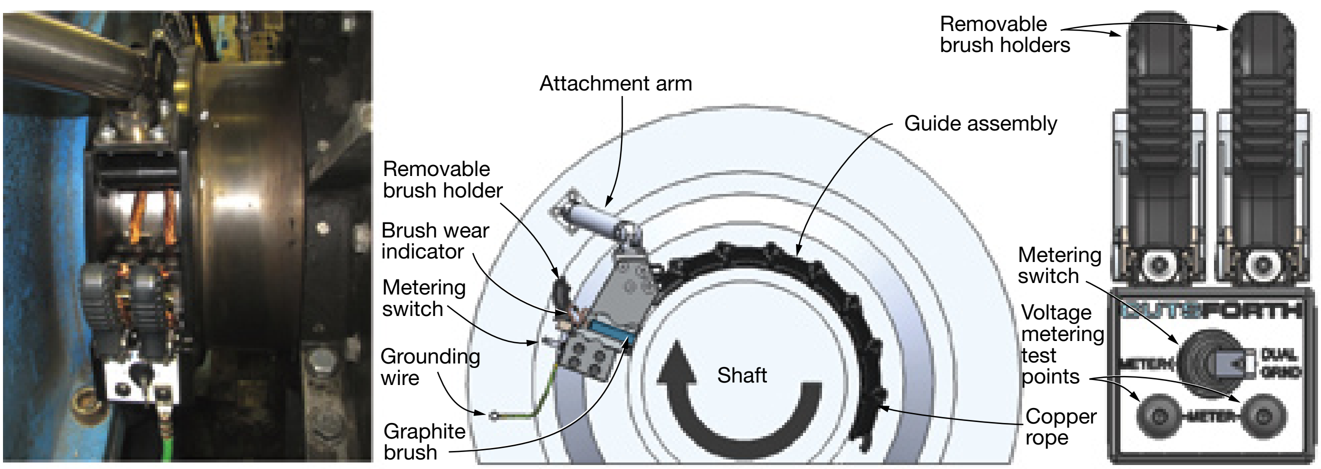
Cutsforth is a product design, manufacturing, and services company specializing in removable generator brush holders and online collector-ring truing services.

Pratt & Whitney forms strategic alliance with Wood Group GTS

Pratt & Whitney Power Systems (PWPS) announced at Power-Gen International in Las Vegas in mid-December that it has formed a strategic alliance with Wood Group GTS to jointly service the industrial gas turbine aftermarket. Specifically, GTS has been granted an exclusive 10-yr license for the sale and distribution of PWPS-manufactured combustion hardware, hot-gas-path (HGP) components, and high-technology repair services.

The guarantee on parts availability helps GTS compete against the OEMs and other third-party providers of long-term service agreements. PWPS benefits by having a proactive partner with world-class maintenance capabilities to help keep its shops humming, while retaining the right to directly sell parts and repair services on a transactional basis.

Recall that PWPS and GTS have worked together successfully for years in the aero market. Their joint-venture company, Wood Group Pratt & Whitney, has service shops dedicated to the inspection, overhaul, and repair of FT4 and LM2500 engines. For the "F" technology market, PWPS President Peter Christman remarked, "The combination of PWPS' engineering, new-part manufacturing and repair technology, and GTS' service experience and risk-management strategies



2. Cutsforth shaft grounding system, installed at left, is described in center cutaway and brush-section detail at right. Note that the copper rope terminates about halfway inside the last section of the guide assembly. A video on the website shows how easy it is to remove and install the copper rope

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is a compelling proposition."

FT4000 Swiftpac. Also announced at the conference was the development of the FT4000 Swiftpac®, which is based on one of the aviation industry's most widely used aircraft engines—the PW4000 turbofan. It has more than 26-million hours of operating experience on the Airbus A330 and Boeing 777 airframes. The FT4000 Swiftpac will be offered in 60- and 120-MW compact power blocks designed for simple-cycle, combined-cycle, or cogeneration service.

The new land-based package promises 41% efficiency without the complexities of intercooling. It features a modified core compressor and turbine from its aero parent—maintaining more than 90% parts commonality with the PW4170 and PW 4090 engines. Plus, it has a new LP compressor and power turbine, both designed for durability and enhanced onsite maintainability. An advanced airfoil design and variable geometry contribute to optimized performance. Wet compression is provided boost power output at ambient temperatures above ISO conditions.

An FT4000 prototype will be available in 2013, production units the following year.

APR Energy. Finally, PWPS presented the details of a strategic partnership with UK-based APR Energy plc to jointly address global temporary power needs and to increase the availability of mobile turbines.

Executives noted that the partnership already has facilitated APR orders totaling 100 MW on a flexible delivery schedule. Under the terms of the global agreement, APR is the *exclusive* provider of PWPS' FT8® Mobilepac® rental power solutions. The company also benefits from a 12-month warranty, five-year service agreement, and access to dedicated global support from the engine maker—including project management, engineering, and aftermarket resources.

The FT8 Mobilepac can be installed at a prepared site in eight hours and be producing 25 MW of emergency power within a day. The generating unit comes in two trailers, has dual-fuel capability, and can be connected to 50- or 60-Hz grids. The first trailer contains the gas turbine, electric generator, exhaust collector, diffuser, and engine lube-oil system; the second carries 15-kV switchgear, control system, operator panel, protective relays, batteries and charger, motor control center, and hydraulic start package.

Wood Group helps powerplant owner/operators reduce life-cycle costs

Wood Group GTS was built through the acquisition of many companies offering specialized services for industrial gas turbines. Integration of such diverse resources is challenging and takes time. GTS' goal of providing the industry a comprehensive O&M solution focused on equipment life-cycle cost reduction is now a reality, the editors were told at Power-Gen International in mid-December.

The final pieces of the "puzzle" fell into place with the acquisition of Dublin-based Shanahan Engineering at the end of 2009, the acquisition of Gas Turbine Efficiency Ltd (GTE) in November 2011, and the signing of the license agreement with PWPS described in the previous article.

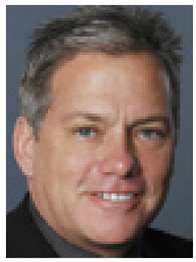
The Shanahan purchase provided GTS a geographic footprint in the Eastern Hemisphere and a closer working relationship with equipment OEMs, which is important for projects where new equipment is required. The EPC contractor also brought to Wood Group its plant commissioning and maintenance-service expertise.

That acquisition already has borne fruit. Wood Group expects to complete the conversion of two 7EA simple-cycle peakers in California to a 335-MW combined-cycle plant in the mid-2012 timeframe and it is under contract to build an 800-MW combined cycle in Israel powered by a dozen LM6000s.

The GTE acquisition expanded Wood Group's capabilities in several areas and made a meaningful contribution to the company's ability to provide gas-turbine performance-based solutions. To illustrate:

- The compressor cleaning system developed by GTE is installed on more than 800 stationary gas turbines and has over 20-million hours of run-time.
- ECOMAX™ automated engine tuning technology continues to generate positive feedback for its ability to protect GTs against emissions

Turner relocates to Bangkok



Marcus Turner, a familiar face at user-group conferences both as the chief marketing officer of Gas Turbine Efficiency and as CEO of Control Center LLC (one of the companies acquired by GTE), is the new VP sales for Asia/Pacific at Wood Group GTS. He relocated to Bangkok at the end of 2011. Catch up with Turner at this new email address: marcus.turner@woodgroup.com.

PROFESSIONAL SERVICES

Plus new/used equipment, tools, parts

excursions, lean blowouts, and excessive parts wear caused by high combustor dynamics.

- Skid-based fuel systems from GTE, installed in many plants, are equipped to condition gas for optimal combustion as well as to measure its flow and determine its composition.
- Fogging systems boost power output on hot days.

The PWPS agreement enabled GTS to enter the "F" technology market with comprehensive maintenance solutions complete with a long-term service contracts. Wood Group CEO Mark Papworth said the company's "package provides a truly 'independent' and high-quality solution for F-technology units to mitigate the technical and commercial risks of turbine operation." He added that "We have a track record of service innovation and of lowering the cost of ownership for industrial gas turbines."

3. PWPS' Chuck Levey (left) and WG's Frank Avery share a light moment during press conference to announce the companies' new alliance

Wood Group's Frank Avery, who manages the company's Power Plant Services business unit, and PWPS VP Chuck Levey explained during a press conference why the two companies formed this alliance and how 7FA owner/operators benefit (Fig 3). Opportunity was a major factor in the "why." Many existing service agreements will expire over the next several years, the business leaders said, opening the door for third-party providers. Focus of the alliance is to grow the companies' share of this emerging market.

"How" 7FA operators will benefit from the alliance include the following, Avery and Levey told the group:

- Doing business with a leading independent services provider which puts customer interests first.
- Providing customer assurance with proven solutions for new-parts supply and high-technology repair services.
- Achieving lower equipment life-cycle cost by working with a team having a solid track record of service innovation.
- Optimizing turbine performance through a basket of services that include dynamics monitoring and tuning, power augmentation, etc.

Commercial success was only a heartbeat from the signing of the agree-

4. Wood Group was awarded a multi-million-dollar contract by Associated Electric Cooperative Inc to manage its Dell Power Plant as Power-Gen drew to a close

Wood Group a world leader in gas-turbine MRO services

Wood Group GTS consists of five business units with Mark Papworth as CEO. The firm has been in business for more than 25 years, has annual revenues of over $1 billion, a global customer base, and more than 4000 employees in 15 countries. Wood Group's primary objective: Apply its expertise to increase the performance and reliability of critical rotating equipment so customers can maximize the return on their power-generating and mechanical-drive assets. The five business units are:

- Power Plant Services, headed by industry veteran Frank Avery, provides O&M, repair, and overhaul services for simple-cycle, cogeneration, and combined-cycle facilities. This group is responsible for the operational performance and system reliability for its customers' power generation assets. More than 20,000 MW of installed capacity worldwide currently is under contract. Service agreements are offered in a full range of flexible contractual models to meet all scales of operation, including the following: full care and custody, integrated services, individual services.
- Oil, Gas & Industrial Services, directed by Iain Murray, primarily serves oil companies—national, international, and independents—much the same way Avery's organization serves electric power producers.
- Power Solutions, under the direction of Mark Dobler, operates like an EPC contractor to provide new, serviceable, and refurbished power generation packages and ancillary equipment.
- A fourth business unit manages the company's business relationships with its joint-venture partners. Recall that GTS provides OEM-approved maintenance, repair, and overhaul services for aero engines manufactured by Rolls-Royce, Pratt & Whitney, and GE Energy.
- ASU, the fifth unit, encompasses all businesses that do not fit in the first four—including aero, steam, and union field services. It is headed by Nick Blaskoski.

The GTS management team considers the company the world's leading independent provider of maintenance, repair, and overhaul services for industrial gas turbines made by all OEMs.

ment with PWPS. On the last day of Power-Gen, Wood Group announced that it had inked a multi-million-dollar deal with Associated Electric Cooperative Inc, Springfield, Mo, to manage the utility's Dell Power Plant (Fig 4)—a 2 × 1 7FA-equipped combined cycle (access "Completing a half-built mothballed plant presents special challenges" in the 4Q/2007 archives at www.ccj-online.com). A long-term gas-turbine maintenance contract is part of the arrangement.

GTS is responsible for care and custody of the plant, taking full responsibility for daily operations and routine maintenance, as well as performing all major maintenance services on the gas turbines and balance of plant—including supply of engine HGP parts, repairs, and field service. Wood Group also will install its ECOMAX automated tuning system to optimize GT performance.

Luzzatto hired to 'take Chromalloy to the next level'

Chromalloy is a global technology leader in advanced repairs, coatings, and replacement parts for critical components required in commercial-airline, military, and industrial gas turbine applications. The company has a history of developing innovative and proprietary coatings and processes that allow engines to achieve higher efficiencies by operating at higher temperatures.

Before the acquisition of Sequa Corp, Chromalloy's parent, by The Carlyle Group in July 2007, the company focused on aircraft engines (on-wing and stationary) and had a relatively low profile on the frame side of the electric power industry. Chromalloy was characterized by many geographically dispersed manufacturing, coating, and repair facilities, several of which might be involved in a particular scope of work. At times, communication with at least some shops was challenging.

Armand F Lauzon Jr, who was appointed president of Chromalloy in 2008, overhauled business units and reorganized facilities to prepare the company for growth. Among his most visible and recent accomplishments, Lauzon dedicated a $30-million investment casting facility in Tampa in late 2010 and an adjacent $5-million ceramic core facility in 2011. Both plants are equipped to support F-class gas-turbine fleets. A new Engineering Center of Excellence recently opened in Palm Beach Gardens, Fla; it will do double duty as corporate headquarters.

Lauzon also established joint ventures and strategic partnerships in the aircraft engine and industrial turbine markets—primarily with OEMs and their customers. Last October, with Chromalloy positioned for success in the energy sector, Sequa announced that Lauzon had been promoted to CEO (he retains his position as CEO of Sequa Corp) and Carlo Luzzatto, a seasoned energy-industry executive, had been hired to "take Chromalloy to the next level."

Luzzatto, an electrical engineer by education (Univ of Genoa, Italy), came to Chromalloy with experience in both the electric-power and oil and gas industries. He had business-unit leadership responsibilities at both Ansaldo Energia and GE. Straight-talking, relaxed, and confident, Luzzatto left no doubt during his presentation at Power Gen that he knows well Chromalloy's businesses, customers, and prospects, and the challenges of the energy markets.

A primary goal is to grow Chromalloy's business in the energy sector, which today is less than 20% of revenues. Objective is to increase that amount by 20% in 2012. Luzzatto stressed that Chromalloy was now a "total cycle" company, equipped to take new parts from the foundry to the engine. Perhaps his most interesting slide was one that estimated the global annual worth of service, repairs, and parts (but not upgrades) for all gas turbines in electric-power production at about $16 to $17 billion. A pie chart on that slide showed a typical breakdown in expenditures for an F-class gas turbine at 68% spare parts, 18% repairs, and 14% field service. Adding the first two percentages is indicative of Chromalloy's potential.

Camfil Farr pursues business from the GT inlet to the top of the stack

Camfil Farr had a big-booth presence at Power-Gen—a stand to both showcase new products for gas-turbine owner/operators and to introduce new salespeople. There are perhaps a dozen companies competing for your gas-turbine and generator air filter business. Difficult to differentiate a product and make a buck in that environment, as Camfil Farr knows well. If you thought of this company as a filter supplier, it's time to rethink your impression.

The Camfil Farr representatives left no doubt they were solutions providers from the air inlet to the top of the stack and had the products and engineering capabilities to prove it. A lot of the company's experience is European-based but a gas turbine is a gas turbine no matter where it is, the editors were told. Competitors for inlet and exhaust systems and enclosures are the OEMs and Braden Manufacturing LLC, the leading third-party supplier for this equipment.

The generosity of plant personnel at Tenaska Virginia Generating Station continues to expand year over year, even as staff positions at the nation's combined-cycle plants are being reduced. This past Christmas, TVGS employees and spouses donated more than $4000 to buy gifts for 37 seniors and 28 children in impoverished Fluvanna County.

Shopping complete, they gathered at the home of Maintenance Manager Sam Graham, also vice chairman of the 7F Users Group, on December 10 for a wrap-fest. A week later, the more than 300 gifts were loaded into a convoy of vehicles and delivered to Fluvanna Social Services and to the Monticello Area Community Action Agency for distribution.

The TVGS holiday gift-giving program began in 2004. Plant personnel also donate turkeys and companion foodstuffs to the needy in the community at Thanksgiving. Plant Manager Dr Robert Mayfield and station colleagues participate in other community outreach efforts as well—such as academic mentoring.

Alstom launches Next Generation GT24

Alstom rolled out the details on the Next Generation GT24 and companion KA24 combined cycle at a mid-September customer meeting in its new Chattanooga manufacturing facilities. At that time, the first engine in this new F-class series was being fabricated in the Tennessee plant for a customer in Mexico.

Some industry observers say Alstom may find it challenging to sell a new F-class machine against the G, H, and J gas turbines offered by Siemens Energy Inc, GE Energy, and Mitsubishi Power Systems Americas Inc. But the company doesn't think so.

Alstom believes it has a competitive advantage because the GT24 is designed to provide the operational flexibility generating companies need to be successful in the profitable ancillary services market—including spinning reserve, back-up of intermittent wind and solar renewables, etc.

The defining characteristic of the GT24 is its two-stage combustion system known industry-wide as "sequential combustion." The first stage consists of the company's EV annular combustor and a single-stage HP turbine; the second, SEV (Sequential EnVironmental) burners in an annular combustor and a four-stage LP turbine. Sequential combustion combined with four rows of variable compressor guide vanes enable extended turndown capability and high part-load efficiency. Regarding the latter, heat rate is virtually flat from 100% to 80% of rated capability.

At present, the GT24 is available only in a 660-MW (net), 2 × 1 combined-cycle configuration—known as KA24-2. The 1 × 1 single-shaft version offered when the product line was introduced 15 years ago is no longer available. The GT24 is not designed for simple-cycle service. Gross heat rate (LHV) of the 2 × 1 is 8531 Btu/kWh. Compressor pressure ratio is 35.4:1 and exhaust-gas flow and temperature are 1113 lb/sec and 1107F, respectively. Alstom engineers claim that when fully optimized, the KA24-2 is capable of producing more than 700 MW and operating at over 60% efficiency (both gross numbers).

Part-load performance. At 50% of combined-cycle rated output, relative efficiency is 95% of that at full load—or five percentage points higher than typically possible with a conventional single combustor. Low-load pollutant emissions are enviable as well. At 40% of rated output, NO_x emissions typically are between 2 and 3 ppm. Interestingly, at full load, NO_x is just below

15 ppm. Sequential combustion offers no advantage over a single combustor regarding CO emissions.

While it typically makes little, if any, sense to operate a multi-shaft combined cycle at less than about 40% of rated capacity (because you can shut down one gas turbine and run 1 × 1 with better performance results), the KA24-2 can benefit owner/operators chasing wind by "parking" at 20%—or less, depending on ambient conditions.

Here's how that works: Let's assume must-take wind picks up. The operator backs off on combined-cycle output to maximize renewables generation, down to a nominal 20% of rated load. At that point, NO_x emissions are very close to those at full load because the SEV combustor is shut down and the EV combustor is operating at maximum capability. Several hours later, wind dies down—suddenly perhaps. The operator can ramp up by 450 MW within 10 minutes to meet grid requirements.

Maintenance cycles are of interest to all owner/operators. Alstom expects a 36,000-hr interval to the first hot-gas-path (HGP) overhaul when the unit runs in the maintenance-optimized mode; 28,000 hours for the performance-optimized mode. Three borescope inspections are required during the operating run. There are no combustion and major inspections for the GT24.

Siemens elbows its way into the crowded mid-range GT market

Siemens Energy promoted many products and services from its two-story Power-Gen booth, possibly the largest in the exhibition in terms of square feet. But not much appeared to be new—at least in the editors' minds.

Perhaps of greatest interest to gas-turbine owners and operators in the electric-power and oil-and-gas sectors was the company's aggressive promotion of its almost-new 37-MW SGT-750 engine. It was introduced in November 2010. The Siemens Oil & Gas Div, Houston, is responsible for this machine in addition to all other engines rated from 5 to 47 MW which were purchased from Alstom in spring 2003.

The SGT-750 is designed for both power generation (50 or 60 Hz) and gas compression (and other mechanical-drive applications). It will compete primarily against the well-known LM6000, Frame 6B, and RB211 machines offered by GE Energy and Rolls-Royce. Distinguishing features of the SGT-750 include the following:

- A 13-stage horizontally split compressor with a 24:1 compression ratio and two rows of variable guide vanes for performance optimization.
- Two-stage turbine driver for the compressor.
- Mineral-oil-lubricated tilting-pad bearings.
- Can-annular combustion system with dry low-emissions burners (15 ppm NO_x corrected to 15% O_2). There are eight cans.
- Two-stage free turbine with a nominal speed of 6100 rpm.
- Core engine can be swapped-out for maintenance within 24 hours.
- Efficiency: 40% on natural gas.
- Exhaust flow: 250 lb/sec at 864F.
- Online performance monitoring and data analysis.

Siemens announced its first order for the SGT-750 at Power Gen. Purchaser is Wingas GmbH, a joint venture between BASF subsidiary Wintershall and Russia's Gazprom. It will be installed in the landfall cogeneration station for the Nord Stream pipeline in Lubmin, Germany. The pipeline will link Europe with gas reserves in Siberia. Electric power will be fed to the grid, exhaust heat will be used to reheat the pipeline gas to the temperature required for its distribution.

Monitor the control room on your iPhone, iPad

Emerson Process Management Power & Water Solutions introduced at its busy Power-Gen booth EDS Mobile, one of the electric-power industry's first native applications for users of Apple's iPhone and iPad devices. It uses standard Apple input gestures such as swipe, tap, drag, zoom, and automatic screen orientation.

The motivation for EDS Mobile, said EPM President Bob Yeager, was "the opportunity to give our customers more flexibility in how they manage operations by offering our EDS technology on a mobile platform."

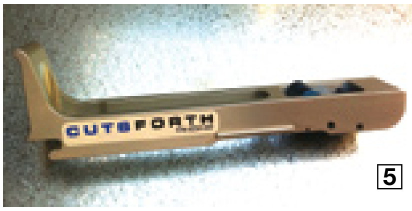
EDS Mobile provides remote users a high-fidelity representation of what the operator sees in the control room. More specifically, EDS gathers information from control systems at a single unit or fleet of units, as well as from other enterprise systems, into one place, presenting near-real-time data such as read-only process diagrams, alarm lists, and trends. Historical data can be accessed as well.

Using a widget menu, EDS Mobile also delivers key performance indicators (KPI), which can be customized to match customer metrics in the areas of fuel usage, plant availability, emissions, generation revenue, efficiency, and power factor. Each KPI icon contains multiple data points, enabling users to drill down to view detailed information and trends in near real time. To illustrate: CO_2, CO, SO_2, NO_x, and opacity data can be viewed through the emissions widget.

The app was demonstrated on an iPad by an Emerson engineer who stressed that there were multiple firewalls between the source of the data and the viewer. Also, that by being read-only, it does not violate any security rules promulgated to date by the North American Electric Reliability Corp.

Products/services

Cutsforth Inc's (Cohasset, Minn) height setter allows the end user to adjust the critical brush-mount height from the surface of the collector ring (Fig 5). It also assures that the position of the brush holder is perpendicular to the center of the shaft. Easy and accurate refitting of the brush rigging is accomplished every time.



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Brush key is a new portable brush and spring changing tool that can be used for Cutsforth's brush holders and shaft grounding products (Fig 6).

Ludeca Inc, Doral, Fla, offers Levalign® Expert as an accurate and easy method for measuring flatness and straightness of machine bases and foundations, split machine casings, as well as flatness and parallelism of circular, rectangular, and odd-shaped flanges. System consists of a self-leveling rotating laser and a sensor which interface wirelessly with a dedicated geometric measurement computer (Fig 7).

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Membrana, Charlotte, NC, introduced a 14 × 40 Liqui-Cel® Membrane Contractor that extends the product line's capacity from 400 to 550 gpm in a single device, making the it the largest membrane contractor degassing device on the market. The additional capacity requires the use of fewer contractors and connections resulting in a smaller footprint and lower capital expense. The new design's increased area also reduces radial flow velocity which results in a low pressure drop (Fig 8).

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Olympus NDT's (Waltham, Mass) instrument rental program offers the latest videoscopes, video cameras, ultrasonic thickness gages, ultrasonic flaw detectors, phased- array instruments, and XRF alloy and environmental analyzers as a cost-effective, short-term solution. The program enables rental of the latest technology loaded with the most up-to-date software, as well as the option to rent an instrument that you've used before. Rentals can be arranged for a single day or for several months and can earn credit toward purchase of the instrument.

The new IPLEX UltraLite videoscope from Olympus offers an easy-to-hold lightweight ergonomic design along with a rugged IP55 compliant casing that stands up to rain, sand, and dust. The device is also available with a wide range of interchangeable optical tip adapters fitted with a bright LED that provides illumination for the viewing field.

BASF Catalysts Div, Florham Park, NJ, reported that its NO_xCAT™ AD series of ammonia destruction catalysts have successfully controlled ammonia emissions controlled to less than 10 mg/Nm^3 with no net impact on NO_x.

Parker Hannifin Corp's Instrumentation Products Div unveiled a new line of quality-assured Type 316/316L domestic and non-domestic seamless stainless steel tubing to complete its tubing, fittings, tubing tools, and training offerings. The line was designed for hydraulic and instrumentation applications in harsh media or corrosive environments where safety, integrity, reliability, and leak prevention are essential (Fig 9).

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Mistras Group Inc's Acoustic Combustion Turbine Monitoring System (ACTMS™) was successful in detecting and locating an S1 vane crack in an F-class combustion turbine at a NextEra Energy Resources combined-cycle generation facility. Jim Keener, VP of Power Generation Technical Services for NextEra Energy said the system was "effective in detecting stationary airfoil cracking on running combustion turbine compressors."

First Independent Rotor Services, Houston, Tex, has designed a unique F/7F rotor transportation skid that provides better support over long distances. The new design, which is made with 100% domestic steel, has machined diameters on the support end in which the journals or shaft areas can rest, and which allows for a 0.625 in. stabilizing layer of rubber or other padding to wrap around the journals (Fig 10). The design also includes supports bolted on top that secure the rotor axially during transport. Because there are so few rotor transport skids available—and none to rent—FIRST will manufacture new skids as needed.

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ESCO Tool, Holliston, Mass, introduced the MILLHOG® APS-438 air-powered saw and EscoTrack™ system which allows operators to cut sections of waterwall boiler tubes with increased efficiency. The leading edge of the blade cuts each pipe with ±0.125 in. accuracy and is easy to attach and align. The track fully supports the saw, provides a smooth cutting action, and can produce a straight 4.375-in. deep cut while at the same time reducing operator fatigue. Saw requires 80 cfm of 90-psig air. It features a 3-hp pneumatic motor and uses 12-in. abrasive FRP blades that can cut stainless steel, Inconel®, ash pipe, and lined pipe. The steel track comes in 5-ft. sections and attaches using weld tabs.

Mettler-Toledo Thornton, Bedford, Mass, announced a new water calculator application for smart phones and mobile devices. The free application enables specialists to easily calculate conductivity, resistivity, and total dissolved solids conversions, flow and flow velocities, temperature versus resistivity and conductivity of ultrapure water, sample and process flow rate unit conversions, and temperature conversions between Centigrade and Fahrenheit.

Indeck Power Equipment Co's (Wheeling, Ill) new line of trailer-mounted O-Type rental boilers feature

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higher efficiency and greater reliability to meet institutional, utility, and industrial steam applications during planned outages or unexpected emergencies. The fleet includes units rated 40, 60, and 75 klb/hr at 395 psig. Boilers are designed for ease of delivery, install, and set-up. Piping is easily accessible and installation requires only a single electrical connection (Fig 11).

Swan Analytical USA's (Wheeling, Ill) AMI Analyzer Sodium P features a measurement range of 0.1–10,000 ppb for analyzing dissolved sodium in feedwater, steam, and condensate. It allows for continuous monitoring of sample flow and reagent addition and creates a reliable reagent delivery system with easy grab sample capability. With the elimination of unnecessary moving parts, the instrument is a complete, ready-to-use system that arrives factory-tested, calibrated, and mounted on a stainless steel panel. The programmable instrument is also available as a dual sample stream option.

E H Wachs, Lincolnshire, Ill, announces a new remote control for pneumatic machine tools. The Air Control Module (ACM), which needs no additional power sources, provides remote control operation of split frames or other pneumatic tools. Additionally, it allows operation from up to 26 ft away for enhanced comfort and safety (Fig 12).

ESCO Tool, Holliston, Mass, announces the portable Wart MILLHOG® right-angle, ID-clamping end-prep tool for preparing pipe for orbital welding in pipe fabrication and boiler maintenance applications. The tool can bevel, face, and bore simultaneously— including compound bevels and "J" preps—and provides consistent, contaminant-free end preps with torque-free performance (Fig 13). It operates over a 1.25 ID to 4.5 in. OD range with only six clamps and includes a robust gear drive supported by dual-opposed tapered roller


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bearings, a blade lock system, and TiN coated blades.

Commander MILLHOG® pipe milling and prep tool performs any angle of weld prep, including compound and multi-angle, on high-temperature/high-pressure heavy wall stainless steel, Super Duplex, P-91, and other hard alloy pipes. The tool features one mandrel and only seven sets of clamps for a full 3.75 in. ID to 14 in. OD range and pulls a thick chip without cutting oils. It is available with either pneumatic or hydraulic motors and includes dual-opposed tapered roller bearings and oversized clamps that spread the radial load for smoother welding end preps (Fig 14).


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Multifab Inc, Sharon Hill, Pa, has introduced the DNT Series M-Flex 600 pipe and duct connection material which uses a new style of PTFE capable of maintaining strength during continuous operation to 600F. The material can be used in wet or dry situations while maintaining zero porosity. It also offers extreme flexibility, a 6:1 compression ratio, and demonstrates excellent non-flammability properties.

Turbine Technology Services Corp's (Orlando, Fla) CMS-1000 monitors combustor dynamics in advanced-class gas turbines. The system, which can be portable or permanently installed, facilitates the optimization of a plant's combustion system while taking control of emissions.

Swift Filters Inc, Oakwood Village, Ohio, added to its website an interactive industrial filter element cross reference tool with 200 manufacturers and filter brands comprising over 59,000 entries. The tool allows users the ability to quickly find the filter replacement which is functionally and dimensionally interchangeable with any specific OEM filter.

GE Power & Water, Atlanta, has introduced a flexible fuel-blending technology for 7FAs that allows operators to use process gas to displace some natural gas. The new solution allows for the blending of up to 5% hydrogen in a DLN2.6 combustion system and enables operators to use hydrogen as part of the fuel mix.

People


Lesch

Joe Lesch, long a contributor to the **CCJ,** who retired as a VP of Chromalloy in January 2011 after 27 years of service, has opened his own shop, Lesch Consulting LLC. He is well known in the aero community for his knowledge of airfoil design, coatings, metallurgy, and engine overhaul. Less well known is that Lesch managed the O&M of Frame 7 assets for the first decade of his professional career. Contact him at josephalesch@att.net.

Gary D Keefe was appointed Johnson Matthey's regional sales manager for the Southeast, based in Atlanta; Charles F Salotti, regional sales manager for the Southwest, based in Houston.

Keefe

William (Will) Day was appointed VP/GM of the NAES Power Contractors office in Hillsboro, Ore. Day has over 30 years of experience in power generation, including leadership roles at NRG Energy and Cajun Electric Power Cooperative.

Will Zmyndak is the new director of operations at Chromalloy's Orangeburg (NY) advanced coatings and repair facility. He is a veteran of the aviation industry and has extensive experience with turbine airfoil coating and casting. Zmyndak will lead manufacturing activities at the plant, which will continue to focus on new protective barrier coatings for gas turbines.

Jesse Murray was appointed manager of plant engineering and technical services for NV Energy's Frank A Tracy Generating Station, located a few miles east of Reno, Nev.

Ron Shaver was recently appointed VP Operations at the Allied Power Group's Houston protective coatings, heat treatment, and compressor repair facility. Shaver will oversee day-to-day operations at the facility.

Alan Martin and Dan Baldwin, both boiler engineering and service experts, were hired to bolster HRST Inc's presence in the Gulf Coast area. Martin will be working out the Buna (Tex) office, Baldwin out of the Monroe (La) office.

Kurt Peninger joined Stellar Energy Systems as a division VP. He has 25 years of experience in the power industry, half of that at GE.

Mike Cook recently joined HIP LLC's Mechanical Field Services Group as technical services director. Most recently he was technical director at Wood Group's HIT Field Services.

Keith Brady, managing director of Rolls Wood Group, a 50-50 joint venture between Rolls-Royce plc and Wood Group, presented Modern Apprentice certificates to the first seven engineering apprentices to complete their four-year programs at the JV's new training center. The program combines classroom experience with on-the-job training, mentoring, and college-day release.

Company news

Siemens Energy plans to build a new combustion test center for gas turbines in Ludwigsfelde, about 10 miles south of Berlin. The investment of 66-million euros will allow the OEM to study and validate the combustion processes in gas turbines at its own test center. The goal is higher engine efficiency.

The company continues to expand its worldwide network of GT manufacturing facilities by investing more than $350 million in a new plant in Charlotte, creating 700 new jobs. The facility will supply countries with 60-Hz grids with gas and steam turbine/generators.

Allied Power Group, Houston, received certification from the International Standards Organization (ISO) for its quality system, which was established for repair of IGT components. The company's 85,000-ft^2 shop/office facility specializes in the repair of gas and steam turbine parts. It will be expanded by 32,000 ft^2 to accommodate compressor repairs, thermal spray coating, heat treatment, heavy mechanical department, and in-house metallurgical lab for coating qualification.

Structural Integrity Associates Inc, San Jose, Calif, acquired the Inspection Services Group of FBS Inc, State College, Pa, and entered into a strategic alliance with FBS to add new guided-wave technologies for nondestructive evaluation and/or structural health monitoring of piping systems and other critical components. A new Guided Wave Technology Center will be opened in State College to focus on the advancement and delivery of guided wave services for the energy industry.

NAES Corp and Fluitec International sign a preferred vendor agreement that will give NAES-operated plants the preferential services, scheduling priority, and cost concessions commensurate with the volume of business represented by the NAES-operated fleet. The solutions, products, and knowledge provided by Fluitec will allow NAES to optimize the performance of its lubricated assets across the fleet.

NAES announced a new project services team to the Turbine Services Div. The team, which includes industry veterans Russell James, Rob Broglio, Rick Stanford, and Debi Patrick, will provide new management, sales, proposal, and support expertise to the division.

Siemens AG acquired Dutch sister companies NEM BV and NEM Energy Services (NES), both specialists in HRSGs for combined-cycle powerplants. The acquisition enhances Siemen's position in the HRSG business and enables the company to expand capacities and bolster expertise for the future.

BASF announced that the Research and Development Council of New Jersey awarded a team of the company's catalyst inventors the 2011 Thomas Alva Edison Patent Award for outstanding environmental contributions. The patent covers an emissions treatment system that removes NO_x and particulate matter from diesel engine exhaust using a single component. The invention is an improvement over current technologies using two separate components because it saves space while also reducing weight and backpressure.

Air New Zealand Gas Turbines partnered with Consolidated Asset Management Services and Redwood

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II Operating Co LLC to form ANZGT Field Services, a new company that will offer improved services for customers in North America. Led by General Manager Frank Oldread, the company is operating out of a 20,000-ft^2 state-of-the-art facility in Bakersfield, Calif.

Southern Research Institute plans a new SCR test facility that will allow utilities and others to independently test and evaluate catalyst performance.

NORD-LOCK, Elk Grove Village, Ill, acquires Superbolt Inc (US) and P&S Vorspannssysteme AG (Switzerland). The acquisition groups together products designed for critical bolting applications used in heavy industry and moves NORD-LOCK toward its goal of being the undisputed global leader in secure bolting.

Contracts

Rolls-Royce was awarded a contract to supply Petrobras with 32 RB211 power generation packages for eight floating production, storage, and offloading vessels used for processing hydrocarbons and storing oil (Fig 15). The equipment is for deployment in the Lula oilfields in the Santos Basin off the coast of Brazil.

Wood Group GTS won a long-term mobilization support and O&M contract from the new Bayonne Energy Center LLC. Wood Group is working closely with the owner's EPC contractor and will assume full responsibility for the 512-MW generating plant once it is commissioned in spring 2012. The facility will have eight dual-fuel, rapid-start Rolls-Royce Trent 60 gas turbines.

Wood Group GTS was also awarded an $11 million, multi-year contract by Empresa de Generacion Electrica de Arequipa SA to supply combustion and hot-gas-path capital parts for two GE Frame 6B gas turbines at the 71-MW Central Termica Pisco powerplant. Included in the contract is a provision for operational and critical spares along with repair of capital parts.

A 12-yr contract to supply parts for 14 6Bs located at various sites in Oman has also been awarded to Wood Group GTS. Under the terms of the contract, Wood Group, will assist in modeling new parts demand fleet-wide thereby optimizing parts usage. The turbines are used in natural-gas extraction from established fields.

A contract to overhaul a Solar Taurus™ 60 gas turbine installed along the Shaanxi-Beijing pipeline has been awarded to Wood Group GTS by a major Chinese oil and gas producer.

A new parts order for GE 7EAs marks the first purchase by global gas and energy solutions provider Air Liquide from Wood Group GTS. The parts will be installed in Air Liquide's Baoyou Cogen facility in Texas and at a plant in Louisiana.

Dow Chemical Co USA has awarded a contract to Wood Group GTS for hot-gas-path components for an ABB 11D5 gas turbine located at the Plaquemine Chemical Plant in Southern Louisiana.

A contract valued at over $2.7 million was successfully completed with the fitting of Wood Group GTS hot-gas-path capital parts in a Formosa Plastics Corp 7EA gas turbine at Point Comfort, Tex, one of the largest petrochemical facilities in the nation.

Rolls Wood Group's gas turbine maintenance contract with the Shell UK Ltd was extended to 2015. The contract includes maintenance, repair, and overhaul services for 27 gas turbines operating on seven offshore platforms in the North Sea. The engines are in electric generation and gas compression service.

Innovative Steam Technologies (IST) was awarded three new power

generation contracts including the design and supply of two OTSG units for the Lansing (Mich) Board of Water & Light. The second contract is for the design and supply of an OTSG unit for Windsor Locks, Conn, to be installed at the Algonquin Cogeneration Power Plant. The third contract, for the design and supply of an OTSG for Acarsoy Enerji in Denizli, Turkey, will be installed at the Arcasoy Enerji combined-cycle plant and will recover exhaust heat from an LM6000.

Everest Sciences Corp was awarded a contract for an ECOCool™ turbine inlet cooling system for a Solar Taurus 60 turbine located at a pipeline compression facility in Wyoming. The client, a large, integrated natural gas company, will rely on the ECOCool unit to enable the gas turbine to produce more power at greater efficiency while reducing operating costs and increasing revenue.

Vogt Power International Inc, Louisville, has been tapped by Siemens AG to supply HRSGs and associated equipment for the Lakeside 2 generating facility located in Vineyard, Utah. Vogt Power will design and deliver two supplementary-fired triple-pressure reheat HRSGs for use behind Siemens SGT6-5000F gas turbines.

Vogt Power also announced it will supply HRSGs to the Siemens Energy Termozulia III project in La Canada de Urdaneta, Venezuela. Vogt Power will deliver two unfired triple-pressure HRSGs for use behind Siemens SGT6-5000F turbines. It will incorporate Vogt's SMART design which features a high level of pre-assembly—modules, casing, interconnecting piping, and some structural steel all in one box—thereby streamlining onsite construction.

The Electric Generating Authority of Thailand selected Vogt Power to supply HRSGs and associated equipment for two combined-cycle plants—one located in Ayutthaya and the other in Songhkla. The company will deliver two unfired triple-pressure level HRSGs with reheat for operation behind Siemens SGT6-5000F turbines.

Plant news

The Guadalupe Power Project, Marion, Tex, owned by MinnTex Power Holdings LLC, has contracted NAES Corp for O&M services. The plant has two 2 × 1 combined-cycle power blocks powered by F-class gas turbines and an extensive zero liquid discharge water/waste treatment facility.

West Deptford Energy, owned by LS Power Group, completed financing for the construction of a 738-MW natural-gas-fired combined-cycle plant in West Deptford Township, NJ. The project will utilize state-of-the-art turbine technology with advanced emission controls. Construction is to begin early in 2012.

Sentinel Energy Center, is now under construction in California. Co-owned by Competitive Power Ventures Inc, GE Energy Financial Services, and Diamond Generating Corp, the $900 million gas-fired 800-MW plant is located near Desert Hot Springs.

Thor Precision opens rotor hardware shop

Thor Precision Inc, Greenville, SC, guided by founding partner and industry veteran Paul Pelinsky (ppelinsky@thorprecision.com) opens a value-added service center for aftermarket rotor hardware. Focus is on bolting for GE frame gas turbines—3, 5 (single shaft and two-shaft), 6B, 7E, and 9E—including compressor, turbine, unit, and load-coupling sets.

The firm's leadership team has more than 80 years of experience in the manufacturing of rotor hardware. Consulting staff includes a hardware engineer/metallurgist. All parts are reverse-engineered from OEM originals to guarantee fit, form, and function. Specifications exceed OEM standards and components come with complete raw material and manufacturing lot traceability.

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