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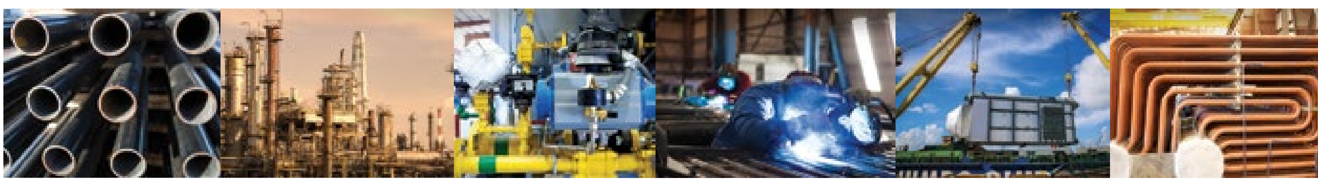
COMBINED CYCLE Journal

2016 OUTAGE HANDBOOK

Highlights

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR



Make user-group meetings a priority in conference planning

2015

November 4-5, Generator Users Group, First Annual Conference, Las Vegas, NV, NV Energy's Beltway Complex. Chairman: Kent Smith, kentn.smith@duke-energy.com. Details/registration at www.genusers.org. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

November 9-12, 7EA Users Group, Annual Conference and Exhibition, Santa Fe, NM, Santa Fe Convention Center. Details/registration at http://ge7ea.users-groups.com.

December 8-10, Australasian HRSG Users Group, 2015 Annual Conference, Novotel Sydney Central, Sydney, Australia. Chairman: Dr Barry Dooley, bdooley@structint.com. Details/registration at www.ahug.co.nz. Contact: Kirsten Pain, meetings@tmm.com.au.

2016

February 21-24, 501F Users Group, Annual Meeting, San Antonio, Tex, La Cantera Hill Country Resort. Chairman: Russ Snyder, russ.snyder@cleco.com. Details/registration at http://501f.users-groups.com when available. Contact: Caren Genovese, meeting coordinator, carengenovese@charter.net.

March 20-23, Western Turbine Users Inc, Palm Springs, Calif, Renaissance Hotel/Palm Springs Convention Center. Chairman: Chuck Casey, ccasey@riversideca.gov. Details/registration at www.wtui.com when available. Contact: Charlene Raaker, raaker.charlene@prodigy.net.

April 3-7, CTOTF Spring Conference & Trade Show, St. Augustine, Fla, Renaissance World Golf Village Resort. Chairman: Jack Borsch, jborsch@lakeworth.org. Details/registration at www.ctotf.org. Contact: Ivy Suter, ivysuter@gmail.com.

May 9-13, 7F Users Group, 2016 Conference & Vendor Fair, Orlando, Fla, Rosen Shingle Creek. Chairman: Ed Maggio, efmaggio@tecoenergy.com. Details/registration at www.7Fusers.org when available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

May 9-11, European HRSG Forum (EHF), Third Annual Meeting, Prague, Czech Republic, Courtyard by Marriott Prague Flora. Details at http://europeanhrsgforum.de/html/index.php when available. Chairman/contact: Ladislav Bursik, ladi.bursik@bht-gmbh.com.

June 6-9, 501D5-D5A Users, 20th Annual Conference & Vendor Fair, location/venue TBD. Chairman/contact: Gabe Fleck, gfleck@aeci.org. Details/registration at www.501d5-d5ausers.org when available.

June 13-16, Frame 6 Users Group, Annual Conference & Vendor Fair, Palm Beach Gardens, Fla, PGA National Resort. Co-chairmen: Jeff Gillis, william.j.gillis@exxonmobil.com, and Sam Moots, smoots@coloradoenergy.com. Details/registration when available at www.Frame6UsersGroup.org. Contact: Wickey Elmo, conference coordinator, wickey.elmo@frame6usersgroup.org.

June 20-23, V Users Group, 2016 Annual Conference, location/venue TBD. Contact: Kelly Lewis, conference coordinator, kelly.lewis@siemens.com.

July 24-28, Ovation Users' Group, 29th Annual Conference, Pittsburgh, Westin Convention Center Hotel. President, Executive Board: Wesley Whitley, wesleywhitley@alliantenergy.com. Register for membership (end users of Ovation and WDPF systems only) at www.ovationusers.com and follow website for details when available. Contact: Kathleen Garvey, kathleen.garvey@emerson.com.

August 22-25, Combined Cycle Users Group (CCUG), 2016 Conference and Discussion Forum, San Antonio, Tex, La Cantera Hill Country Resort. Meeting is co-located with the Steam Turbine Users Group and Generator Users Group; some joint functions, including meals and vendor fair. Chairman: Steve Royall, sgr8@pge.com. Details at www.powerusers.org when available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

August 22-25, Steam Turbine Users Group (STUG), 2016 Conference and Vendor Fair, San Antonio, Tex, La Cantera Hill Country Resort. Meeting is co-located with the Combined Cycle Users Group and Generator Users Group; some joint functions, including meals and vendor fair. Chairman: Bert Norfleet, bert.norfleet@dom.com. Details at www.powerusers.org when available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

August 22-25, Generator Users Group (GUG), 2016 Conference and Vendor Fair, San Antonio, Tex, La Cantera Hill Country Resort. Meeting is co-located with the Combined Cycle Users Group and Steam Turbine Users Group; some joint functions, including meals and vendor fair. Chairman: Kent Smith, kentn.smith@duke-energy.com. Details at www.powerusers.org when available. Contact: Sheila Vashi at sheila.vashi@sv-events.net.

September 11-15, CTOTF Fall Conference & Trade Show, Rancho Mirage, Calif, Westin Mission Hills Golf Resort & Spa. Chairman: Jack Borsch, jborsch@lakeworth.org. Details/registration at www.ctotf.org when available. Contact: Ivy Suter, ivysuter@gmail.com.

To be decided

Dates, location, and venue are not yet available for the 2016 mid-year meeting of the 501D5-D5A Users (http://501d5-d5ausers.org), and the 2016 annual meetings of the T3000 Users Group, ACC Users Group (www.acc-usersgroup.org), 7EA Users Group (http://ge7ea.users-groups.com), and Australasian HRSG Users Group (www.ahug.co.nz).

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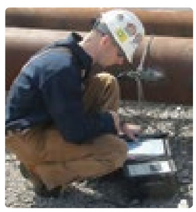

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Review these TILs before writing your next 7FA borescope specification

Mike Hoogsteden, field service manager for Advanced Turbine Support LLC (QR 1), speaking at the 2015 meeting of the 7F Users Group in Denver, May 11-15, encouraged owner/operators to read all applicable Technical Information Letters (TILs) issued by the OEM before developing their next specification for a 7FA borescope inspection.

He began his presentation with these introductory remarks: "There are many variables in gas turbines that can be monitored to warn of impending component failure—such as vibration, temperature spreads, etc.

"However, relying exclusively on operating data for early warning increases the likelihood that problems will go undetected until damage occurs. Routine inspections by technicians with detailed knowledge of engine internals and equipped with the latest non-destructive examination (NDE) tools are considered by many to be your first line of defense against catastrophic damage."

QR 1

QR 2

TILs 1796 and 1870-R1. What better place to begin than at the beginning—of the compressor, at R0. Forward migration of R0 blades has been a concern for several years (Fig 1). Undersized stake marks are the primary issue. TIL 1796 (Apr 25, 2011) offered guidance on how to determine if blades are properly staked and the steps necessary to correct if need be (QR 2).

TIL 1870-R1 (Mar 5, 2013) followed, requiring owner/operators to check for first-row blade migration on F-class compressors that received an R0 reinstallation between January 2008 and January 2013. A small population of turbines reportedly suffered migration events related to improper blade installation.

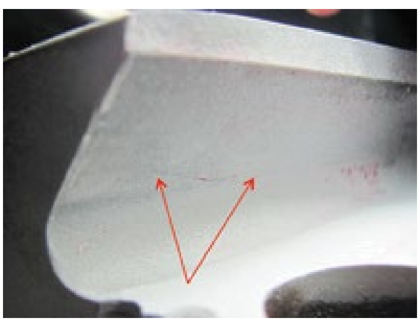
Hoogsteden stopped at this point to explain why he was spending so much time reviewing "old stuff" and would continue to do so throughout his presentation. The simple fact is Advanced Turbine Support's inspectors are still finding problems that have been discussed for years. Reasons for this include virtually continuous turnover in the staffing at some plants and in the ownership of those facilities. During such churn, TILs and previous inspection reports go missing and new people may not have the background required to specify an experience-based scope of work for upcoming borescope inspections.

Biscuit rotation was the next

1. Forward migration of R0 compressor blades is conducive to leading-edge platform damage

2. TIL 1870 provides guidance on biscuit inspection and steps to take if rotation is identified as shown in photo

3. Biscuits can be inspected by drilling a hole in the rub ring just large enough to accommodate a borescope probe



4. Crack in a R0 dovetail slot of the forward stub shaft is validated by red dye

5, 6. Radial tip cracks (left) can propagate and in extreme cases allow a portion of the airfoil to liberate (right)

7. In-situ blending can eliminate cracks and avoid metal liberation and downstream damage

8. Trailing-edge crack at the platform of an S0 vane in a flared compressor

topic—logical because it typically is caused by improper staking. Guidance on inspection and steps to take if biscuit rotation is identified also is provided by TIL 1870-R1 referenced above (Fig 2). Hoogsteden showed attendees the way Advanced Turbine Support technicians can inspect biscuits from the air inlet side of the compressor by drilling a small hole (less than ¼ in. diam) in the rub ring to accommodate a borescope probe (Fig 3).

TIL 1907 was issued Oct 7, 2013 to alert 7F users to the risk of cracking in the dovetail region of the forward stub shaft (Fig 4) and to define inspection scope and intervals for specific unflared and flared configurations (QR 3). Cracks in the region of interest can be hidden from view and the risk of not conducting a proper in-situ UT inspection *at least annually* is that the disc theoretically could fail before a crack is seen.

QR 3

To date, Advanced Turbine Support inspectors have identified R0 rotor wheel cracks in five 7FAs. One confirmed unit with cracks exhibited crack growth of approximately one-half inch in a 12-month period. Hoogsteden presented a couple of pictures to show attendees what these cracks look like. Members of the 7F Users Group can access the presentation through the organization's website (QR 4).

QR 4

TIL 1509-R3, "F-Class Front-End (R0, S0, and R1) Compressor Inspections," covers a lot of territory. Here are the highlights (QR 5):

QR 5

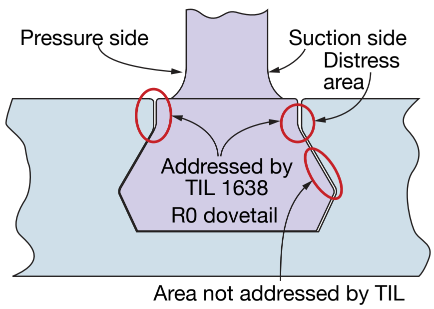
QR 6

- R0 leading-edge distress, which can be caused by impact damage; root-area erosion by fogging and/or the introduction of corrosive elements into the compressor inlet (QR 6).
- R0 and R1 blade-tip cracking, which is caused most commonly by tip rubs against the case during operation (Figs 5-7).
- S0 stator-vane trailing-edge cracks (Fig 8), which apparently are caused by vane "lock-up." The speaker noted that his company's technicians have identified, with eddy current, both S0 and S1 stator-vane cracks in the initiation phase that measured less than 0.08 in. (Fig 9). These indications were not identified visually, even after being inspected with fluorescent dye.

Hoogsteden once again showed several photos of the different types of damage covered by this TIL. They are accessible by 7F owner/operators on the users group website.

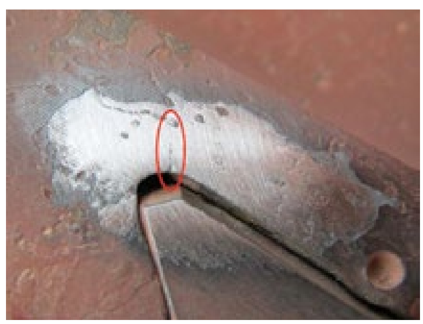
TIL 1638 (May 13, 2009), "F-Class R0/R1 Platform Ultrasonic Testing," applies to gas turbines with rotating Stage 0 blades that do not have the platform undercut feature. Its purpose is to advise users of in-situ R0 and case-off R1 testing recom-

9. Trailing-edge crack is within 1½ in. of the tip of an S0 vane in an unflared compressor (left). If the crack is not detected during an inspection, the tip could liberate (right)



10. Distress areas identified in TIL 1638 plus another found by technicians from Advanced Turbine Support that users should be aware of

11. Clashing damage is in evidence on trailing edge of R3 rotor blade (left) and on the leading edge of an S3 stator vane (right)



12. Dovetail crack is on the trailing edge of an R17 airfoil

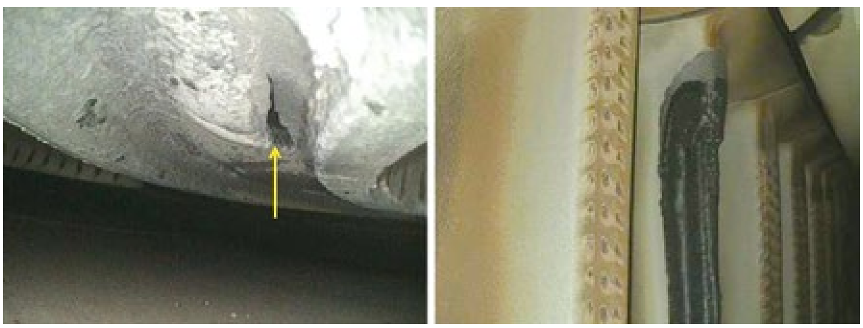
13. Mounting hardware fails on R17 stator vane and moves forward (direction of arrow), contacting the trailing edge of R17 airfoil

14. Combustion inspection shows cracks in the mounting bracket for original 12k transition piece (left). Cracking problem was transferred to the impingement sleeve in replacement 24k hardware (right)

15. Effusion plate cracking is something else technicians look for during combustion inspections

16. Collar for crossfire tube liberated and the tube dropped out. This also was found during a combustion inspection

17. Turbine inspection revealed crack in first-stage bucket platform (left). If not repaired, material loss shown at right could occur



18. Damage to first-stage bucket tip cap (left, photo taken looking up at the bucket from below) must be found and addressed to prevent cooling-air starvation and damage at right

mendations to ensure against the presence of dovetail distress below the blade platform (Fig 10, QR 7).

QR 7

Hoogsteden said that since 2007, Advanced Turbine Support has completed in-situ more than 2200 inspections (P-cut, standard, and enhanced blades) and in the process has identified the following:

- 55 cracked R0 blades adjacent to the P-Cut relief.
- 57 cracked R0 blades in the suction-side mid-span dovetail fillet.
- Three cracked R0 blades on the suction-side mid-span dovetail sloped face.
- Two cracked R0 blades in the pressure-side dovetail fillet (both in the leading and trailing edges).
- Three cracked R1 rotor blades in flared units.

Clashing between R2/S2 and R3/S3 airfoils has been identified in both the upper and lower halves of 7FA compressors (Fig 11). Hoogsteden, who has closely followed clashing incidents in the 7EA fleet for years, often presenting on the subject, said he knows of nine cases of 7FA clashing; two of those units had damage so severe forced outages were necessary (QR 8). The OEM has not yet released a TIL on 7FA clashing.

TILs 1971 and 1972. Cracking in R17 wheel dovetail slots also was mentioned. The Advanced Turbine Support field service manager suggested that 7FA owner/operators specify annual inspections of the rotor dovetails at the trailing edge of R17 (Fig 12, QR 9). If cracks are identified, safe operating practice suggests not to run the unit until an engineering disposition can be performed. If cracking in the dovetails goes undetected, a possible result is blade liberation and significant damage (QR 10).

QR 8

"F-Class Shrouded Stator 17 Inspection," covered by TIL 1850 (Aug 20, 2012), advises owner/operators to monitor the shrouded S17 design and provides recommendations for mitigating any observed distress. The photos Hoogsteden showed—such as failure of mounting hardware, rotor contact caused by shroud movement (Fig 13), etc, were similar to the illustrations found in the TIL.

QR 9

Hoogsteden wrapped up his presentation to the packed meeting room with a series of photos from

19. Tip shroud liberation from second-stage bucket is addressed by TILs 1858, 1859, and 1863

20. Liberated flex-seal and ring pipe material (above) damaged third-stage buckets (below)

recent inspections by Advanced Turbine Support technicians to familiarize 7FA plant personnel with some of the damage others have found and why it's important to inspect gas turbines regularly. Here are some of the images you can view in the speaker's PowerPoint, available to owner/operators at www.7fusers.org:

QR 10

- Combustion inspection: cracks in mounting brackets for transition pieces (Fig 14), impingement sleeves, and effusion plates (Fig 15); damage to PM2 fuel nozzles and cross-fire tubes (Fig 16).
- Turbine inspection: first-stage nozzle damage and measurements; first-stage bucket platform cracks and material loss (Fig 17) as well as tip-cap damage and material loss (Fig 18); cracking of the second-stage bucket tip shroud (Fig 19); liberated flex-seal ring-pipe material and exposed flex seal and resulting third-stage bucket damage (Fig 20). CCJ

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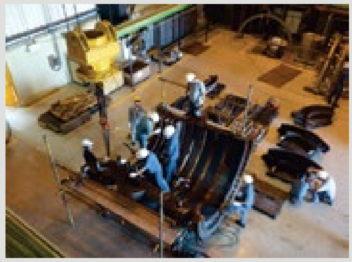
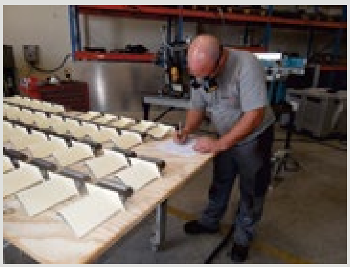

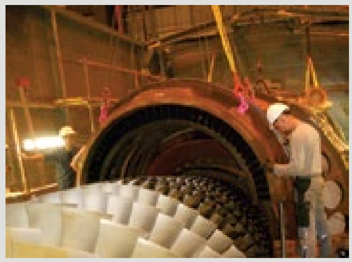
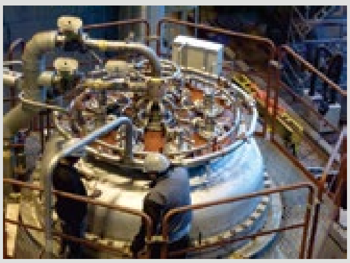

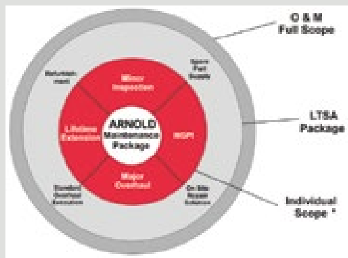

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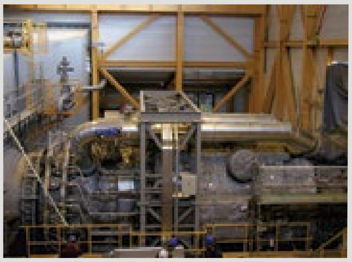

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Two owners weigh in on pros, cons of robotic inspection

By Patricia Irwin, PE, Consulting Editor

Deciding whether to robotically inspect a generator is a big decision. One reason is cost: It's expensive, typically running more than six figures. Another is accessibility: Only certain types of generators have air gaps large enough to allow robot access. Yet another: You might not get all the information you want.

However, robotic inspections do provide some useful information and they take only three or four days to complete (photos). This is much less time than required to pull the field, conduct an inspection, and replace the rotor—and without exposing the generator to the possibility of damage during handling.

How would you decide between robotic or manual inspection? CCJ asked two plant owners, in very different situations, this question, and their answers were inconclusive: Robotic inspections can be useful, in certain cases, the editors were told. Careful evaluation of your particular situation will determine the best way to proceed.

Limited clearance can make it challenging to get a robot into a generator. For some machines, the gap is too small for any robot to gain access

Once inside, the robot proceeds down the length of the core. The attached cable relays visual and/or testing information back to the operator

Duke Energy

Duke owns and operates more than 350 generators. With that number of machines, Kent Smith, manager of generation engineering, put a great deal of thought into whether Duke should buy its own robot.

There are several suitable robots on the market, he said, ranging in height from half an inch to two inches. They typically are 6 in. wide and about a foot long. Each has a drive mechanism, which takes up the majority of the available space on the device, and some magnetic properties, so the robot can hold itself to the top of the core. Different sensors and modules are attached to perform specific tests.

Smith evaluated several devices and found that size does matter. "Robots can only be used in certain types of machines because of the narrow air gap. That is true even for OEM robots on their own generators. For example, the Siemens robot can't inspect all Siemens machines," explains Smith. "So, we evaluated about 160 of our machines and determined how many we could inspect robotically. The answer was only about 10% and we decided it really wasn't worth the effort or money to buy our own robot."

But Duke does hire OEMs to inspect some of the generators that fall into the 10%. For example, Siemens robotically inspects its Aeropacs and, on one occasion, Duke hired GE to use its Miniature Air Gap Inspection Crawler (Magic) system on one of its machines.

Smith explains, "We don't tend to robotically inspect our large GE machines because they have air baffles. Basically, the air baffle is a rubber insert, perpendicular to the length of the core, which goes 80% of the way around the core. There can be eight or 10 baffles down the length of the stator core. So, you have this small space down at the bottom of the core, near the skid plate, to get the robot out. To see anything else you have to run the robot down to the skid plate and then try to run it back up the side. And, the robots just don't move that way."

Types of tests. Assuming the robot fits inside the air gap, there are other things to consider before scheduling an inspection. "Decide what you want tested and if the robot will give you the kind of results you need. For example, you can test wedge tightness with a 'tapping' module, you can do an Electromagnetic Core Imperfection Detection (El CID) test, and you can perform a visual inspection. But, at Duke, we are going back to running loop tests on our cores and you can't do that with a robot. So, if we are going to pull the field anyway, why spend the $100,000 for a robotic inspection?"

Missed spots. Since the robot cannot reach everywhere, spots will be missed during the inspection. Smith continues, "The robot doesn't do a good job on the step iron. To get into the core, it has to get past the step iron and it can't read the step iron very well. So, if you want to run an El CID at the step iron, you have to do it manually."

Sticking point. And, while rare, Smith is concerned the robot could get stuck. "We haven't had a problem but we have heard of it happening. And, we heard the vendor had to do some 'unique manipulations,' but was able to get the robot out without having to pull the field."

Wrap-up. Despite the limitations, Duke decided to continue robotic inspections on appropriate generators for general inspection. "With robotic inspections, there is less disassembly and less risk. Does it give you a complete picture of the health of the machine? No. But, it is a lot better than a normal crawl-through inspection," says Smith.

He continues, "I am a proponent of having more tools in the toolbox. Nothing can be used 100% of the time and give you a 100% confidence level on the health of the machine, so you need to have as many tools as possible at your disposal. Robotic inspections are one more tool."

Griffith Energy

Compared to Duke, Star West Generation LLC is a much smaller operation, owning only five powerplants. Mike Hartsig, plant manager for the company's Griffith Energy, has a 2 × 1 F-class combined cycle equipped with two GE 7FH2 generators for the gas turbines and a Toshiba generator for the steam turbine.

View of robot from inside the generator

Hartsig notes, "In 2012, we had a contractor to do some partial-discharge testing our generators. Conclusion was that we should take a look at the two 7FH2 generators, especially the wedges. We had a four-week outage coming up, so we had time to pull the rotors and physically check the wedges, if we choose to. Our other option was to check the wedges robotically, which we had done in the past."

In 2005, the plant hired GE to perform robotic inspections on those units and Hartsig decided to use robots again to avoid the risks associated with pulling the rotor. This time around (2013), the plant manager got quotes from various vendors and settled on an experienced vendor, other than GE, to perform the inspection.

After testing, the vendor prepared wedge maps for both machines. The color coded maps showed significant wedge looseness, particularly on Unit 2. Vendor engineers recommended a total re-wedge, but Hartsig was not sure.

Contradictory results. "Both machines had been inspected by GE in 2005. So, I had GE come back in with the Magic system and do a sample wedge tightness test on Unit 2. The results? No problem at all. Then, I compared the latest GE results with previous results. In 2005, GE said that the generator looked good but one wedge was questionable. According to the new test, that wedge was no longer a problem," says Hartsig.

At this point, Hartsig and his team reconsidered the value of robotic testing. "We looked at our original premise and, after much discussion, concluded that our original premise was sound. Even though the results raised a lot of questions, we avoided the risks of pulling the rotor and we still felt comfortable in our decision to do the testing."

Decide what to do. Griffith Energy brought in independent experts to review all of the wedge-tightness test results. They concluded there was no significant problem. "This was based on their experience and knowledge of wedging in generators. The experts pointed out that, even if a wedge came loose, which was unlikely based on collected data, the worst-case scenario was some arcing between stator bars. And according to the experts, you can run a generator for a prolonged period of time with a shorted bar, although this is not recommended. The general conclusion was to monitor key indicators and wait until 2018 to go into the units," explains Hartsig.

Conclusion. Hartsig continues to recommend robotic inspections, with a few caveats. "Why do a robotic inspection if you get a contradictory results and you don't do anything with them? I think those results pushed me to the next level. My advice is to go in with your eyes open. Get the results and compare them to other data you've collected. Then make the hard decisions for yourself."

Hartsig also recommends relying on industry experts who will not gain anything by recommending you wait before doing remediation work. "A larger company will have a massive back office with its own experts and engineers. We don't, so we go to outside contractors. And, I don't take the word of one contractor, I get a second or third opinion. Then, based on that, we move forward."

"I still favor robotic inspections for one simple reason: The risk of damage is slim to none. The risk of damage from pulling the rotor is greater. That is not to say that every time you pull the rotor you're going to do damage, but the risk is always there," concludes Hartsig. CCJ

Microgrid office

This microgrid is not located on an island, a sequestered military site, or in a state with incentives for distributed energy. And it's not serving a tech or clean/green stock darling of Wall Street with an amped-up market value seeking to remake the electricity industry in its own image.

Rather, it's an advanced microgrid serving the world headquarters of Black & Veatch in Overland Park, Kan. B&V, one of the industry's venerable engineering, procurement, and construction (EPC) companies is helping to pave the way for further microgrid deployment.

The term microgrid has been around for at least 15 years. Like so many buzzy phrases before it—clean coal, smart grid, distributed power, clean tech—its definition is tough to pin down. **CCJ** defines it as a set of generating assets with diverse energy resources operated in an integrated fashion to serve the electrical and thermal-energy needs of a building, a campus, a cluster of commercial buildings, a town, or a neighborhood as a supplement to, and typically in parallel with, a utility grid.

These systems can enhance resiliency and sustainability, or make energy costs more predictable; whether for those in the utility system or located in island or remote regions with limited or no connection to the grid. The diversity and integration of the assets in Black & Veatch's microgrid are perhaps the most striking:

- Two 65-kW gas-fired micro-turbine/generators, equipped with recuperators to capture exhaust heat and raise turbine efficiency. Turbine exhaust heat is also used to heat water for the building HVAC system (Fig 1).

1. Micro-turbine/generators, gas-fired, have recuperators to capture exhaust heat for improving engine efficiency and heating water

- 50-kW of rooftop solar PV panels split equally between two wings of the company's innovation pavilion. A string of micro-inverters manages the DC-AC interface (Fig 2).
- 100-kW lithium-ion battery energy storage system (BESS) to shave peak load, manage voltage and frequency response of the variable output solar PV, provide backup power in the event of emergencies, and others ensure that building electrical demand is met under virtually all but the most extreme outage conditions (Fig 3).
- Forty-five electric vehicle charging stations, two installed in 2011, seven new ones as part of the microgrid, and 36 in partnership with a local utility (Fig 4).
- Liquid extraction from a geothermal resource beneath the campus to improve overall HVAC efficiency and keep walkways free of ice in winter (Fig 5).

Other important features include islanding capability from the utility grid in the event of a utility power outage and the application of B&V's home-grown energy management system and software based on the company's Asset 360 cloud-based analytics platform. The microgrid, which can produce around 1300 MWh annually, was commissioned at the end of April 2015.

"Each individual piece of the system, and the system as a whole, is monitored 24/7/365 so we can gain insights

2. Rooftop solar PV system is rated 50 kW (left)

3. Energy storage is provided by a 100-kV lithium battery system. It helps shave load peaks (above)

4. Electric-vehicle charging stations at Black & Veatch's offices number 45 (left)

5. Geothermal energy helps improve overall HVAC efficiency and keeps walkways free of ice in winter (below)

into operations and how to improve performance," said Jason Abiecunas, project manager and microgrid business lead for Black & Veatch. "Real time and historical data are displayed at interactive touch screens in our Innovation Pavilion, along with usage profiles for the east and west wings, and floor by floor."

"It's important for us to be leaders in continued technology evolution," continued Abiecunas, "microgrids aren't going to replace the prevalent utility industry infrastructure, but building and operating our own microgrid better prepares us to provide new services to our traditional utility clients and other emerging owner/operators of localized electricity infrastructure."

Microgrids are receiving added attention these days because of another buzz word issue—resiliency. Some industry observers theorize that a distributed architecture for power generation and delivery may someday be more reliable than the traditional "big iron" centralized approach, prone to high-profile outages from weather and other catastrophic events that appear to be on the rise (sidebar).

But the big-iron approach is, generally, so reliable that the average customer experiences only one to two hours with no electricity a year. Reliability is different from power quality, though, and power quality is the more important metric in today's world of digital everything.

The combination of centralized and decentralized models may create the best resiliency scenario. CCJ

Microgrids predate the central-station model

Microgrid may be a new word in your vocabulary, but it's certainly not a new idea. There were hundreds of thousands of microgrids operating in the US about the time of the Great Depression, before the benefits of integrating large central stations, high-voltage transmission lines, and distribution systems into an electric system were made available nationwide by the Rural Electrification Administration (REA).

For microgrids in the US, this latest "fling" with the technology is not driven by need, as it was in the early 1900s, but by the idea that the power quality will be better, the reliability of energy supply will be higher, the cost of energy will be lower, etc. The jury is still out. As with most everything else, microgrids will be a positive in some instances, a marginal solution in others. Industry grey heads may remember the "total energy" movement of the late 1960s and early 1970s; it fizzled when utilities reduced the price of energy to large customers and owners faced the realities of O&M staffing and the cost of upkeep.

Sure, microgrid technology is much more advanced today than it was in the 1920s, 1930s, and 1940s when Delco-Light and similar systems dominated the market. But the technologies used to generate bulk power today also are much more efficient, premium fuel is readily available at affordable cost (in the US, at least), and reliability of electric supply likely never has been better. Do your homework before making a big-dollar commitment.

The editors spoke with two industry seniors born into farm families about what life was like before the REA distribution lines got to their homesteads. Clyde Maughan, president, Maughan Generator Consultants, who just turned 89, recalled his experiences (including a gasoline fire) with the Delco-Light unit on the family's Idaho farm. "Limited capability," he said.

Rodger Anderson of DRS Technologies, perhaps best known industry-wide for his vane pinning solution to lock in place airfoils in GE frames, hails from Minnesota. REA distribution lines got to his family's farm in 1949. He remembers their Delco-Light system well. It differed from Maughan's in that the engine started automatically when battery voltage dropped to a given level; the Maughan engine was manual start/stop.

Marshall, the closest city (population about 4000 in the early 1940s) to the Anderson farm had a municipal microgrid, with heat recovered during the production of electricity also delivered to customers via a downtown thermal loop. Seems everything old is new again.

In case you're thinking renewables is one of the big differences between these ancient microgrids and today's, guess again. Anderson said the farm next to theirs was powered by a Jacobs Wind Energy System. Consider taking a few minutes to trace the history of microgrids. Simply scan the QR code with your smartphone or tablet to gain a valuable perspective.

How to test, maintain 7EA IGVs, auxiliaries for top performance

Dave Lucier, founder/GM of PAL Turbine Services LLC, was the featured speaker from the opening bell to morning coffee on Day Two of the 7EA User Group's 2014 Conference. A former GE field engineer, who later instructed and managed the mechanical training of future field engineers (QR 1), Lucier shared his knowledge on the servicing and change-out of inlet guide vanes *with the rotor in-situ,* and on the maintenance of auxiliary systems.

QR 1

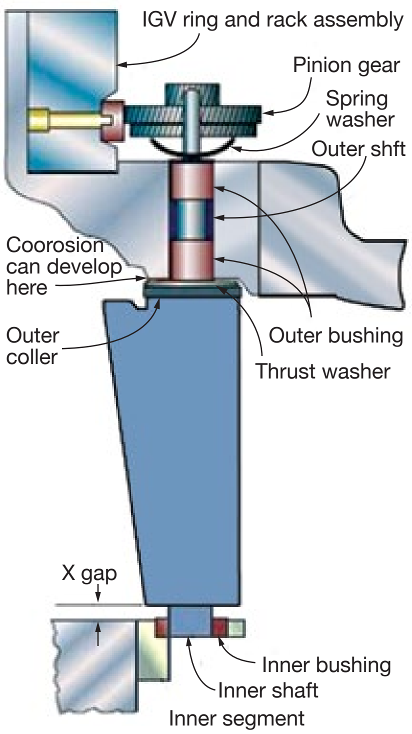
He credited his former partner, Charlie Pond, recently deceased, for the significant cost-saving maintenance techniques described in the IGV segment of the presentation. Pond was well-known to 7B-EA, 6B, and Frame 5 owner/operators for his field work and user-group presentations.

Inlet guide vanes

With many first-timers among the 136 registered users, Lucier began "at the beginning," telling attendees variable IGVs had the following purpose:

- Prevent compressor stalls during startup.
- Modulate air flow at partial load to maximize exhaust temperature on units in combined-cycle and cogeneration service.

He urged O&M personnel to inspect IGVs regularly and replace those components not operating properly, and to upgrade airfoils on ageing machines to improve performance. Example: The C-450 material used for vanes today is stronger than yesterday's Type 316 and 403 stainless steels, allowing a slimmer airfoil and more air flow through the machine. Common problems with IGVs include frozen bushings, broken shafts, worn bushings, and excessive gear backlash.



1. Knowing how the essential mechanical elements of variable inlet guide vanes go together and work is essential for good maintenance

Regarding frozen bushings, Lucier said it is not surprising to find one or more IGV shafts seized in their bushings on ageing outdoor machines. Legacy bushings, he continued, were steel and susceptible to corrosion and binding. More recent GE turbines have Teflon®-coated outer bushings and Chemloy bushings on the inner diameter (Fig 1). But keep in mind that while Chemloy bushings are much softer than steel, and never bind, they do wear out much faster.

IGV shafts can break at the pinion gear on machines suffering severe corrosion. If this happens at your plant, take immediate corrective action. Be aware that when a shaft breaks, the IGV generally reverts to the closed position, which is conducive to high-cycle fatigue of first-stage compressor rotor blades. Failure of an airfoil can cause catastrophic downstream damage.

Rack-and-pinion gears suffer wear and tear over the years and must be checked for excessive backlash (Fig 2). Lucier said 40 mils is the maximum backlash allowed; maintenance personnel should shim rack gear for 5-10 mils of clearance.

The speaker then reviewed the

2. Rack-and-pinion gears should be checked for excessive backlash at least annually (left)

3. Lower four vanes are shown with staked dowels and cap screws (right)

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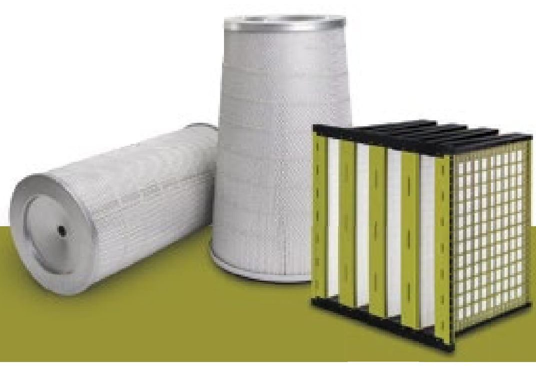

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CLARCORindustrialair.com | +1-800-821-2222 | +44 (0) 1420 541188 technique developed by Pond to service or replace vanes in the lower half of the engine (Fig 3) without removing the rotor. This had been described at a user group meeting several years ago (QR 2). In closing, he suggested O&M personnel become familiar with the following Technical Information Letters to assure proper inspection and maintenance: 421, 511, 515, 517, 522, 532, 1013, 1041, 1068, and 1132.

QR 2

Auxiliary systems

A common thread linking Lucier's presentations was the value of well-trained OEM field engineers to owner/operators. The speaker, mindful of the challenges facing O&M personnel new to the ageing 7EA fleet, walked the group through lessons learned and best practices, several documented on his company's website.

Lucier began by saluting field engineers for their problem-solving abilities and linking their efforts to the fleet's solid performance over the years. Judging from facial expressions, it came as a surprise to many in the room that critical parts of legacy units were made at different facilities and first met at the job site, where FEs were charged with assembling the units. He said the gas turbines were made in Greenville, SC; generators in Schenectady, NY; control cabs in Salem, Va; and the generator auxiliary cabs in Chamblee, Ga (Fig 4).

Also noteworthy: Factory testing was done on oil and full-power tests actually were conducted at about two-thirds of rated output because the turbine was driving its own compressor, albeit it not connected to a generator in the factory. That meant field engineers also were responsible for achieving contractual requirements and fulfilling the owner's expectations. Theirs was an awesome responsibility, Lucier said.

Next, he asked, and answered, the following questions to illustrate the importance of auxiliaries to unit *availability* (the ability to start and operate when expected) and *reliability* (the ability to achieve base rated load when called upon):

4. The 7EA fleet is ageing. Here's what an MS7001 packaged powerplant looked like about 25 years ago

5. Motor control centers, often overlooked in equipment assessments, require ongoing attention (left)

1. What is the *most expensive* part of a gas turbine? Most would say the rotor.
2. What would you say is the *least expensive* part of a GE gas turbine? Difficult to say.
3. What is the least expensive part, that if you needed one and didn't have a spare, you learned it is no longer available to purchase and you can't make one?

Lucier paused after the third question and asked attendees to think about it for a moment. Then, he said, "Chances are, a serious problem with a component in an auxiliary system will prevent the GT from starting, or initiate an emergency shutdown." Startup challenges likely will occur during firing/flame/warmup and when ramping to base load, Lucier noted.

Electrical and controls equipment were at the top of the speaker's list.

6. Motor starters are heavy-duty and reliable but need regular servicing. Shown here is a reconditioned starter with LED lighting and new contacts

7. Individual battery cells comprising a 125-V DC system are numbered

Pictured above from left to right: Chris Schroh, Terry MacKinnon (both from Esterline), Randy Lincoln and Ronnie Hazlewood (both from MTS, Inc.).

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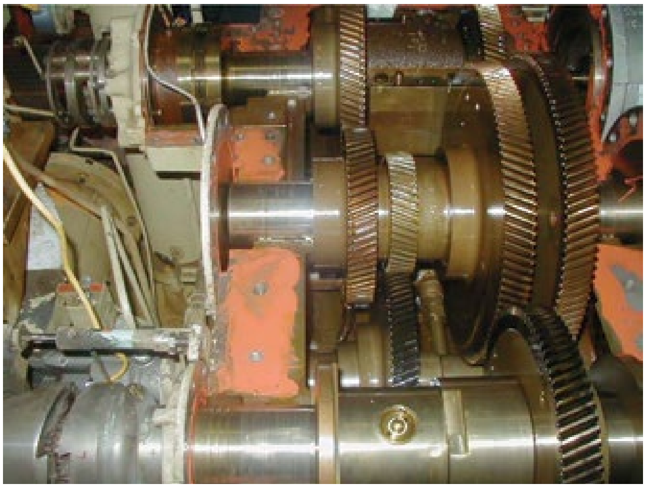


8. Components of a typical accessory gearbox are exposed with the cover off

9. Condition and alignment of a jaw clutch must be checked; don't hesitate to replace when wear and tear is significant.

Motor control centers (Fig 5), often overlooked in equipment assessments, require ongoing attention, he said, because they control the fluid systems critical to engine operation—including lube and hydraulic fluids; fuels (oil and/or natural gas), cooling and injection water; atomizing, cooling, and sealing air, fire protection, etc.

Lucier said GE motor starters (Fig 6) are heavy-duty and reliable, but they still need regular servicing. He stressed that plant startup hinges on DC motor-driven pumps. Gear drives may take over when the unit is up and running, the speaker continued, but achieving high starting reliability demands that motors run when required. He showed photos of equipment that was past-due for maintenance and how careless personnel had mistreated junction boxes.

Servicing of battery cells and charger for emergency DC power were the next topic (Fig 7). Maintenance practices published previously offer details (QR 3); a more recent post addressed NERC's proposed requirements for station batteries to assure grid reliability (QR 4).

Referring to transducers and sensors, Lucier said, "Don't assume these things will last forever." He urged users to (1) have a lab periodically test pressure transducers, (2) send servos to the manufacturer for regular maintenance, (3) stroke test LVDT position feedback sensors, and (4) verify the operability of fire sensors in both the accessory and turbine compartments, speed pickups, flame detectors, and vibration sensors.

QR 3

QR 4

The auxiliaries' "action items" checklist presented next was a "keeper" for most attendees. It is of particular value in outage planning. Here are the highlights:

10. SSS clutch replaced original jaw clutch

11. Lube-oil pump is removed for servicing

12. Lube-oil-cooler tube bundle should be removed periodically for condition assessment and cleaning

- **Accessory gearbox** (Fig 8). Recall that during normal unit operation gears drive pumps supplying lube oil, hydraulic fluid, and water. Suggested action plan: (1) Remove accessory-gear cover; (2) Inspect gears, bearings, and seals; (3) Inspect lube-oil, hydraulic-fluid, and water pumps; (4) Check for proper gear contact and shaft alignment.
- **Jaw clutch.** Jaws wear out over time, particularly on peaking engines. During your maintenance outage, inspect the jaw clutch (Fig 9) and check its alignment to the starting device. When replacement is necessary, consider a SSS clutch or equivalent (Fig 10).
- **Lube-oil pumps** (Fig 11). Inspect and test all motor-starter circuits and interlocks for both the AC and DC pumps. Check coupling between the pumps and their motor drivers. Verify pump/motor shaft alignment and replace the intermediate coupling.
- **Hydraulic supply pump.** Inspect and test the motor starter circuit; check the coupling between pump and motor; verify alignment and replace the intermediate coupling.
- **Lube-oil cooler.** Remove the tube bundle periodically for flushing and maintenance (Fig 12). Specify a pressure test prior to reinstalling the tube bundle.
- **Package radiators.** Remove radiator sections for flushing and pressure test (Fig 13). Reinstall radiators and conduct a leak-check (Fig 14).
- **Buffalo water pump.** Remove to inspect impeller and replace seals.
- **Atomizing-air compressor.** Remove the gear-driven atomizing-air compressor, disassemble the unit and inspect impeller and seals.
- **Cranking motor** and torque converter. Megger test the motor, inspect the torque converter and

13, 14. Radiators must be flushed and pressure-tested regularly (left); clean radiators ready for installation are at right

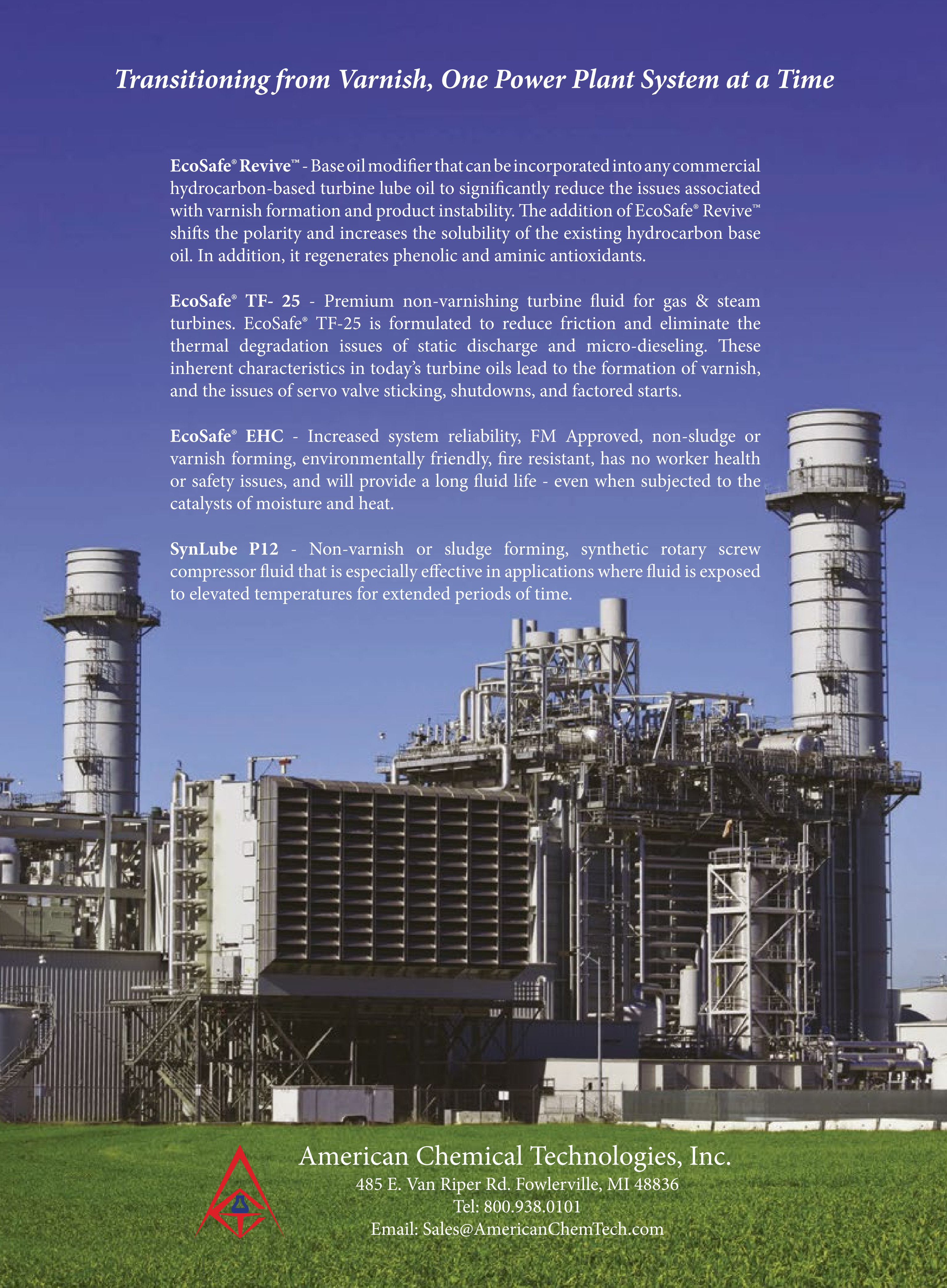
15. Test solenoid valve (black) to verify the stop/ratio valve will close on loss of trip-oil pressure

16. Actuate the liquid-fuel stop valve (center) with trip oil after verifying that the spring is in good condition

17. Remove and service the main power circuit breaker (device 52G)

replace seals, inspect the jaw clutch as described previously.

- **Combined gas stop/speed ratio** and control valve. Replace servos with spare set and return to manufacturer for service, inspect gas-valve plugs and clean valve seats, stroke-test gas valves with hydraulics.
- **Hydraulic dump valve** (Fig 15). Test solenoid valve 20HD and all electrical trips, verify that the stop/ratio valve will close on loss of trip-oil pressure.
- **Liquid-fuel stop valve** (Fig 16). Remove cover behind spring and inspect the spring, actuate the valve with trip oil.
- **Generator.** Remove the main circuit breaker (device 52G) from the generator auxiliary compartment for testing and service (Fig 17), maintain potential and current transformers as suggested by OEM advisories. CCJ



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Frame 6 balanced long distance by phone, text, e-mail

When a Kuala Lumpur-based overhaul contractor encountered ongoing turbine vibrations at the Sabah Electricity Power Plant in Labuan, Malaysia, its call went 13 time zones away to Paul Tucker in Texas. Tucker's first call was to Ken Knecht in Alaska. They agreed to work from their respective home offices to fix the problem.

Site data at Labuan was showing continued high vibration on both the cold-end and hot-end bearings of the GE Frame 6B turbine. To complicate matters, a major overhaul of the unit had been completed in late 2014. All efforts to improve the post-rebuild vibration signature were unsuccessful.

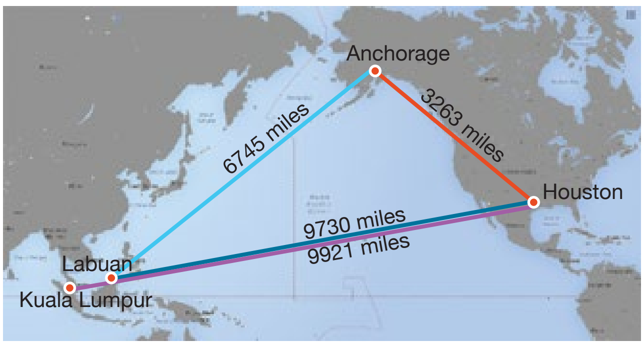
When the Malaysia call came in, Tucker, president, First Independent Rotor Services of Texas (FIRST), was just returning from Asia to his Humble (Tex) shop. Knecht, who recently joined FIRST, was away from his Eagle River base. Traveling quickly to Malaysia would have been difficult. They had a better idea: Solve the problem by long distance using modern communications technologies (Fig 1).

FIRST immediately asked for all site test data. Vibration spectra indicated a predominant frequency at the gas-turbine (GT) operating speed; the phase angle, a coupling imbalance in the turbine rotor. After reassembly data from the 2014 repair was received, Team FIRST spoke with key personnel at the rotor repair shop in Dubai and concluded balance weights installed during rotor balancing post overhaul were not arranged properly.

Digging further, Tucker and Knecht found an issue with the way the rotor had been repaired. They had some concerns about how the rotor was final-balanced, and specifically about the rotor's mid-span weight distribution. If that turned out to be the case, they could fix the issue at hand and pinpoint the original repair problem.

By now, the communication triangle was fully operational among Texas, Alaska, and Malaysia. All commonplace essentials were used: phone, text, and e-mail.

Discussing the data further with the outage contractor in Kuala Lumpur, all agreed to attempt a full-speed trim balance on the GT rotor in its current, assembled condition. All parties knew the alternative—to open the machine and go back in—would be costly in time and money. This particular engine was dispatched as a base-load unit in emergency-need situations. However, it generated income for its owner by being "available." It was not.



1. Long-distance balance by phone, text, and e-mail involved parties in Houston, Anchorage, and Kuala Lumpur and Labuan, Malaysia

1. Labuan, Labuan

The island of Labuan is also the capital of the Federal Territory of Labuan, a group of seven islands off the coast of Borneo in East Malaysia. The outage contractor was located on the mainland. Logistics can be difficult. Knecht, also a pilot and owner of Alaska Air Power, understands the logistics and compares it to Alaska where getting around can be both problematic and time consuming. This also added a new dimension to the communication triangle which would need to shift away from the mainland.

How it worked. Communicating with the contractor's vibration technician, Knecht developed a detailed procedure and prepared custom drawings plus a list of test weights that could be made or obtained in Malaysia. Specialized weights for the balance shot would be sent from Houston. When Tucker and Knecht concurred, all material was transmitted to the contractor. Back in Kuala Lumpur, the contractor reviewed the procedure and information, confirmed their agreement, and prepared to mobilize to site (Sidebar 1).

The setup. The Luban Frame 6 is equipped with accelerometers at all bearing locations, but non-contact proximity probes were never installed on this unit. Knecht noted that late-model 6Bs allow for adding external rotor weights in the field, but this an older unit, did not.

Portable balance pickups would be installed on the output shaft of the accessory gearbox, the cold-end (P1) bearing, the hot-end (P2) bearing, the input side of the load gear, and the opposite side of the input high-speed pinion gear (Fig 2). A photocell pickup was installed on the accessory-gear coupling, and a reference point on the accessory coupling would be used for the full balancing procedure.

The accessory-coupling-hub turbine-side bolt pattern was used for test and balance-weight location P1. The turbine-output-shaft hub bolt pattern was used for a balancing location relative to the reference on the accessory coupling.

Knecht explained that a test-weight value could be used by removing one of the 12 coupling bolts on the cold end (P1). Since the unit could not accept an external weight, removing a bolt from this end essentially added that weight on the other side, the quickest way to do a test weight. An external balance groove exists just forward on the rotor's output coupling hub. It was used for test and balance weight loca-

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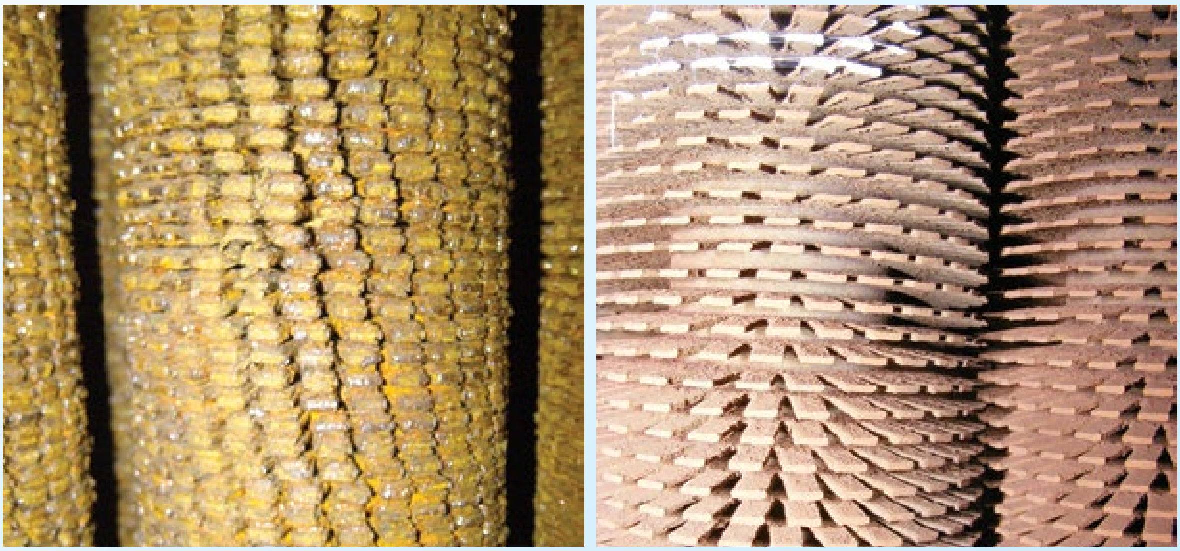

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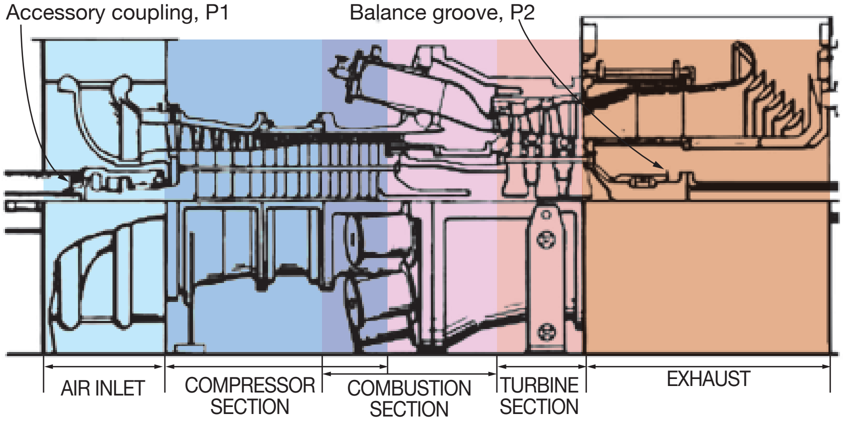


2. Portable balance pickups were installed on the output shaft of the accessory gearbox, the cold-end (P1) bearing, the hot-end (P2) bearing, the input side of the load gear, and the opposite side of the input high-speed pinion gear

tion P2 on the hot end.

Monitoring from afar. With all portable pickups and key phase probes installed, site testing began. For each test, all instruments and locations were first photographed and transmitted to Knecht for verification. The original run was completed then all data recorded and transmitted. FIRST next calculated a correction weight at P1, to be installed by onsite personnel. A second run was completed, recorded, and transmitted.

Then FIRST calculated a summed weight which was installed for a third run. From this run, Tucker and Knecht determined that an additional trim balance weight would be needed by additional correction to the hot end (P2). A test weight was installed, and another run was completed, recorded, and transmitted. With the test weight data from both P1 and P2 in hand, FIRST calculated the balance shot. The balance calculations were correct (Sidebar 2).

Run lengths were determined by the stability of the readings, and most reached stability between one and four hours. All participants put in extra hours as needed. As Knecht stated, "you just can't rush a balance job."

Some cultural details added to the time-zone differentials. Most site conversations took place around 1 or 2 a.m. in Alaska. And although all participants communicated in English, there were dialect variations and some participants spoke very quickly. Therefore, requests to slow down or repeat became the norm.

Most conversations then were confirmed by back-and-forth texts and e-mails (texting being the most useful). Transmitted photographs of equipment setups also were critical.

The common communication channels became Tucker with the contractor and Knecht with the contractor's site technician. Interestingly, these four never spoke together as a group. Knecht would also receive an occasional call from the owner/end user in Kuala Lumpur, which he deemed "reassurance" calls.

2. Results of pre- and post-balance by phone

Measurement location	Amplitude, in./sec Pre-balance	Post-balance
Cold end (P1)	0.54	0.04
Hot end (P2)	0.26	0.13
Load gear input	0.18	0.09
Load gear output	0.10	0.08

	Correction weights, grams
Cold end (P1)	260
Hot end (P2)	290

One significant adjustment was units of measurement. In North America, vibration levels are well known in inches per second. But the site was using millimeters per second, which can be difficult if you are not using that metric every day. As Tucker noted, someone tells you a journey will take 4 gallons, that's one thing. When they say it could take 15 liters, you might need to stop and think about it.

Moving forward. Long distance did turn out to be a better idea, and the project was completed within 10 days, including logistics delays. The more traditional response of air travel would have added travel time and expense, as well as delays coordinating logistics within Malaysia.

Instead, each group was able to concentrate on its participation in, and contribution to, the solution. Knecht believes the FIRST team would not have been as effective if it had taken the traditional response.

Tucker's summary: "You don't always need to be on site to help. And with this experience, we could do it again, perhaps even faster." CCJ

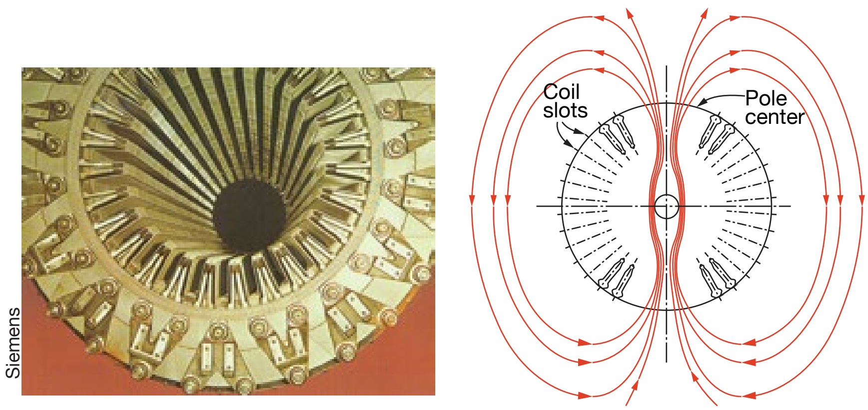
What's known, needs to be learned about stator magnetic core failures

By Clyde V Maughan, Maughan Generator Consultants

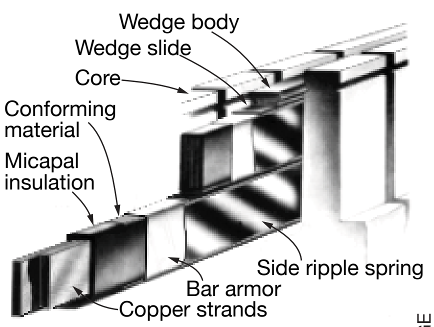
Stator cores historically have required minor, but common, maintenance to repair both impact damage from small foreign objects and cuts and bruises related to wedging operations. In addition, minor local or general looseness occasionally has been experienced and typically repaired successfully by tightening of the clamping flange and/or insertion of tapered wedges in the teeth.

But major failures have occurred for several identifiable reasons—including widespread damage from a large magnetic object in the air gap, fracture of a stator bar, over-fluxing, severe impact by the field during installation or removal, and gross clamping-force looseness. Catastrophic, spontaneous meltdowns have been rare and seem confined to a few models.

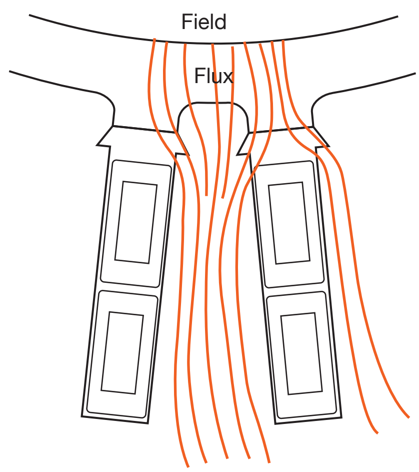
The objective here is to review the basic design features and components of cores, and to provide owner/operators a summary of core incidents worth remembering during generator inspections and review of operating data. Important to note is that of all generator components, the core may be the least well understood. It is deceptively simple in construction, but complicated in the extreme in its magnetic, mechanical, and electrical duties—and in the diverse ways it can fail.



1. Stator core without the winding or other peripherals is at left, air-gap flux path for a 2-pole generator at right



2. Core components and stator-bar support structure include core teeth, stator bars, wedges, packing, and side pressure springs



3. Magnetic shield protects stator-bar conductors against the powerful air-gap flux

Stator core design, construction

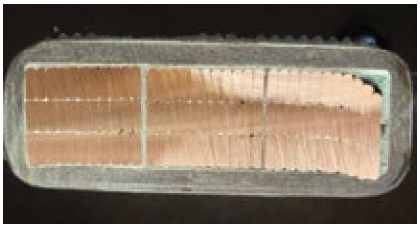
The core provides these three basic functions:

- Serves as the stationary path for the magnetic flux in conjunction with the rotating field.
- Contains and supports the stator bars.
- Shields the stator-bar conductors from the potent air-gap flux.

Core magnetic flux path. A stator core without the winding or other peripherals is shown in Fig 1 (left), the air-gap flux path for a 2-pole generator alongside.

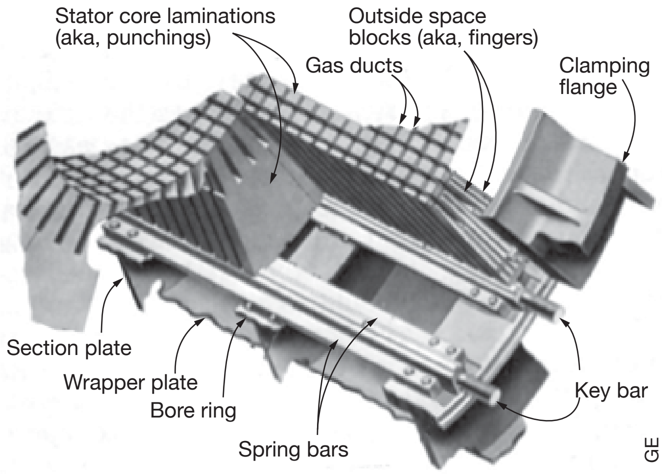
The main air-gap flux (as distinguished from the local fluxes driven by the current of the individual stator bars) is driven by the electromagnetic force (EMF) of the field winding current. The flux path is through the field body, across the air gap, through the stator-core teeth, and then circumferentially 180 electrical degrees around the back iron of the core. Recall that for a 2-pole generator, 180 electrical degrees equals 180 mechanical degrees; on a 4-pole generator, 180 electrical degrees equals 90 mechanical degrees.

Core support for stator bars. Components of a core and the stator-bar support structure are illustrated in Fig 2. Most large generators also will have a top ripple spring. Because the EMFs on the stator bars can be very large, above 100 pounds per lineal inch of slot, the ability to provide strong mechanical support of the bars within the core slots is vital.

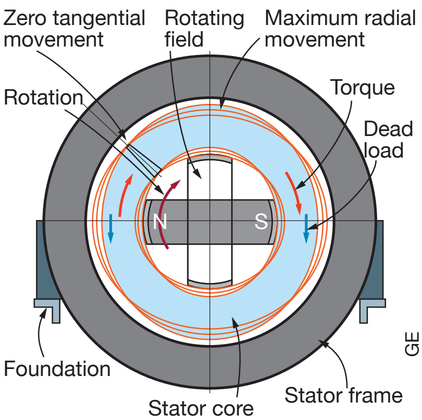


4. On hydro-generators bars are not set deep in the slot, thus the air-gap flux cuts the top strands in the top bar. Photo shows the upper-most strands of the top bar have moved sideways within the groundwall insulation and caused winding failure

5. In high-speed generators with indirect-cooled stators, the large set-back and step-back of core iron at the ends of the core protects against the condition shown in Fig 4



6. The magnetic core, and frame, are a complex structure. One of many alternative designs is shown here



7. The large magnetic pull of the rotor air-gap flux on the core causes the latter to deform into an oval

Core magnetic shield of the stator bars. Much less considered is the vital shielding of the stator-bar conductors from the powerful air-gap flux. The shielding effects are described in Fig 3.

On typical 2- and 4-pole high-speed generators, the top of the conductor (strands) in the top bar is at a depth where virtually all of the air-gap flux has transferred into the low-reluctance magnetic tooth as shown in the illustration. Thus there is little, if any, side thrust on any portion of the conductors. Without magnetic shielding, there would be a very-high side thrust on these conductors. It is doubtful that any electrical insulation system known could restrain these forces without failing.

The strand location situation is somewhat different for low-speed generators—such as those found in hydroelectric plants. On these units, the bars are not set deep in the slot, and thus the air-gap flux does cut the top strands in the top bar. There have been cases where the upper-most strands of the top bar have moved sideways within the ground-wall insulation and resulted in winding failure (Fig 4).

This condition leads to a concern relative to large modern high-speed generators with indirect-cooled stators, which typically have large set-back and step-back of the core iron at the ends of the core (Fig 5). The dusting visible in the photo on one side of the bar suggests bar-side vibration may be occurring because the air-gap flux intersects with the bar current in the upper strands of the top bar. The projection of the top of the top bar above the core iron also leads to a concern that the strand side movement illustrated in Fig 4 also may occur.

Worth mentioning, too, is that the stator-bar current creates these interesting and important phenomena:

- The amalgamation of stator-bar currents in a phase belt creates an EMF opposite to that of the field-current EMF. Net result: Air-gap flux is near constant under all load conditions.
- The currents in the two bars of an individual slot create a cross-slot flux that results in high EMF on the individual bars. This is a sinusoidal force, always downward for the slots with both bars in the same phase and a small upward force on the top bar on slots with the two bars in different phases. These somewhat complex forces are discussed in detail in Chapter 2, Design, of the author's text, "Maintenance of Turbine-Driven Generators" (QR 1).

QR 1

Core structure

The magnetic core, and frame, are a complex structure, as Fig 6 indicates. Many approaches have been taken to accomplish the functions observable in the illustration, but all have inherent complexities.

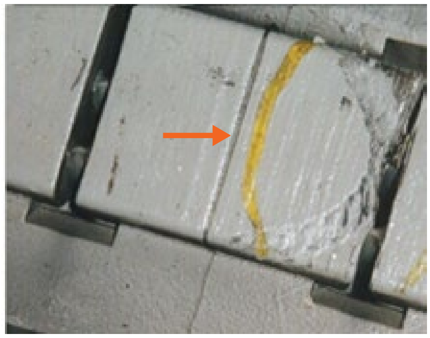
Core-to-frame isolation. On 2-pole generators the structure becomes additionally complicated by the necessity to provide for isolation of the frame from core magnetic deformation. The huge magnetic pull of the rotor air-gap flux on the core causes the core to deform into an oval; this deformation is small, about 2 mils on a well-designed unit (Fig 7).

But because of the masses involved, if not isolated, this rotating oval will cause frame vibrations, high noise levels, and exposure to frame and foundation cracking. Numerous methods are used to isolate the oval from the frame. Not all are successful. Example: Isolation is inadequate in the Fig 8 design, with noise levels as high as a painful 116 dB.

Core laminations. The core is built up of laminated magnetic steel. These laminations must be thin, other-

8. **Core key bars** are connected directly to the section plate via a bracket (yellow arrow) which, in turn, is connected rigidly to the frame (blue arrow)

9. **Core laminations** are thin (typically about 14 or 16 mils in thickness). Circumferential layers are segmented into several small pie-shaped pieces, which in a large generator may number more than 200,000



10. **Tooth looseness** in a well-made core is compensated by inserting a ring of tapered tooth-shaped shims every 20 in. or so of core axial length (above). Top edge of a tapered shim is identified in a core tooth by the arrow

wise the local eddy currents would be high and the associated thermal losses prohibitive—in the limit, a solid steel core would melt immediately upon application of field current. Typically, a lamination thickness of 0.014 or 0.016 in. is used; for handling/assembly purposes, the circumferential layers are segmented into several small pie-shaped pieces (Fig 9). On a large generator, there may be over 200,000 of these individual pieces.

Cores usually are hand-stacked, but recently robotic stacking has been successfully implemented by at least one major OEM.

Laminations must be insulated from each other; otherwise an immediate meltdown would occur. The lamination voltage is small, about 0.05 V; insulation thickness, 0.0001-0.0003 in. While 0.0003 in. may seem negligibly small, insulation thickness adds up to about 5 in. for a 20-ft core.

Further complicating core construction, lamination steel comes from the mill in large rolls. In producing rolls of thin steel, the mill passes the material through rollers which leave a very slight crown on the steel, slightly thicker in the middle. This causes looseness in the tooth and core OD. The latter has not been a problem, but tooth looseness has been. In a well-made core, tooth looseness is compensated for by inserting a ring of tapered tooth-shaped shims, every 20 in. or so of core axial length (Fig 10).

Core clamping pressure. Two general approaches are used in applying clamping pressure to the laminated core:

- Belleville-shaped clamping flange pulled tight with key bars only.
- Flat clamping flange with both key bars and through bolts for tightening.

The key-bar-only design is shown in Fig 6. This approach is considerably more common than the through-bolt design. Clamping pressure on the face of the core is made more-or-less constant by giving the face of the flange a Belleville-washer taper. While the uniformity of flange pressure on the core cannot be controlled accurately, the design seems to hold the core tight with little retightening of key-bar nuts required.

The through-bolt, key-bar design is shown in Fig 1. In theory, it should give a more uniform tightness on the face of the core than the key-bar-only option. However, in practice this design seems to require more frequent retightening of the two sets of clamping-flange nuts. In addition, it has the further complication of requiring that the through bolts be insulated from the core lamination—along the full length of the bolts as well as the nuts on each end.

Regardless of the pros and cons of the two designs, both can give satisfactory performance and both approaches continue to be used.

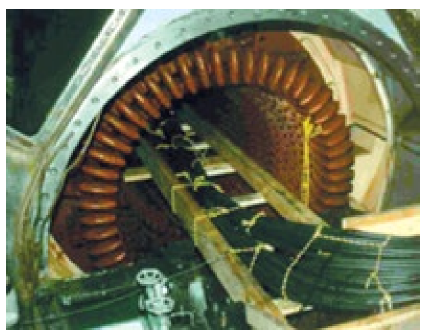
Inspection

Thorough inspection of the core on a large generator can be a tedious and frustrating experience. There is a great amount of surface to be inspected, it must be clearly seen, and a significant portion is awkwardly overhead.

Initial inspection of the surface can be done with the naked eye, as virtually all defects and problems can be identified visually. With the field removed, the core ID is fully exposed. There is much less access to the core OD, access generally available only through manhole covers, cooler openings, and high-voltage bushing manholes. But all accessible surfaces

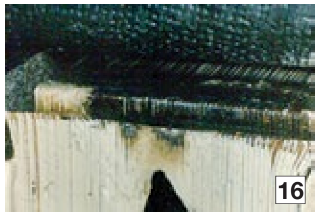
11. **Low-flux test** is performed using an excitation coil

12. **Chattock coil** assesses core condition



13. **High-flux test** typically is used today only when low-flux test results are questionable


CEMB


14-17. Expect to find minor problems when inspecting a core—including (from l to r) local looseness (14), nicks and cuts from rewedging (15), minor burning likely caused by FOD (15), and damage of concern (probably from foreign-object damage as well)

should be inspected. However, since most operational problems related to core OD surfaces tend to concentrate at the ends of the core, inspection of the core OD can focus on about the last 2 ft of each end of the core.

Any conditions of concern can be inspected in more detail with better lighting and by using a magnifying glass. On generators with radial ventilation ducts, some suspect locations may be seen using a borescope—for example, core iron at the bottom of the slot.

Bear in mind that core inspection is highly important and must be thorough. Expect that it will be time-consuming.

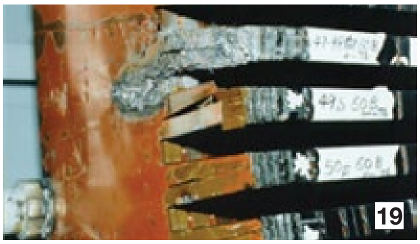
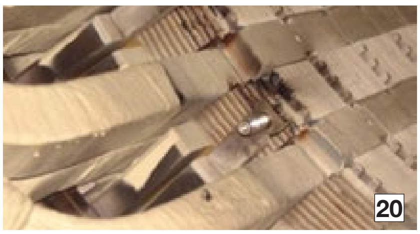
Testing

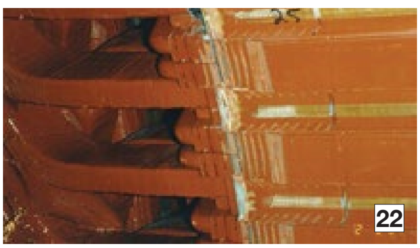
There are two common tests to determine core condition: low flux and high flux. Here are some details you should be aware of:

Low-flux test. El Cid (Electromagnetic Core Imperfection Detection) is the most widely used low-flux test. It came into common use in around 1980 and is simple, convenient, and completely safe to both the core and personnel (Figs 11, 12).

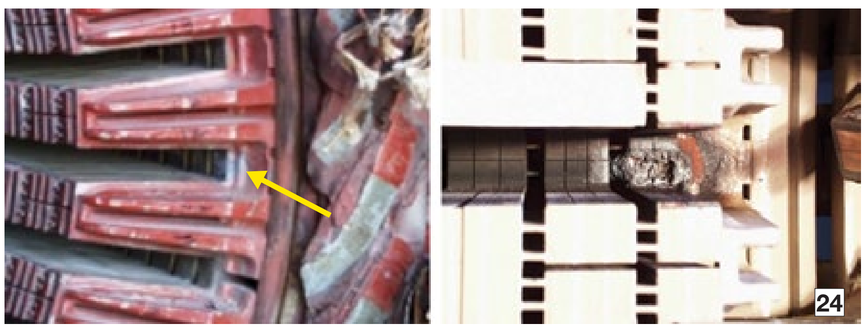
However, like all generator tests, it has weaknesses. Numerous incidents of questionable results have occurred. Examples: Core operated safely for three years after readings of 550 ma found; high readings resulting from insignificant difference in the iron used in different circumferential portions of core; low readings obtained on core that failed three hours after the generator was returned to service.

Nevertheless, low-flux testing is an important core evaluation tool and should be used (with caution and judgment) in conjunction with inspection for routine assessment of core condition. It should also be used before and after any work is done involving



18-22. Root causes of common core failures generally are well understood. Failure causes (top to bottom) include the following: Local core melting probably caused by FOD (18), melting of core iron attributed to an over-flux incident (19), failing core caused by local looseness (20), core-iron melting attributed to a broken stator bar (21), and severe core impact damage caused by careless handling of the field during removal

23-24. Some core failures are not well understood. One example is the total core meltdowns suffered by a particular line of large generators (top row, 23). A portion of the damage to one machine is shown in the photo at left; axial holes bored through the length of the same core are in evidence at the right. Typical of other unexplained core failures is below (24). An El Cid test did not indicate the slight discoloration (left) was of concern so a high-flux test was omitted and a new winding installed. Core failed at that location in less than three hours after excitation (right)

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possible damage to core iron—such as stator-slot rewedging and partial or complete stator rewind.

High-flux testing has been used since the infancy of the power-generation industry. However, it requires a HV power source, a suitable breaker, and long length of cable (Fig 13). The high current and voltage involved are hazards to both personnel and the core. Thus the test is not simple, convenient, or safe. With the advent of low-flux testing, the high-flux test is now largely used only when low-flux test results are called into question.

Deterioration, failures

When inspecting a core it is not unusual to find minor problems associated with the iron (Figs 14-17); they can be addressed conveniently in most cases. Not so with major failure modes, which deserve serious attention.

Major failure modes

Root causes of many common core failures are well understood and some failures are shown in Figs 18-22. A few major core failures are not well understood. To illustrate: On a particular line of large generators, there have been several total core meltdowns for which the root cause has only been speculated (Fig 23).

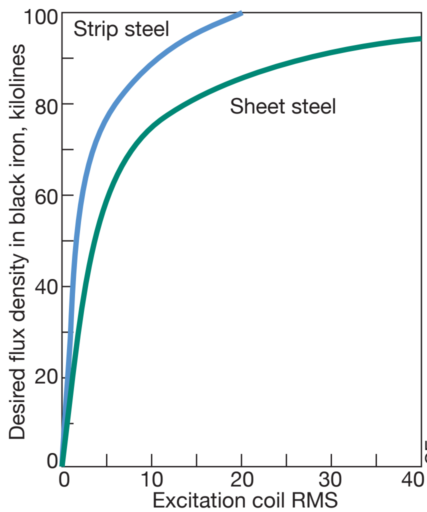
Typical of other unexplained core failures is the incident shown in Fig 24. During routine stator rewind, the core was inspected and the hot spot in evidence was detected. But since the El Cid test did not indicate a problem, a high flux test was not conducted. A new winding was installed and the core immediately failed at that location.

Siemens

25. Silver plating on flange and key bars is a somewhat complicated design phenomenon explained in the article

Unresolved core concern

Several years ago, generators began to exhibit silver plating of the key-bar nuts and the corresponding flange face (Fig 25). Given a background in generator design, one automatically assumes that the depth of core back iron has been reduced to a point where significant voltage is generated in the key bars.



GE

26. Calculation of excitation ampere-turns for high-flux testing is easy to do using curves in chart above. Not shown on the chart is the signature of author Clyde Maughan (Dec 4, 1952), then a GE employee, who developed the curves

This condition is a somewhat com-

27. Hot spots are created because of poor contact surface at the core ends where current is transferred from the key bars into the laminations (left and right)

28. Key-bar burning occurred in a core that failed because of an offline over-flux incident

29. Core melting is in evidence at the centerline of the slot bottom

plicated design phenomenon. But in effect, saturation is occurring in the back iron sufficient to drive significant (additional) leakage flux into the space beyond the core OD. That is, the design is moving up the saturation curve of Fig 26, from the red position to the blue position, thereby saving money by using less steel in the core.

The additional leakage flux cuts the key bars and generates a firm voltage which, in turn, promotes current flow through the key bars. This current flows in several complicated electrical paths, one similar to that of the amortisseur winding on the rotor of an induction motor—specifically:

1. Axially in the key bars to the end of the core,
2. where it then passes circumferentially 180 electrical degrees via the core clamping flange, frame structure, and core laminations,
3. transfers back into opposite-side key bars,
4. returns to the other end of the core,
5. then into the flange, frame, and laminations
6. 180 electrical degrees around
7. and back into the key bars to complete the circuit.

That portion of the current transferring at the core ends from the key bars into the laminations is passing through a poor contact surface, and tends to generate high heat. Hot spots can result (Fig 27). The burn location that may be seen during a very careful inspection is probably not a concern. The laminations already are shorted together by contact with the key bars, so unless the burn (which is driven by key-bar voltage, not air-gap flux) begins to run away, it should do no harm.

But the current that has transferred to the laminations must traverse the 180-deg (electrical) path passing from lamination to lamination through the insulation. It tends to concentrate toward the shortest path, thus increasing the current density near the bottom of the slots. These are locations that cannot be inspected (except maybe the below the bottom of slot location using a borescope). Furthermore, neither of the two types of core test will detect local hot spots at the OD of the core.

There are many hundreds of machines of this general design in service, and apparently none has failed because of such current flow. Thus it appears likely that the design is safe. Still, the burning observed on the core OD is almost identical in appearance to the core OD burning associated with the extremely damaging offline over-fluxing error (Fig 28). Thus a concern remains with respect to portions of the

30. Back-of-core iron burning occurred on a relatively new large generator

core inaccessible for visual inspection.

At the bottom centerline of the slot is both the concentration of current and junction between adjacent lamination pieces. This was the failure location of the over-fluxed core that forced the unit out of service (Fig 29), and this location would be the primary concern relative to degradation resulting from operation of stators for designs with significant key-bar voltages.

Because of concerns relative to current flow between key bars and core iron, designers have applied silver plating as shown in Fig 25. Also, shorting straps have been added between the key bars and flange. But, as noted earlier, the forcing voltage in the key bars is very firm. Thus these current-bypass efforts will tend to increase key-bar current flow and not be very effective in reducing the magnitude of the key-bar-to-core-iron currents resulting from the forcing voltage.

Therefore, a concern remains on generators showing core OD hot spots.

If key-bar currents in a line of generators were to become a core deterioration and failure mechanism, the first indication of trouble likely would be stator-winding ground failure caused by melting of bottom-of-slot core iron. Unfortunately, corrective approaches for a generator design conducive to serious key-bar current issues are costly: A new core at a minimum, a new generator a likely maximum.

Recent experience

As time has passed, it had gradually become the author's expectation that generators using the higher back-iron flux densities would continue to operate safely. Recently, however, a very large and relatively new 2-pole generator, one of nine installed in the US, failed because of core melting originating at the bottom of a slot. This unit is believed not to have experienced offline over-fluxing. The other eight generators of this design have exhibited the back-of-core burning (Fig 30).

The confidential details of the investigations into this recent and potentially very important core failure are not yet public. Hope is this information will soon be made available to the industry and some of the uncertainties discussed above clarified.

In conclusion, it seems certain that stator cores will continue to be an infrequent but major repair component on generators. The expectation is that in time (and broader dialogue among core experts with participation by owner/operators in industry forums such as the Generator Users Group and the International Generator Technical Community) core deterioration and failure mechanisms will become better understood. CCJ

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Improve plant profitability by optimizing thermal energy storage

Thermal energy storage (TES) systems increase profitability of gas-turbine-powered generating plants by exploiting daily pricing patterns to chill water in off-peak hours and then provide turbine inlet-air cooling in peak demand periods to boost output and improve heat rate.

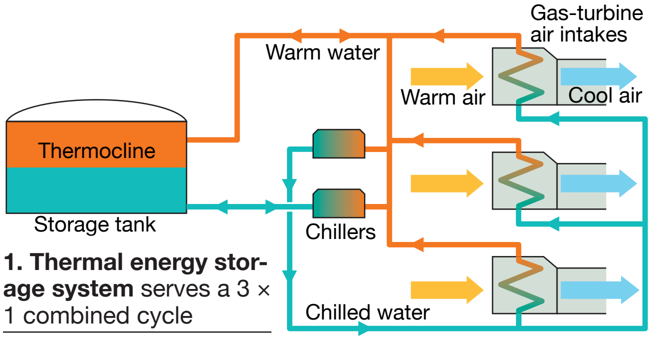
However, TES systems often are operated using default running schedules based on vendor design calculations, which do not account for the actual prices of electricity and natural gas, or weather conditions, or the thermodynamic state of the plant. The high variability in external and internal conditions during plant operation implies that a fixed operating policy is sub-optimal in real-world situations.

This means further significant benefits—perhaps \$1500 to \$3000 per day for 500-750-MW combined cycles—may be available by optimizing TES operation. Real Time Power Inc (RTP) shared with attendees at the recent Combined Cycle Users Group annual meeting (Orlando, Aug 24-27, 2015) the company's automated software solution for computing the optimal TES run schedule for both day-ahead and real-time markets.

RTP's David Davis explained the application and how data from both the powerplant and energy trading floor are used in state-of-the-art optimization techniques to maximize cash flow within a given time period.

A typical TES system produces chilled water which can be stored in a large well-insulated tank or sent directly to cooling coils in the gas-turbine air inlet house (Fig 1). Inlet air also can be cooled using chilled water from the tank, a preferred option for peak demand hours to reduce parasitic power consumption.

The chilled and unchilled water are stored in the same tank; there is little mixing between the two layers. The thermocline level is defined as the height in the tank where there is greatest temperature difference between the warm water above and the cool water below.



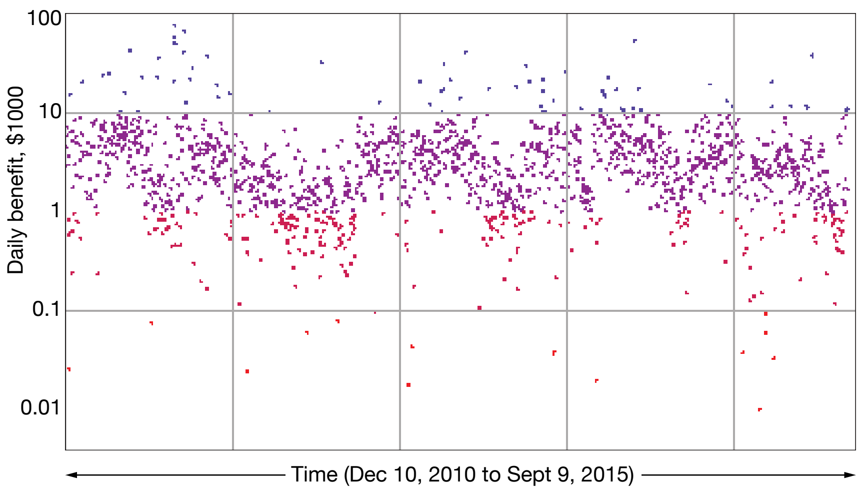
1. Thermal energy storage system serves a 3 × 1 combined cycle

TES optimization is performed by maximizing the cash flow derived from the chilled-water resource while respecting all of the physical and operational constraints. Silvia Magrelli, the R&D software engineer at RTP who led development of the application, said the optimal schedule requires the "solution of a constrained multivariable nonlinear objective function, and with the selection of the appropriate solver algorithm, the machine-generated answer will provide significant additional revenue gain over and above the default schedule."

The optimizer is layered on high-accuracy adaptive plant models which allow it to calculate key powerplant operational parameters for the forecasted weather conditions, and then also to predict precisely the incremental power and heat-rate benefit of inlet-air cooling, as well as the auxiliary load of the chiller units.

The final pieces of the jigsaw puzzle are forecasts of electricity and natural-gas prices, which enable decisions regarding GT run schedule. The outcome assures sufficient chilled water is available to meet the forecasted needs of the day-ahead market. Plus, in real-time trading it allows sudden changes in market and/or weather conditions to be assimilated immediately and the best use of the TES re-computed for the remainder of the trading day.

One important benefit of the optimizer, Team RTP stressed: It greatly improves the accuracy of day-ahead load forecasts because it always plans to return the TES tank to a specified



2. Most of the daily benefits from use of the optimal schedule (versus the default schedule) are in the band between \$1000 and \$10,000, but there are a few occasions where greater benefits were obtained because of market price spikes. However, price spikes usually are not predictable more than an hour or two in advance, and they rarely last for more than a few hours. The application's real-time market optimizer allows best decision to be taken when these spikes occur state at the end of each day. Thus, at the start of each trading day, the thermocline level is the expected value, and the forecasted load and heat rate can be achieved if the TES is operated according to the optimal schedule.

By contrast, with a default schedule, the end-of-day thermocline level is uncontrolled and will affect megawatt and heat-rate numbers for the following day. Finally, when plant equipment constraints are reached—such as maximum chilled-water flow rate through the cooling coil—the system will plan the day-ahead and real-time schedules based on best achievable performance.

Real Time Power has tested the application against five years of real price and weather data using actual plant thermodynamic models. Figs 2-4 present the results of this retrospective comparison for a 3 × 1 combined cycle in the South with a 5.75-million-gal storage tank.

The optimizer consistently outperforms the default schedule, and over the five-year period investigated, would have produced a $6.6-million benefit. The saving results from differences between the actual electricity price on the day and price curve used in designing the TES and in compiling the default schedule.

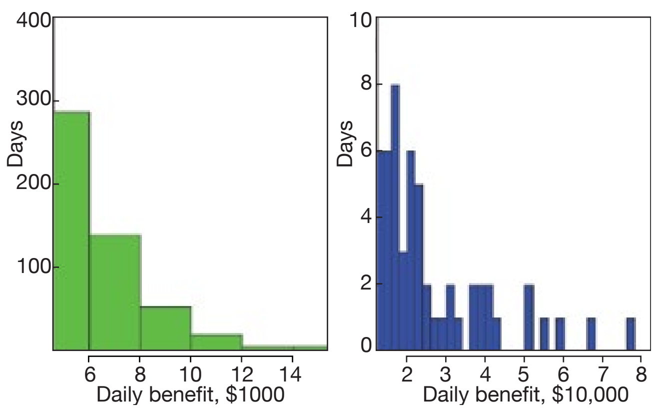
Installation of the RTP solution involves a server which connects to both the plant DCS and the energy trading desk. Control-room operators have the opportunity to set independent variable values and constraints—gas-turbine availability, for example. The system typically is accessed daily by the trader to produce the day-ahead declaration, and subsequently, as required during the current day, to make changes reflecting the real-time market.

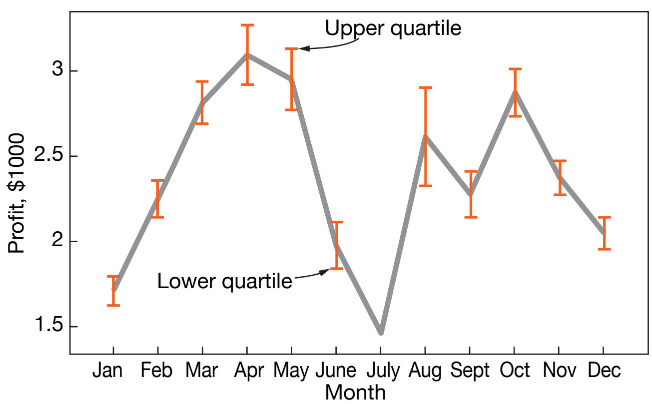
The optimal solution for a particular running configuration is computed in less than one second, making the system very responsive to changes in market and weather conditions.

Plant models used to compute the optimal solution include the following:
- Gas turbine power output.
- Fuel gas consumption.
- Chiller auxiliary load.
- Compressor inlet-air mass flow rate.
- Cooling-coil effectiveness.

Additional models for steam power augmentation, duct burners, and cogeneration steam supplies may be added if required.

Note that the models used are continuously adaptive, meaning that plant degradation is tracked, and, therefore, the optimizer always is making decisions based upon best available information. CCJ





3. Detailed breakdown of the actual market price spikes experienced in the five-year period profiled in Fig 2, and the associated optimizer benefits (left)

4. Seasonality of benefits for the five-year period investigated, reveals the largest average gains from use of the optimal schedule are in the "shoulder" months of April, May, and October. July has the lowest average gain, because the weather patterns are closest to design conditions. Nevertheless, an average gain of about $1500/day still is achieved (right)

Transparency prevails as gas-turbine owners, operators air experiences

"Guns don't kill people, people kill people." While one might argue incessantly about one of the favorite slogans of gun rights advocates, the sentiment behind it applies to what attendees heard at the Siemens T3000 Users Group Conference held, June 8-11, 2015, in Alpharetta, Ga. That is, T3000 control systems don't fail, per se, so much as lines of communication among those responsible for them can.

In this day and age of corporate paranoia over messaging, and little constructive critique and problem-solving for the good of the industry outside of closed rooms, the invitation extended to **CCJ** to participate in the conference is testament itself to Siemens' goal of greater transparency regarding T3000 implementations and continuing support. Owner/operators should view the issues identified here as punch-list items to review with other T3000 users and Siemens when evaluating existing automation or considering new or replacement systems.

In one session, a top manager for Siemens Energy Inc reviewed several "project implementation events" and lessons learned.

One involved uneven heating in the intermediate-pressure (IP) steam turbine after an IP control valve was inadvertently shut during warmup and high-pressure (HP) seal steam was improperly routed to the IP exhaust. From the control-system perspective, turning-gear logic was incorrectly applied to the warm-up procedure. The root cause proved to be that a logic error from an earlier unit, commissioned 10 years prior, was not caught when the second unit was commissioned.

***Lessons learned:** Don't change things in the field without informing engineers; conduct a critical design review and keep all conclusions in one place; and have a clear assignment of responsibilities.*

Another site experienced a phase failure between a B-phase circuit ring and a C-phase main bushing lead. This resulted in adverse temperatures in the generator resulting from erroneous stator and gas temperature readings, and insufficient cooling of the generator stator. From the control-system perspective, the root cause proved to be incorrect temperature readings traced to incorrect hardware proxy settings in the software. This had a serious consequence; the customer was out of operation for several weeks.

This was described as a human-factors incident. Siemens instituted a "quality stand down" at all commissioning sites and enhanced specific automation system testing, conducted internal and external quality audits, then rolled out a new performance training regimen for field engineers.

***Lessons learned:** Site personnel must validate commissioning procedures; don't fire people for making mistakes, but do fire them for not following procedures.*

A user responded from the audience that this should also be factored into lock-out/tag-out (LOTO) procedures, that a second human being must check everything as part of independent verification.

A third site experienced incorrect fuel fraction delivery to the gas turbine. The adjustment intended for one unit was entered into a running unit. The event was followed by a thorough job safety-analysis review.

***Lesson learned:** Require separate log-ins for separate units.*

Ethernet switches aggravating. There was little joy on either the user or vendor side regarding scalance devices, Siemens' version of an Ethernet switch, which does appear to be a straight-up hardware, rather than human, issue.

Faris Khalil, head of the Siemens new US R&D center, noted that failures of the "multi-mode fiberoptic Ethernet transceivers involve multiple communications problems, as well as defective soldering of the photodiodes." Siemens described the issue as a generic "open point." Apparently, the scalance devices are not Siemens products, and are plagued by batch manufacturing defects.

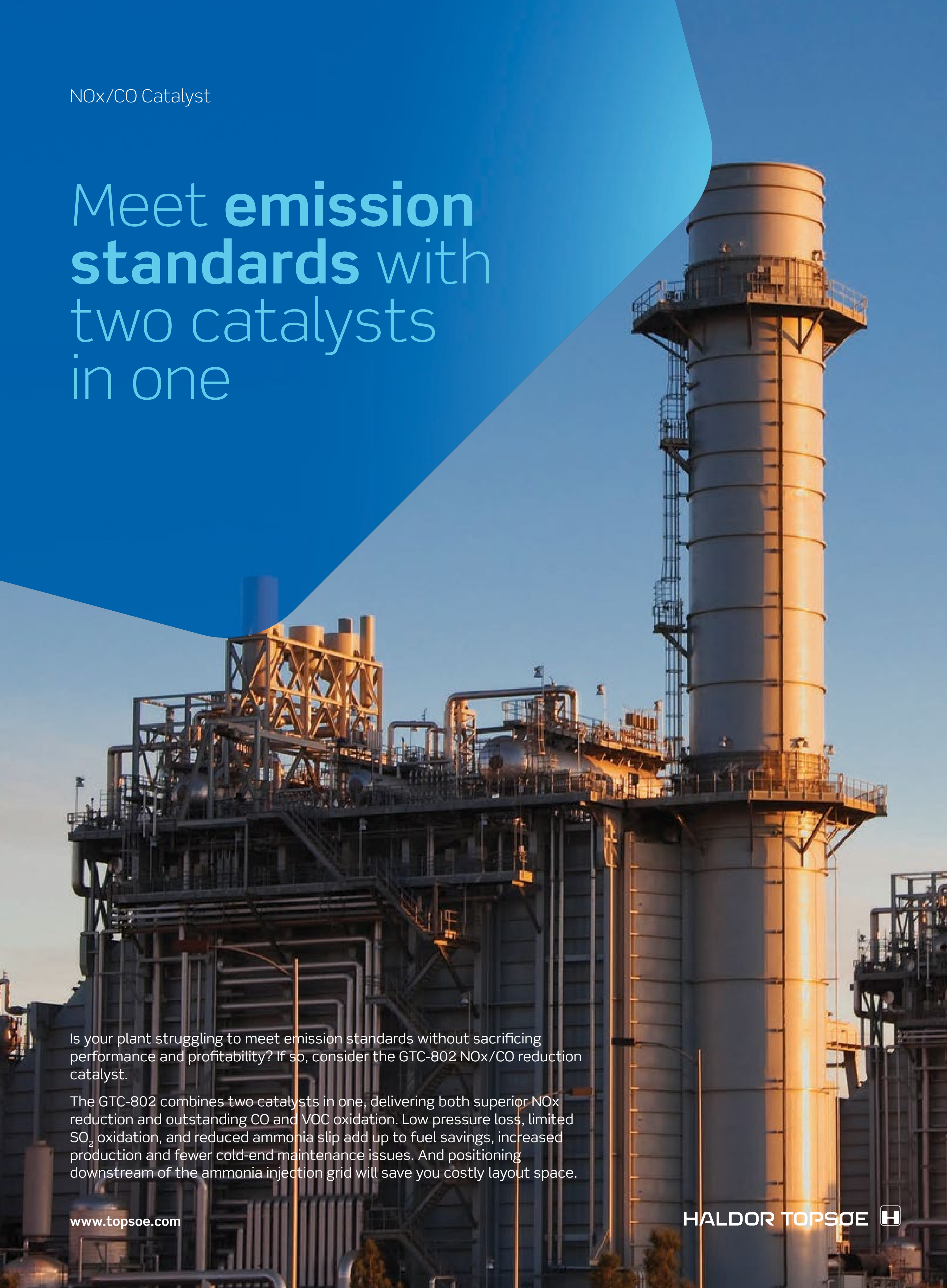
One user exclaimed, "We can't have failures of these things in the summer," suggesting the devices are important to uptime. He continued with, "We have more problems with the new system than the old TXP." Recall that T3000 has replaced Siemens' TXP control system at many US sites.

Another asked "how can a simple single switch cause a system failure?"—essentially confirming their importance. A third user asked if "there is anything plant personnel can do to check their own units?" The response was to make sure spares are on-hand.

However, even spares may not be adequate unless the serial numbers are traced to ensure the devices are not subject to the defect. Khalil responded that Siemens will not wait for scalance devices to fail but will be proactive in getting replacements to customers. A Siemens cybersecurity expert noted that all unused ports on the scalance devices need to be "locked down."

General grumblings, comments, observations. The following is a laundry list of other concerns expressed either from the podium or the audience:

- Many users complain about the slow T3000 "work bench," which integrates onto one screen all views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of the plant for operations, modifications, tuning, optimization, and I&C diagnostics (depending on access rights, of course). One noted that "the system works fine for a while, then destabilizes and has to be rebooted." Navigation buttons slow workbench down, another observed. (See sidebar for an overview of T3000 Release 7.2.)

- Servers from 2008 and before are no longer serviced, and upgrades are needed for Microsoft 2012-2016 based users. One user asked "why are you behind in your server development?" Concerns include reliability aspects and performance tests. The response was that it is difficult to change operating systems.
- The turnaround time between when a customer reports a problem and when Siemens is able to respond received spirited discussion. One commented that some problem reports were submitted a year and a half ago with no response. Another asked if there was a way to track progress and include more user involvement in the process. Siemens responded that it is adding two developers to the R&D group to improve the process.
- A user observed that few sites use the individual log-in/log-out features, preferring the plant as a whole to remain logged-in at all times. Users are skeptical and don't care for the "big brother" mentality or need additional oversight. In a similar vein, other users weren't crazy about search capability and accessibility of online logbooks, implying that the feature isn't valued, at least at the plant level.
- There was discussion about ability to turn application nodes on and off remotely. A user asked "what about emergency situations to access the automation data highway directly?"
- A user asked "how do we do a backup for the entire server?" Others responded that a procedure is necessary for conducting a full backup for disaster-recovery purposes.
- Issues with OPC (OLE for Process Control) communication represent the largest number of engagements between customers and the Siemens 24/7 remote expert network "hotline."
- Finally, one user observed (and several others nodded in affirmation) that Siemens was very good at getting replacement parts to customers but not good at communicating to users about the problem parts. CCJ

What's new about T3000 Release 7.2

The on-going transformation of powerplant control systems into a full-fledged knowledge, communications, and decision-support platform was clearly evident at the 2015 T3000 Users Group meeting. On display was Release 7.2, scheduled to wrap up pilot testing in early summer at a combined-cycle plant in Florida.

Faris Khalil, from Siemens' US R&D Center, summarized the objectives of Release 7.2 using these bullet points:

- Operator effectiveness.
- Integrated alarm management.
- Integrated applications.
- New look and feel.

Alarm management has been a bone of contention among users of all control systems for at least 10 years. DCS designers found it easy to add alarms and did so in spades, only to confuse and distract operators from the most important ones. First, operators tuned them out. Then they turned the nuisance ones off (predominantly the ones related to the I&C system itself). Finally, plant engineers went in and reconfigured them.

Release 7.2 incorporates new alarm classes: Trip Stop (TS), Trip Warning (TW), and Diagnostic Recommended (DR). Alarms are shown *in context.* Individual alarms are presented with the numbers of raised, unacknowledged, and pending alarms and one click leads to the relevant group of plant and operator displays.

The DR class of alarm messages is associated with model-based condition monitoring of the components most critical to availability. Unexpected deviations are indicated before alarm-limit values are reached. Then, again with one click, the operator can find advanced diagnostics for a more in-depth analysis and explanation—greater "intelligence," in other words, surrounding the problem. This, so-called, Plant Monitor is integrated in SPPA-T3000 and part of the new Release 7.2 applications bundle.

For minor incidents, the operator can address a problem and then enter the activity into the online shift log. A "shift book" feature is intended to replace or supplement the hardcopy shift log book. The shift handover can also be managed electronically. Open tasks can be loaded via one-click for the following shift. Once captured, of course, plant documentation can be made available to anyone with authority to view it through secure communications pathways.

Thus, the SPPA-T3000 integrates control, diagnostics, actions, and documentation into a single digital platform. The five basic displays are plant overview, alarm sequence display with open alarms, shift schedule with resources, pending "repairs," and open tasks. Whereas even five years ago, many plants would have separate maintenance management, alarm management, and model-based condition monitoring and analytics software packages (islands of automation), the SPPA-T3000, like other control systems, integrates this functionality into one platform.

However, it is important for users to understand, and as Khalil explained, that the TS, TW, and DR functionality has to be engineered into the system; it doesn't just magically appear. For example, the alarm-management package, including the replicated archive, can be purchased separately and plants need to ensure that they have the correct instrumentation onsite to inform the diagnostics. And Siemens has a separate product, called the CM500, which links to the SPPA-T3000.

The improved HMI (human machine interface) includes scroll-down access bars on the left and right sides of the screen for links to other applications (Siemens, as well as third-party, or any HTML-accessible app) most relevant to the operator's everyday responsibilities. Key performance indicators (KPI), such as output, emissions, heat rate, and others can be customized to suit each plant. A "Health" display, an overview status of components on one side, and detailed view on the other side, is available as well.

On the connectivity side, Release 7.2 includes enhanced HART functionality, advanced turbine control, and the next evolution of the Ovation migration strategy, and features further improved compatibility with Allen Bradley programmable logical controllers (PLC). Siemens is also deploying the built-in capability for plant performance monitoring and fleet performance monitoring.

Upgrading from previous versions of SPPA-T3000 also will include an upgrade of the Windows operating system.

Still only 50 bucks

The 7EA Users Group, which introduced an unheard of $50 early-registration fee for its annual meeting last year, remains financially sound and able to maintain a "depression-era" pricing structure for the 2015 conference, November 9-12, in Santa Fe, NM. As in 2014, the top price this year is $250 for those registering within about a month of the event—still the industry's lowest fee by a significant amount.

All who thought they were likely to attend should have registered early: The most you could lose was $50 by not attending; wait and you could lose up to $200 *for attending*.

With meals included in the fee, the total price of attendance (including hotel and airfare) is about $1000 for the majority of participants. How could any 7B-EA owner/operator justify *not* sending someone to this meeting? It's difficult to return without one idea that could save your plant at least $10,000 over the next year.

Pat Myers, plant manager, AEP's Ceredo Generating Station, has put in place a steering committee (sidebar) that supports both his no-frills philosophy and belief that presentations by owner/operators are critical to the organization's success. Result: Attendance continues to grow year over year.

A high achiever in both the gas and electric-power industries for four decades, Myers was recognized for his many successes by the Combined Cycle Users Group with its 2013 Individual Achievement Award. Recently, with retirement likely in 2016, Myers passed the 7EA leadership baton to Jason Hampton of EthosEnergy Group. Both will participate in the Santa Fe meeting.

The 2015 program is solid, featuring presentations by owner/operators on bus-duct failure, contractor safety, compartment roof sealing for CO_2 fire protection, DLN-1 fuel-nozzle failure, 9E design issues, rotor life assessment, secondary IBH valve, wrapper leak-mitigation options, and 3D training programs.

Vendor presentations focus on key user interest areas, including: circular non-segregated bus duct, clashing mitigation, liquid-fuel-system reliability, aft radial diffuser mods and repairs, evaporative cooling, generator life extension, exhaust retrofit, and others.

The OEM program, confined to the afternoon of the meeting's first full day, is noteworthy. It begins with an update on R1/S1 clashing mitigation solutions and then covers the following additional topics requested by the steering committee: forward compressor operability, No. 2 bearing, improving starting reliability, bleed-valve reliability, plant reliability, load-tunnel healing, case slippage, fast start, inlet-bleed-heat valves and control, and uprate opportunities.

If you haven't been to a 7EA User Group meeting lately, you're sure to appreciate the recent improvements. One example: The GE team, guided by Tom Freeman, Power & Water sales director for North America, is characterized by a more open approach to discussion of issues, and of progress in developing solutions, than had been the case previously.

Editorial observation: Freeman's positive influence over the last two years has been welcomed widely by participants in users groups supporting owner/operators of GE engines—including 7EA, 7F, Frame 6, and CTOTF™. Evidence, unscientific as it may be: A higher percentage of users is participating in the entire OEM session than only a couple of years ago and less skepticism is in evidence at coffee breaks.

Report card

This year's meeting begins, as it has for the last several years, with a State-of-the-Engine presentation by President Rod Shidler and Field Service Manager Mike Hoogsteden of Advanced Turbine Support LLC, which is based on fleet-wide findings from hundreds of borescope inspections over the last year.

At the 2014 meeting, Hoogsteden focused his remarks on Technical Information Letter 1884, "7EA R1/S1 Inspection Recommendations," April 2013, and TIL 1854, "Compressor Rotor Stages 2 and 3 Tip Loss," August 2012—both of great importance to 7EA owner/operators.

The service manager opened the 1884 portion of his presentation with a slide that screamed "Clashing woes continue," then migrated to the timeline (below) of important events from when the mechanism was first identified. Given the high percentage of first-timers at the conference, Hoogsteden's summary enabled those unfamiliar with the clashing phenomenon of great concern to 7EA users to come up to speed quickly.

Steering committee

Jason Hampton, *senior project engineer, EthosEnergy Group*
Pat Myers, *plant manager, Ceredo Generating Station, AEP*
Syed Mehdi Ali, *GM operations, Karachi Electric Supply Co*
Tracy Dreymala, *facility manager, San Jacinto Peakers, East Texas Electric Co-op*
Ronald Eldred, *plant manager, Rosemary Power Station, Dominion*
Michael Johnson, *powerplant supervisor, Turlock Irrigation District*
Guy LeBlanc, *supervisor, Consolidated CT Plants, First Energy Corp*
Tony Ostlund, *combustion turbine technician, Puget Sound Energy*
Lane Watson, *account engineer, FM Global*
Mirza Hossain, *plant engineer, TransAlta Corp*
Randall Rieder, *mechanical engineer, ATCO Power*

The timeline:

2006. Clashing—the word adopted to describe the contact that occurs when the tip of a stationary vane moves forward and contacts passing rotating blades near their platforms—was first identified in the first stages of multiple 7EA compressors. Years later it would be found in 7FA and 6B compressors as well.

2008. Advanced Turbine Support began using visible dye in its inspections. Back then, relatively few in the industry, including the OEM, appeared concerned about clashing.

2009-2010. There was a noticeable increase in the number of units affected by clashing. Also during this period, improvements in borescope technology allowed Advanced Turbine Support to add measurements to its documentation.

2011-2012. Inspectors noted increased damage, year-over-year, to airfoils in some engines that had experienced clashing. Documentation was upgraded to include trending data, and eddy-current inspections were implemented because of the elevated level of risk.

2013. The OEM's first technical information letter addressing clashing was issued in April. TIL 1884 identified a so-called area of interest on the suction side of Row 1 stator blades that should be inspected for cracking in units having experienced clashing.

May 2014. Inspectors from Advanced Turbine Support found two cracked S1 vanes in a single unit in the area of interest while performing a dye penetrant inspection. Those cracks were verified with eddy current. Yet another vane with multiple cracks in the area of interest was identified during eddy current testing of the entire Row 1. Those cracks, which had a maximum depth of 0.022 in., were retested with red dye and yielded no indications. A check of unit records revealed that from the time clashing first occurred in 2006 until cracking was found in 2014, the 7EA had operated only 3500 fired hours with 850 fired starts (round numbers).

1. Borescope examination of this 7E revealed material missing from the leading edges of some second-stage turbine buckets

October 2014. Technicians from Advanced Turbine Support identified cracking in the area of interest of an S1 vane in a second machine while performing a dye penetrant inspection.

During the OEM presentations at the 2014 meeting, attendees learned that one of the 7EAs inspected by GE technicians also revealed an S1 vane crack in the area of interest.

Hoogsteden continued with dramatic pictures of trailing-edge damage on first-stage rotor blades attributed to clashing. The severe damage had occurred in only two years from when clashing first occurred (a nominal 250 fired hours and 50 fired starts later), surprising many attendees. He closed out this portion of his presentation with recommendations for clashing inspections of 7EAs and the company's clashing history up until the time of the 2014 meeting.

Inspection guidelines. The speaker recommended owner/operators perform in-situ red dye penetrant inspections on all affected vanes and rotating blades each peak-run season, or every six months. He urged checking the trailing edges of all rotor-blade platforms, leading-edge tips, and the entire area of interest of S1 stator vanes that have contacted blade platforms. Suspect indications should be re-inspected with eddy current.

To sum up, by fall 2014, Advanced Turbine Support inspectors had identified R1/S1 clashing in more than 100 7EAs and R2/S2 clashing in over 25 engines. Also, they had found cracks in the area of interest in four vanes resident in two units and tears in the trailing edges of three R1 blades.

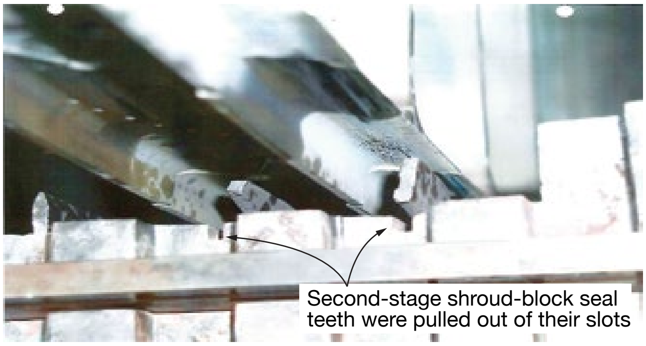
Other issues. After his remarks regarding TIL 1884, Hoogsteden briefly mentioned some other compressor issues Advanced Turbine Support inspectors were finding regularly, including these:

- S5 vane rock.
- Multiple stages with stator-vane rolled metal.
- Trailing-edge clashing damage on second-stage stator blades in 7E compressors; plus, leading-edge tip clashing damage on S2 airfoils. No TIL had been issued before the 2014 meeting to guide owner/operators dealing with this issue.

Shifting to TIL 1854, the speaker said the purpose of this advisory is to inform users about the recommended R2 and R3 blade blending and tipping to mitigate the impact of tip loss on availability and reliability. He mentioned three things that concerned him about TIL 1854:

- It does not address R1 blade tips.
- It does not recommend in-situ inspections.
- It considers "tip losses low risk to unit operation and reliability."

Tip distress on first-, second-, and third-stage rotor blades generally is caused by casing rubs during operation, Hoogsteden continued. Identifying characteristics include tip discoloration or a heat-affected zone, and rolled metal. Recommendations from Advanced Turbine Support, based on more than 600 in-situ 7EA R1-R3 inspections since 2009 that have identified more than 50 cracked rotor



2. Technicians from Advanced Turbine Support also found material missing from the knife-edge seals on second-stage shroud blocks that had released from their slots

3. First look at second-stage buckets as the turbine case was lifted

blades and found more than a dozen and a half tip liberations, include the following:

- For R1 and R2 blades with signs of tip distress, conduct visible dye-penetrant inspections to determine if radial cracks have initiated. These should be done up to four times at 25-start intervals, followed by two inspections at 50-start intervals, and then after every 100 starts—or annually.
- For R3 blades showing signs of tip distress, do a minimum 360-deg roll inspecting all blade tips close up and at the same intervals.

The take-away from this portion of the presentation: Rubs cause blade distress and may lead to metal liberation and collateral damage. In-situ inspections can point to corrective action required to mitigate damage.

What users shared

The 7EA Users Group's 2014 conference and vendor fair at the Embassy Suites in Murfreesboro, Tenn, attracted 136 owner/operators from 81 organizations. What follows are highlights of information shared by owner/operators during user-only presentations/discussions.

Shroud-block failure. The annual borescope inspection of a GE 7E gas turbine revealed material missing from the leading edges of the second-stage buckets (Fig 1), from the knife-edge seals on shroud blocks (Fig 2) and from bucket shrouds (Figs 3, 4). Third-stage buckets also were damaged (Fig 5). The speaker put Fig 6 up on the screen for first-timers who might be unfamiliar with the arrangement of turbine stationary components.

The inspection team from Advanced Turbine Support LLC recommended the machine not be restarted until engineering dispositions were complete; also that the owner/operator schedule semi-annual borescope exams going forward to monitor the condition

4. Close up of damage to the second-stage bucket shrouds

5. Third-stage buckets also were damaged

identified.

Engine history: The black-start, dual-fuel, water-injected unit began commercial operation in 1980. Primary use today for the simple-cycle engine is peaking service; it is remote-dispatched on starts and stops. Total fired hours at the time of the hot-gas-path (HGP) inspection was north of 41,000 hours. A major had been conducted in 2011.

Plant personnel investigating the problem asked 7EA users via the organization's online forum if they had heard of, or had experienced, seal liberation. One respondent said some pictures posted to the site revealed the affected seals had been inserted into slots in the shroud, as shown in Figs 7 and 8, and that these likely were replacements.

Traditionally, he continued, seals are an integral part of the machined shroud casting. The user suggested replacement insert seals can be successful provided the proper seal material is used and the inserts are staked securely and final-machined to the original circumference.

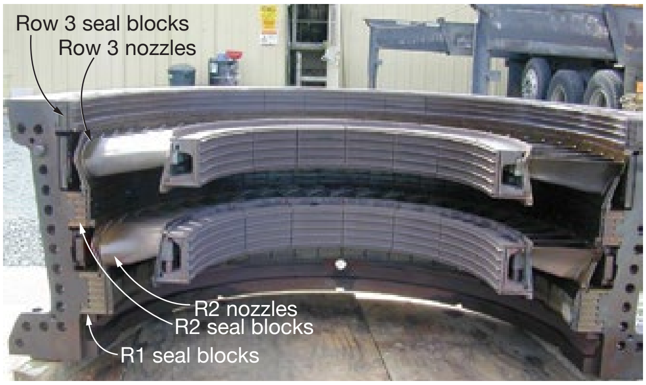
Next the speaker shared the history of the second-stage shroud blocks. The owner had purchased a repaired set with 18,000 service hours from a third-party vendor in 2011. According to the documentation provided, the pre-owned shroud blocks were weld-repaired as needed. Then the old seals were removed and grooves were machined into the blocks to receive the replacement seals. After installation, the new seals were machined to engine specifications and a coating was applied. Visual and dye-penetrant inspections were used to confirm the quality of work.

One of the consensus theories regarding the root cause of damage was insufficient clearance between the rotating seals on the second-stage buckets and the stationary seals on the shroud blocks. However, investigation by the OEM determined the clearances in question were acceptable.

Poor staking of seal strips was another root-cause theory, and investigators agreed with this. The original stationary seal strips were integral to the shroud block. When rubbing of those seals occurred, material was gradually worn away, but not liberated into the gas path.

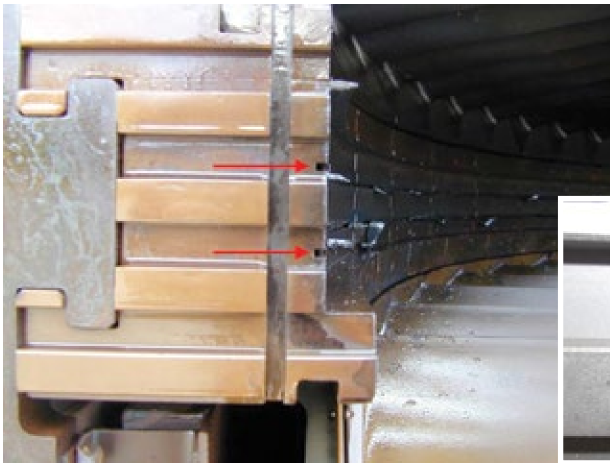
Repaired shroud blocks have seal strips peened into groves or welded to the blocks (Fig 9). Once rubbing of the poorly peened seal strips occurred, they were pulled from their respective blocks, rubbed the bucket shrouds, entered the gas stream, and damaged downstream components. Proper staking is shown in Fig 10.

A third possible root cause consid-



6. Position of turbine nozzles with respect to seal blocks is shown here

7. Damage to second-stage shroud-block seal teeth was extensive. Note that rotor rotation is from left to right, gas flow is from the bottom of the picture to the top

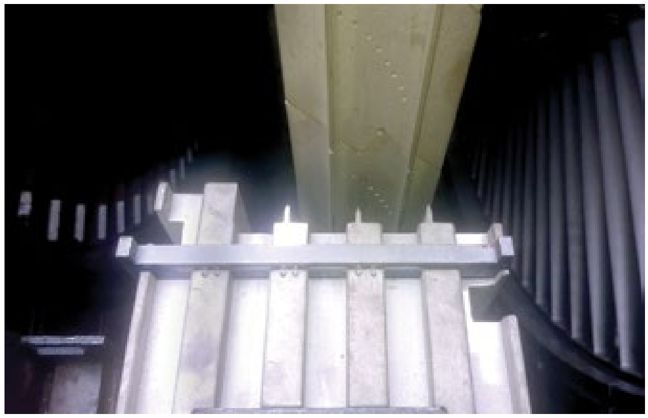


8. End view shows Row 2 seal-block slots absent teeth (left)

9. No weld or stake is in evidence to hold seals in place {below)

10. Proper staking holds seal in position

11. First-stage shroud blocks are in position and ready for operation



12. Second-stage buckets and shroud blocks were repaired successfully

ered was off-spec bucket and/or seal strip materials. But comprehensive metallurgical analyses eliminated those as possibilities. Investigators said, "Bucket and seal-strip materials were consistent with material selections typical for these components." Also, "Microstructures observed indicated exposure to anticipated operating temperatures but did not indicate excessive thermal ageing."

A transverse cross section through one of the second-stage buckets and longitudinal cross section through the bucket shroud were examined using a metallurgical microscope. The exam included evaluation for evidence of creep voids, bulk microstructure, external and internal surface conditions, and any anomalies. No problems were identified.

Shroud blocks for the first (existing), second (repaired), and third (new) turbine stages are shown in Figs 11-13 prior to machine reassembly for operation.

Clashing has been a common thread through 7EA meetings since 2008, based on CCJ notes, with the steering committee's Myers' hand on the needle. He has been relentless in the search for answers as to the cause, method of detection, and ways to prevent clashing.

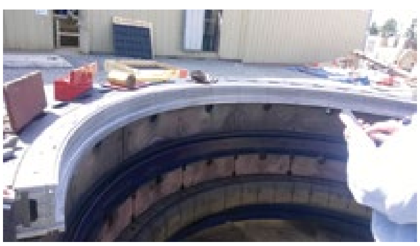
Myers characterized clashing as 7EA Ebola using the following bullet points:

- Many, perhaps all, units are exposed.
- Many units have had temperatures above the screening threshold.
- Two units in the fleet can be considered Patient Zeroes.
- None of the affected units have "perished"—yet.

The big difference between 7EA Ebola and the human disease, he said, is that "21 days after being exposed the risk does not go away!" To "kill" the machine virus, the OEM suggests installation of new S1 vanes and vane ring. However, Myers noted, users generally are not convinced that replacement of these components is a "permanent cure."

He then outlined possible steps to reduce "patient" risk until the "cure" can be identified and administered—and proven. These include:

- Inspection. What is the plan and proper frequency?
- Cropping of stator vanes. What are the specifications and impacts on compressor performance?
- Changes to operating parameters to reduce airfoil excitation.
- Vane profile modification to change the resonant frequency.



13. New third-stage shroud blocks were installed in the unit

With attendees' attention "locked-in" to the podium, Myers updated the group on his plant's experience. He said clashing damage at stator vane tips is increasing over time (both in terms of the number of airfoils affected and the amount of metal displaced), but Ceredo's 7EAs had not experienced cracking in the so-called *area of interest* on the suction side of R1 stator blades. The latter is particularly serious: It is conducive to the release of part of an airfoil and severe downstream collateral damage.

The most recent development Myers reported on was the work at Ceredo using acoustic monitoring and analysis to get a better understanding of when clashing is occurring. The collaborative effort with Mistras Group Inc began after the 2013 meeting and it is ongoing. One desired outcome of the work

would be an alarm that warns of vane cracking in the area of interest.

Mistras has deep experience in acoustic emission technology. You may recall that its Acoustic Combustion Turbine Monitoring System (ACTMS™) first detected and located an S1 vane crack in an F-class gas turbine over three years ago at a combined-cycle plant owned by NextEra Energy Resources.

Mistras algorithms continuously monitor for the different signatures associated with cracking and clashing activity while discriminating against normal turbine operating noise. At Ceredo, eight non-intrusive sensors are mounted on the casing outside wall at intervals of 45 deg along the S1 location. Waveguides transfer the energy from clashing or cracking to the sensor while dissipating heat. The sensor/waveguide assemblies are bonded to the casing surface.

Mistras has developed signal filters, validated by physical inspection, that identify when and for how long clashing impact events occur. Sinay told the editors the validation process revolved around Mistras relaying ACTMS data to Myers suggesting where he should look for clashing activity. Three of the four verification tests run were on target, and Mistras believes the fourth is a clash that cannot yet be seen. Next objectives: Determine if clashing occurs once per shaft revolution or more often, and at what power level clashing happens.

One of the most important findings of the acoustic analysis work done thus far is that clashing occurs most often during unit shutdown—something Myers has said for several years based on his observations. Engineers have determined that shutdown activity takes place within a few seconds and that it follows a periodic behavior. Knowledge of shaft speed at the moment of such response will help determine if there is a correlation and an optimal way of reducing rpm/load.

Clashing also has been identified during unit starts and during operation. However, no significant periodicity has been observed in cases where the activity occurred during stable full-load operation.

Another interesting “find” is that acoustic analysis can identify ice impacts, which likely would be of benefit for preventing compressor damage.

The OEM also presented on clashing at the 2014 7EA conference, but what its experts said is not covered here because more current results of ongoing work to resolve the issue were presented the following spring (2015) at the CTOTF™ meeting and are available in the report on that conference. Read the article immediately following this one.

Open discussion forums can be challenging, particularly when there’s a high percentage of first-timers in the room, which is typical at most 7EA meetings. The steering committee has to select discussion topics that they believe of interest to the group and if these don’t self-ignite, committee members have to light the fire and keep it burning with their input. Sometimes burning wet hay is easier.

So, you say, why not ask the attendees what they want to talk about. Sounds logical, but reality is that users with many meeting notches on their belts might ask colleagues one-on-one, those attending for the first time often are reluctant to raise their hands in a room full of strangers. It’s a given that owner/operators pride themselves on developing solutions for knotty problems. They solved this one by placing a large white board at the front of the cavernous meeting room and asking those with discussion topics and questions to write them on the board during breaks. They did!

Committee members Myers and Hampton led the discussion, with the latter feeding questions/topics on the white board to Myers, who had the mic. Hampton jotted down attendee notes for follow up and put other topics on the board as they arose during the discussion. It wasn’t long before the second side of the board was needed.

Discussion had to be stopped by the timekeeper for breaks and meals.

A wide range of discussion topics was brought to the floor during the three-day meeting—some general enough to be of interest to the majority of attendees, others very specific and seemingly beyond the experience/knowledge of most users. Here are a few of the discussion threads the editors noted:

- A user asked fellow attendees for their thoughts on brazing. He said the vendor selected to rejuvenate first-stage buckets wanted to braze-repair longitudinal cracks found in some of the airfoils and he didn't have enough experience with the process to make a decision with a sufficient level of comfort. As you might expect, many opinions on this topic—certainly enough leads were provided for follow up after the conference.
- Another attendee asked for guidance on how to set up his Bently system to trip the unit on high vibration. He believed that feature was not provided to give operators the opportunity to identify and evaluate the underlying problem before deciding to trip, or not.

  Not many in the room with the experience to answer, but those who did had a great exchange among themselves about everything from Bently idiosyncrasies to the types of cables to use, etc. Then the user asked what should be the vibration trip point. Lots of advice was provided on this, too, with numbers ranging up to 10.
- Leakage at the flanged joints of the combustion wrapper was another discussion point. The initiator said no solution seemed to be working for him. A colleague suggested applying Deacon 770-P generously with a trowel. Allow excess sealant to squeeze from the flange during rebolting.
- Difficulty operating in lean-lean was brought to the floor. It was a hot-weather phenomenon according to the topic sponsor. A fellow user mentioned his success using a particular vendor to refurbish fuel nozzles and eliminate leakage at those locations. Someone else said his lean-lean problem was solved with a software solution. Yet another participant mentioned the possibility of wrong-size cooling-air holes in the combustion liners as a possible cause.
- The subject of frequent motor-bearing failures was introduced. A user said motors in the high-heat areas of the compartment were failing every couple of years. Over-greasing was mentioned as a cause, bringing another attendee to his feet. He had problems with bearing failures on package fan drives and said over-greasing was the root cause. Consensus was that less is more when it comes to grease. Another point shared: Grease can freeze, at -15F based on one person's experience.
- Over-greasing was later cited as a reason for the failure of starting motors. An attendee suggested annual inspection and maintenance—specifically online motor tests and regreasing of bearings (clean out the old before adding new grease). Several users said they had spare motors for this critical service. Another reported that vibration was killing the bearings on his starting motor. You can't just leave them in the stopped position when on long runs, he said. The O&M team at his plant put a ratchet on the motor and crank by hand periodically. They didn't want to bump the motor with the unit online.
- Failure of flexible recirc fuel-oil lines was noted. These lines should be tested, it was said, but one must be careful to avoid distorting the lines. System pulsations were identified as a possible contributor to the failure but an RCA showed the conical fine screens in strainers were the cause at one plant. Proof was that the problem disappeared after the screens were removed.

- Gas-skid winterization issues were a hot topic for a few minutes. A user reported valves freezing up last winter; heat tracing enabled proper operation. The skid heater also was upgraded to be sure the plant wouldn't fail to start because of a cold condition. Another facility reported installing explosion-proof heaters on the floor to ensure gas up to a properly operating valve. Having vent fans "off" in cold weather but programmed to start on a gas-detector high alarm was recommended.
- Varnish was mentioned by a user who reported that his problem disappeared when a varnish removal unit was installed at his plant. However, servos are still sent for annual maintenance by the manufacturer because he thinks it's a good practice.
- A prepared presentation on fuel-oil best practices stimulated some follow-on discussion. A user said tank samples sent to the lab showed their oil was in top condition. At least that's what operations personnel believed until the plant installed a water removal and filtration unit in the tank recirculation system as a best practice. A filter medium designed to remove water quickly expanded and blocked off the recirc flow. It was then that staff learned there was a considerable amount of water at the tank bottom and 4 in. or so of decaying oil above that before the fuel was of combustible quality. Obviously, that was the oil sampled and sent to the lab.
- Cold-weather best practice for peaking units: Have mechanical techs exercise valves first thing on especially cold mornings to be sure the gas turbine is ready to operate.
- Best practice for compressor bleed valves: Change out O-rings at least quarterly.

Vendor presentations

The second and third days of the conference were dominated by vendor presentations arranged by the steering committee. The morning of the second day belonged to David Lucier, founder and general manager of PAL Turbine Services LLC, and Paul Tucker, president of First Independent Rotor Services of Texas. Lucier covered the servicing of variable inlet guide vanes and maintenance of gas turbine auxiliary systems (see article, p 24), Tucker turbine seal pins and turning-gear reduction.

Tucker spoke about some of the "little," relatively inexpensive things plant O&M personnel can do to reduce wear and tear on their engines. The TRI seal pin he is an alternative to GE's three-pin arrangement. It was invented in 2005 and is now installed on more than 300 blade sets. Total fired hours are north of 2.5 million, starts over 27,000. Experience has been excellent, according to the speaker. Frame 7 users normally order the TRI seal pin for B, C, E and EA engines when turbine wheel dovetails are worn and regular bucket seal pins can easily liberate and cause downstream damage.

The seal is an alternative to coating the wheel and/or bucket dovetails. Tucker said it allows users to run with larger bucket gaps and to extend the time between outages, and would not liberate.

Reduce turning-gear speed. The wear and tear on turbine-wheel dovetails and bucket/blade shrouds caused by long-term operation on turning gear is discussed regularly at gas-turbine user group meetings. Many solutions have been presented by OEMs, third-party services providers, and owner/operators over the years.

One, and perhaps the most simple, is to reduce turning-gear rpm. For the GE frames that were the focus of Tucker's remarks, he said the ratchet is the best, but most costly system, rotating the shaft 15 deg every 10 minutes. The older style turning gear consists of a motor/gear arrangement that turns the rotor on GE machines at 6 rpm.

Cycle-based GE turbines with 6-rpm turning-gear arrangements, Tucker noted, are subject to excessive wheel/disc dovetail wear—including seal-pin liberation, heavy bucket shroud wear, and even bucket liberation.

What to do? Tucker asked, and then answered:

- Do nothing, and risk bucket/seal-pin liberation and downstream damage.
- Retrofit the turning gear with a ratchet system. Install is four to five weeks and the cost surely to run more than half a million dollars.
- Retrofit the turning gear with a variable frequency drive capable of reducing shaft speed from 6 rpm to any speed down to 1/3 rpm. This can be done for less than about one-quarter of the cost to install a ratchet.

Regarding the last bullet point, the so-called RPM Reduction Modification (RRM) offered by FIRST, is equipped with a hand-control pendant to permit independent control of rotor position during alignment checks, borescope activities, bucket removal/installation, and the marriage/mating of rotor couplings during outages.

The modification process begins with an engineering assessment, which takes about a week; next, drawings and approvals, three or four weeks; system manufacture is 10 to 12 weeks; shipping and onsite set-up can take a week or two. Commissioning can be completed in one or two shifts.

Lori Jenks, president and founder of Combustion Parts Inc (CPI), got the afternoon of Day Two off to a fast start with her presentation, "Transition Pieces and Combustion Liners: What to Consider when Buying New Parts." The first presentation after lunch can be challenging, but Jenks was upbeat and held the attention of attendees on a subject of considerable importance to virtually all in the room. This material was covered previously in **CCJ** (1Q/2014) based on Jenks' same-subject presentation at CTOTF in fall 2013.

Jason Dunn of Parker Hannifin followed Jenks, bringing attendees up to date on the company's wireless remote health monitoring products. They offer a relatively inexpensive way to track performance and to identify problems before equipment fails. The company provides platforms for local (in-plant) and remote monitoring, the latter making use of 900-MHz bandwidth and web-based software.

Parker's SensoNODE™ low-power sensors, powered by extended-life batteries, can be attached to equipment quickly and without wires or tools (using clamps, for example) and transmit pressure, temperature, and humidity data to a mobile device. SensoNODE Mobile connects up to five sensors concurrently and enables the user to view both real-time and historical information, and trend data as well. Plus, alarm alerts can be programmed into the device.

Mitch Cohen of Turbine Technology Services Corp, who presented on "Liquid Fuel Reliability," has a long association with the 7EA Users Group having shared his considerable expertise on DLN-1 troubleshooting, combustion tuning, and fuel systems at previous meetings.

Only a few years ago, many owners of dual-fuel engines were considering reconfiguring their gas turbines for gas-only to simplify inspections and sell off oil inventory "because it was unlikely that liquid fuel would ever be burned again."

Today, with the looming possibility of winter gas-supply problems driving up fuel prices to unacceptable levels in some areas—such as New England—and the need to be oil-capable to receive capacity payments where available, some gas-turbine owners are considering the conversion of gas-only machines to dual fuel. A 180-deg turn of events.

Cohen's introductory remarks reminded attendees about the increased complexity of dual-fuel systems compared to gas-only. He then provided a primer on liquid fuel storage for those unfamiliar with the behavior of oils left to sit in storage tanks for long periods, covering both microbial contamination and long-term chemical instability and how to cope with them.

Next, he discussed the handling and firing of liquid fuels, addressing fuel-filter O&M, coking of fuel nozzles and other components exposed to engine heat and how to prevent it, flow dividers, operating procedures to maintain liquid fuel systems ready for reliable operation, etc. A quick review of the equipment required to burn oil—including fuel nozzles, new end covers, fuel forwarding skid, fuel filters, atomizing air compressor, fuel pumps, all manner of valves—had to convince anyone listening that converting to dual fuel was a big deal requiring the expertise of knowledgeable parties.

Cohen concluded with the following key points for owner/operators of oil-capable gas turbines and those considering liquid fuel:

- Monitor fuel quality periodically and address fuel-quality issues on a timely basis.
- Reduce coking by lowering the temperatures and/or fuel inventory in critical fuel-system components. Water-cooled valves and post-shutdown purging of fuel from the system can help in this regard.
- Consider upgrading to corrosion-resistant flow dividers.
- Inspect and test dual-fuel components and systems regularly.

Kevin Deutscher of JASC had the perfect sequel to Cohen's presentation. His focus was operational readiness for liquid-fuel operation, plus testing of the liquid-fuel system without burning fuel in the gas turbine. Deutscher covered some of the same territory as Cohen regarding water-cooled fuel control products, but in greater detail.

The speaker moved from water-cooled valves to the company's smart fluid monitor which shuts off coolant flow to JASC valves when it detects leaks, thereby protecting the turbine. It also regulates the temperature of the cooling-water circuit to guard against coking and waxing.

ZEE, for zero emissions equipment, was the third and final part of Deutscher's presentation. It exercises and monitors both the fuel-delivery and flow-metering systems without burning liquid fuel. The bottom line: no emissions, no coking caused by conventional test starts.

Deron Johnston of Vogt Power International Inc provided a brief respite from presentations aimed at the gas turbine with his "Startup and Shutdown Considerations and Optimization," which was of greatest interest to owner/operators with 7EAs integrated into combined-cycle and cogeneration systems. Johnston's key opening point: It is possible to decrease the start time and reduce the life consumption of your heat-recovery steam generator simultaneously. An immediate payback of faster starting is fuel saving and a reduction in total stack emissions. Concerning the former, the speaker cited a case study for a plant that trimmed two hours from its start time and saved $500K annually, based on 180 starts.

A primary objective for a fast-start plant, Johnston said, is to maintain as much HP drum pressure as possible. This requires closing vents and drains quickly after shutdown. Keep in mind, he continued, that leaking drains require cold feedwater to top off the drum and this has a negative impact on pressure retention. Also, close the stack damper and GT inlet guide vanes to the degree possible. If your HRSG is not equipped with a stack damper, consider installing one.

One way to determine if your HRSG is starting as fast as its design allows:

Hire a boiler manufacturer or engineering firm to conduct a finite element analysis. You may learn ramp rates can increase without spending any money. Also worth investigating is the design life basis for your HRSG. Compare as-designed annual starts to actual, and maximize warm and hot starts to maximize equipment life.

Michael Keehn of CSE Engineering Inc presented on control system integration solutions to extend the Speedtronic™ life cycle. The experienced controls engineer began with a list of reasons for upgrading existing controls—including technology obsolescence, lack of OEM support, lack of integration capabilities, etc. Regarding obsolescence, he drove home the point that just "because a technology is old, it does not necessarily mean its functionality is obsolete and it must be replaced." Keehn pointed to the many early Speedtronic systems still in service today to prove his point.

The speaker spent some of his podium time supporting upgrade solutions on the basis of cost, eliminating the need for a massive retraining program for O&M personnel, the ready availability of components for legacy systems, etc. Keehn then dug into the pros and cons of alternative control system communication configurations and discussed one recent project of interest to many in the room.

Joe Clappis of MD&A's Control Systems Div presented a self-help clinic on when, and how, to calibrate LVDTs (linear variable differential transformers). It was well-received given the number of questions the speaker was asked. Calibration examples were presented for gas control valves and compressor inlet guide vanes. Plus, Clappis provided a sample LVDT calibration record/data sheet and set the record straight on calibration facts and fictions. Here are his summary/conclusion bullet points:

- Valve/IGV calibration it isn't; it's only LVDT calibration.
- LVDTs are devices—like limit switches, or pressure transmitters, and should be treated as such.
- LVDTs are stable and reliable, and not prone to drift.
- Replacing a servo valve doesn't require LVDT calibration. Reason: Replacing the servo doesn't change the stroke of the device or the actuator.
- It's important to measure actual physical position when checking LVDT calibration or when actually calibrating LVDT feedback.
- It's important to know the effective stroke of the device for which the LVDTs are being calibrated or verified.
- It's important to know if the device for which the LVDTs are being verified or calibrated have closed-end, and/or open-end, over-travel—that is, effective stroke versus actual travel must be known.

Ian Summerside, one of PSM's product line managers, presented on a Frame 7B low-NO_x combustion system retrofit using the company's LEC-III® system. It was the first LEC-III retrofit for that engine model, reflecting the pressure being placed on owner/operators of legacy engines to reduce NO_x and CO emissions. Summerside began by reviewing the national clean-power plan, which left the impression that many others in the room might soon be taking similar steps to reduce engine emissions.

Project scope was to convert four 7Bs from dual-fuel diffusion-flame combustion systems to gas-only LEC-III combustors. New gas skids and fuel manifolds were installed; existing water injection and fuel-oil systems were removed. Unit 1 was commissioned in mid June; Units 2 and 3 were in commissioning at the time of the 7EA Users Group meeting—three weeks ahead of schedule. The last unit was scheduled for conversion in spring 2015. Project duration in each case was about six weeks.

PSM has retrofitted nearly six dozen engines with LEC-III combustors since the first project was completed just before the millennium. Engine models converted to date include 7B, 7E, 7EA, 9F, 501D5, 6B, 501B6, and 9E. CCJ

Control system as powerplant brain: The quest continues

Anyone using a state-of-the-art "phone," tablet, pad, or other personal digital assistant (PDA) knows that it has become less a "device" and more of a personal information, entertainment, and life management system.

Similarly, today's powerplant digital distributed control system (DCS) is looking more like a platform for real-time asset management than simply an "automation" system—a fully functioning plant brain, if you will. This broad trend was once again clearly evident at the Ovation Users Group annual conference, held in Pittsburgh, July 26-30, 2015. The meeting was sponsored by Emerson Process Management Power & Water Solutions.

1. An Ovation retrofit of the burner management system (BMS) can make use of much existing equipment. Although Emerson specialists develop the logic, NFPA requires the procedure for burner-element staging to be approved by the HRSG and duct-burner manufacturers. Examples of hardware required by the new BMS include field-cable terminal blocks, flame-scanner amplifiers, cabinet heaters/AC, cabinet pressure switch, alarm horn, and utility outlets (left). Examples of hardware that will be removed include internal terminal blocks, interposing relays, PLC, power supplies, data-link hardware, and thermostats (right)

The "big announcement" from President Robert Yeager in the opening session, and threaded throughout later presentations, exemplified this trend. He said Ovation™ now completely integrates a Machinery Health™ Monitor, eliminating the need for a separate vibration and health monitoring system. The "consolidated architecture" includes prediction and protection software and a common cybersecurity platform. The Ovation Machinery Health Monitor (MHM) fits into a spare I/O slot.

Another integration feature discussed across several presentations is bringing the HRSG duct-burner management system (BMS) into the Ovation platform, adding redundant controllers and power supplies and providing more unit flexibility for coordinated dispatch and faster response to grid and market dynamics.

In general, duct burners are playing more of a role in automatic generation control (AGC). Selectively placing burners in and out of service under cycling conditions helps the plant respond quickly to load demands.

The typical legacy BMS, usually supplied by the duct-burner OEM, is located at the HRSG (that is, local control), programmed on a programmable logic controller (PLC) platform, and has a serial or Ethernet link to the control room for remote HMI.

Today, a locally placed Ovation controller or remote Ovation I/O (with controller in the control room) can be interfaced with some of the existing equipment—such as field cable termination blocks, flame-scanner amplifiers, cabinet heaters/AC, alarm and utility outlets, and enclosure box (Fig 1). All Ovation features—logic, network, troubleshooting, diagnostics, etc—then can be brought to bear on the BMS.

Integrating the BMS and staging burner elements are not trivial exercises. For one, a revision to NFPA 85, the relevant code, was issued last January (2015). Compliance issues include ensuring no single point of failure for the master fuel trip (MFT), MFT relays, and the desire to incorporate burner-element staging. The code also includes two new options for the gas-turbine purge credit when firing liquid fuels.

Also, the startup sequence involves purging the gas turbine and HRSG, purging the duct burner, duct-burner light off, bypass-damper manipulation, and fresh-air firing. The MFT signals must be hardwired directly to the BMS; the operator must, by NFPA code, have a dedicated manual trip button. The bottom line is that while controls specialists can do the programming, the procedure must be approved by the HRSG and burner suppliers.

It stands to reason that any control capability integrated into the main platform not only eliminates hardware, but also potentially troublesome connections, digital language translation, time synchronization, networking hardware, need for spares, and wiring; reduces training and support services; and harmonizes configuration, trending, alarming, setpoints, voting logic, and I/O modules.

Speaking of training, simulation can also be embedded into an Ovation virtual controller. With this feature, operators can train using models integrated directly into the Ovation system. The models are configured using the same engineering tools used to build the control logic. In time, the "integrated" capability will have simulation and control run from a single integrated database, and the "synchronized" version will use real-time data from the plant and additionally provide a look-ahead feature with prognostic capability.

Southern Company's Mississippi Power affiliate already has demonstrated Ovation simulation capability at the "embedded" level for Plant Daniel Unit 3 and is working towards the integrated capability by next year and synchronized "real time" level thereafter, according to Keith Nelson, who presented at the conference.

Finally, Emerson's Steve Schilling offered a round-robin list of features (including the ones described above) coming with the Ovation 3.6 platform now being "teed up":

- Integrated generator excitation systems (Emerson also supplies excitation packages).
- Support for the newly released Windows 10 operating system from Microsoft.
- Ethernet-connected Ovation I/O.
- Faster networks, faster processors, and larger buffers.
- Repurposing of data historian for much faster point scanning with more accurate time stamps and transmitting of the "non-control" points—avoiding the need for a separate historian.
- Ovation playback—or the ability to record and replay an event on Ovation graphics for conducting post-mortem analysis.
- High performance control room with advanced alarm management and analysis based on the ISA 18.2 standard.

In the bragging rights department, the proliferation of Ovation as the dominant powerplant control platform continues. Schilling noted that Emerson controls are represented in half the power-generation capacity serving the US. Glen Wagner reported that the company has recently completed retrofits of Siemens T3000 (with 12,000 I/O points), as well as legacy Foxboro and Honeywell control systems (not combined cycles). Nearly 50 gas-turbine control retrofit projects were booked within the last 24 months in North America alone.

New solutions are in progress for Pratt & Whitney machines, Alstom GT24, and Siemens V84 and V94 engines; solutions have been completed for GE 7FA, 7EAa, and LM6000 machines and are in commercial service. While most readers may associate Ovation with applications inside large powerplants, the platform is versatile and used elsewhere as well.

One example is microgrid management. On Catalina Island, 22 miles off the coast of Southern California, automation technologies from Emerson help Southern California Edison efficiently manage electric generation (Fig 2) and distribution infrastructure.

Ovation provides SCE operators a concise view of all generating assets (including 23 microturbines and six diesel/generators) to meet electrical demand while reducing environmental impact. Plus, it helps SCE manage a battery storage system, the island's LPG plant, and water treatment/desalination facilities. Emerson's SCADA technology contributes by maintaining a stable grid voltage on Catalina while enabling rapid response to changes in demand caused by fluctuations during the tourist season (Fig 3). CCJ

2. Microturbines supplied by Capstone Turbine Corp provide the flexible generating capability required on Catalina Island

3. SCADA technology provided by Emerson Process Management helps maintain a stable grid voltage. Photo is of Catalina's 12-kV switchyard

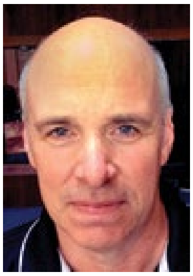
40 years and counting

CTOTF™ celebrated four decades of service to the industry with a gala celebration to kick off its fall 2015 conference and trade show in Coeur d'Alene, Idaho, September 20-24. The formal affair was a fitting send-off for Wickey and Mike Elmo, who retired after managing CTOTF meetings and the organization's administrative activities for the last 20 years, give or take. Their Puritan work ethic, business sense, warmth, and generosity were constants in a prolonged period of disruptive industry change, contributing very significantly to CTOTF's ongoing success.

Chairman Jack Borsch, recently appointed electric utility director for the City of Lake Worth (Fla), announced that Ivy Barton Suter and her brother, Greg Barton, of Event Planning Solutions LLC, would manage CTOTF meetings going forward. Both are engineering graduates of the United States Merchant Marine Academy (Kings Point); both sailed on their licenses.

Wickey Elmo calls it a career

Ivy Suter



Greg Barton

Suter and Barton already have the 2016 spring and fall meetings arranged. Renaissance World Golf Village Resort, St. Augustine, Fla, is the site of the April 3-7 conference; Westin Mission Hills Golf Resort & Spa, Rancho Mirage, Calif, hosts the September 11-15 meeting.

GE E- and EA-class

CTOTF's GE E- & EA-class day-long program at the user group's spring 2015 conference in Fort Myers, Fla, developed by Pierre Boehler and Ed Wong, PE, of NRG Energy Inc, Dan Giel of Duke Energy, and Dave Hollandsworth of Gainesville (Fla) Regional Utilities, exceeded expectations as usual with diversity in presentation topics and discussion.

The OEM's engineering team presented in the morning on rotor design and casing alignment, the Mark V control system, lube-oil systems, compressor clashing, and parts configuration management. In the afternoon, a

CTOTF™

Leadership Committee

Executive Board

Jack Borsch, *chair;* James Zachary Cowart, TVA, *vice chair, combustion turbine roundtables;* Ray H deBerge, Ameren Missouri, *vice chair, power systems roundtables;* and Richard W Evans, Old Dominion Electric Cooperative, *vice chair, growth and development.*

Roundtable Leadership Teams

Industry Issues: Greg Chancellor, SMEPA, *chair;* Ralph Jones, Essential Power LLC, *vice chair.*

O&M and Business Practices: William O'Brien, IHI Power Services, *chair;* Dariusz Rekowski, NV Energy, *vice chair.*

GE Roundtables: Pierre Boehler, NRG Energy, F-class chair; Marty Magby, Westar Energy, and Nathan Holland, TVA, *F-class co-vice chairs;* Ed Wong, NRG Energy, *E-class chair;* Dave Hollandsworth, GRU, *E-class vice chair.*

Mitsubishi Roundtable: Zach Cowart, TVA, *chair;* Mike Dwyer, Portland General Electric Co, and Christopher Kim, Dominion, *co-vice chairs.*

Alstom Roundtable; Bruce Barnhouse, Lincoln Electric System, *chair;* Greg Wilson, Kentucky Utilities, *vice chair.*

Combined Cycle Roundtable: Roger Schnabel, CAMS New Mexico LLC, *chair;* Rick Shackelford, Green Country Energy LLC, Mike D'Avico, JEA, and Doug Hudson, Puget Sound Energy, *co-vice chairs.*

Environmental Systems Roundtable: Kimberly Williams, NV Energy, *chair.*

Generator, HV Electrical, and I&C Roundtable: Moh Saleh, SRP, *senior chair;* Craig Courter, Guadalupe Power Partners, *vice chair, generators;* Ron Jernigan, NRG Energy, *vice chair, HV electrical;* and Doug Prindle, Ameren Missouri, *vice chair, I&C.*

Siemens Roundtables: Rich Wallen, Oglethorpe Power, *senior chair;* Olaf Barth, Dominion, *chair, V-class;* Dave Tummonds, LG&E, *chair, advanced frames;* Joe Mitchell, NRG Energy, and Scott Trantham, GRU, *co-vice chairs, advanced frames.*

Aero Roundtables: Jim Riddle, CAMS-Discovery, *senior chair;* Greg Dolezal, Klamath Cogeneration, *chair, FT8/FT4;* John-Erik Nelson, BELD, *chair Siemens ADGT;* Dennis Oehring, ProEnergy Services, *chair, GE LM class;* William Chen, LACSD, *chair, Solar.*

NERC/FERC Roundtable: John Horishny, Ethos Energy Group, *chair.*

user demonstrated how to remove the upper- and lower-half aft-compressor casing of a Frame 5, with the rotor in-place, to enable a hook-fit repair. Mike Hoogsteden, field service manager for Advanced Turbine Support LLC, followed with a presentation on advancements in 7EA first-stage stator vane inspections.

GE's 7EA product manager opened the meeting with a fleet overview—particularly worthwhile for first-timers, which comprised about one-quarter of the audience. Frame 7B-EA gas turbines, now installed in 99 countries, total about 224 GW in nameplate generating capability.

Experience includes more than 143-million operating hours and 1.2-million starts. The Frame 7 series of engines was introduced in 1971 with the 7A. The most popular machines in the nominal 1300-unit 7B-EA fleet are the 7B and 7EA, the last outnumbering all other units by more than two to one.

A few of the major design differences between the E- and F-class engines identified by the rotor expert:

- 7E is a three-bearing, hot-end-drive machine with alloy-steel turbine wheels. The 7E base design was created with a simple-cycle configuration in mind.
- 7F is a two-bearing, cold-end-drive machine with turbine wheels made of a sophisticated super alloy. The cold-end drive provides a straight path for the exhaust stream into the HRSG to maximize efficiency. However, this design increases the torque requirement through the compressor rotor and forward end of the turbine rotor.

The rotor presentation was a good backgrounder for all those concerned about rotor life (everyone). Here are some highlights:

- During the segment on rotor design basics, the group was reminded that the tight-tolerance, rabbet-fit feature of turbine wheels assures wheel centering for vibration stability and that the wheel/shaft bolt faces provide rotor backbone stiffness support and contribute to the transmission of torque.
- Creep, caused by stress and temperature, is the primary damage mechanism when engines are in base-load service. Fatigue affects starts-based units. Low-cycle fatigue (LCF) life is based on stress, which is influenced by speed and thermal condition. Forced cooling on shutdown adversely impacts fatigue life, but this effect is minimal on E-class engines. However, a combination of fast starts and forced cooling can get you in trouble over time.
- Ageing observations noted by the speaker:
  1. Embrittlement in E-class steel wheels. This is the change in a material's toughness/ductility over time. Different forms of embrittlement exist, but most are driven by the intergranular effects arising from time at temperature.
  2. Material softening—that is, the observed decrease in hardness readings on aft compressor wheels and turbine wheels. Ultimate and yield strengths move in the direction of hardness.

Clashing of rotating blades and stationary vanes in the first two stages of the 7EA compressor has been a topic of ongoing CCJ coverage for the last six years (refer to previous article). Gain access to all the articles published by the editors by using the search function at www.ccj-online.com. GE's presentation on clashing was of considerable interest to most users in the room. According to the speaker, the OEM is aware of more than 100 clashing events in the last five years; midspan cracking in the *area of concern* was identified at only one site.

Users have long been puzzled by the seemingly sudden appearance of clashing damage in one Midwestern 7EA peaker—and later all the units at that site—on a particularly cold winter evening about nine years ago. With the OEM mum publicly on the subject until recently, the 7EA Users Group and a few third-party equipment and services suppliers worked at identifying the cause of the phenomenon for years with limited success.

The speaker noted that operating profiles are changing today and engines are getting older so having new damage mechanisms crop up "later in life" should not be surprising. This is particularly true among E-class units, most of which have been relegated to low-hours peaking service, allowing them to sit for extended periods. In some environments these conditions are conducive to severe corrosion.

He said the key problem in 7EAs is vane lockup in ring segments, which reduces blade damping. This make the blade more susceptible to various phenomena, including rotating stall—the local disruption of compressor air flow during startup or shutdown which can cause a resonant response detrimental to materials.

Note that S1 problems associated with the 7EA typically have not been identified in the 7A-E fleet because the compressor designs are different. Specifically, the 7EA has a flared compressor and it has a different aero loading than the 7A-Es.

Other issues associated with 7EA S1 are the following:

- Tip liberations have been experienced in more than 30 7EAs—about 3% of the fleet—over the last seven years. Most tip liberations have occurred in coastal engines with airfoils made from GTD-450 material.
- Root liberations reported previously in 7FAs have occurred recently in two 7EAs with vanes made of 403cb steel, which was replaced in 1988 by GE with GTD-450

Of considerable help to owner/operators were these recommendations made by the subject-matter expert:

- With 403cb vanes, you can expect to see cracks before clashing occurs because of the loss of ductility over time. Inspect regularly to TIL 1884 for 7EA R2/R3 tip loss.
- Replace original vane carriers with ones made of stainless steel, to prevent lockup of vanes by corrosion products.
- Protect GTD-450 vanes from corrosion by coating with GECC1. Virtually all users attending the session thought GTD-450 could not be coated. The speaker's response: New solution for changing times; yesterday's solution is no longer applicable.
- Consult with the OEM about appropriate changes to the IGV schedule.

GE's engineering team is pursuing the root cause of the rotating stall in the 7EA, which compounds the likelihood of S1 issues. Plus, it is fine-tuning recommended operating procedures to minimize the possibility of stall. A beta test site already has been agreed to by a major utility with a large number of GT assets.

End notes: The joint task force established by CTOTF and GE reported on its progress investigating casing-alignment and failed liquid-fuel starts in the 7B-EA fleet. Regarding the first initiative, users were referred to TIL 1819R1 and GEK131700A for recommended inspections during outages to establish benchmarks for future evaluations and assess the need to perform casing alignments during major inspections.

The presentation on lube-oil systems, which focused on fleet performance and issues associated with certain fluids, generated significant discussion on PAG (polyalkylene glycol), a synthetic lubricant manufactured by Dow, and sold by American Chemical Technologies Inc, as a replacement for traditional mineral oils.

Unexpected findings, 7EA HGP

Managing expectations is an important process for O&M supervisory personnel: The less you expect, the less you will be disappointed—especially during unit overhauls. During the spring 2014 meeting of CTOTF's 7E/7EA Roundtable, a user profiled the first hot-gas-path (HGP) inspections for three DLN-1-equipped, dual-fuel peaking 7EAs installed in the early 2000s and covered under an OEM Contractual Services Agreement (CSA). Each of the units had experienced about 100 starts annually since COD and had about 1200 factored fired starts at the time of the outage.

1. Crack at clearanceometer hole, Row-3 12 o'clock position

The general condition of the units was "good. . .with outliers." The plan was to conduct a standard HPI according to the CSA in effect and do some blending in the compressor (made necessary by shim liberation). Questions that remained unanswered just prior to outage start: (1) Should shims be pinned? (2) Should a generator MAGIC (Miniature Air Gap Inspection Crawler) inspection be performed?

So much for the plan and expectations. Lessons learned included the following:

- Unsatisfactory thrust measurement approach caused erroneous scope growth.
- Turbine shell cracks were identified around borescope and clearanceometer holes.
- Turbine wheel corrosion found, in the OEM's view, warranted wheel replacement at the next opportunity.

Thrust measurements on the first unit inspected were made at the *load tunnel* and were within specifications; no further action required. On the second unit, thrust measurements made at the same location were double the specified amount. OEM and the owner figured the thrust pads must be worn and the outage scope and budget were changed to pull the thrust bearing.

The pads had slight wear; shims looked normal. But these parts were sent to a third-party services provider for a second opinion. Pads and shims were found to be within design tolerances. Thrust bearing was reassembled/reinstalled and measurements were checked at the *accessory coupling*. Thrust was within tolerance. According to the OEM's stated procedure, the measurement was supposed to have been made at the *accessory coupling,* but the crew opted for the *load tunnel* for easier access.

Attending user group meetings makes you aware of such errors of convenience, which can cause unnecessary expense and schedule creep. Listening to lessons learned by others reinforces the need for plant personnel to thoroughly understand the procedures documented by the OEM for specified outage tasks to prevent mistakes/oversights by contract personnel.

The casing cracks were a complete surprise. They were found during removal of turbine hardware from the upper half of the casing. Significant cracks were found at several borescope and clearanceometer holes, such as the one shown in Fig 1. No crack depth measurements were reported.

Corrosion was present in the third-stage wheel dovetails, preventing new twist locks from turning freely and engaging. Wheel required multiple iterations of CO_2 blasts and wire brushing to get the twist locks to work. As noted earlier, the OEM recommended wheel replacement at the next opportunity. Corrosion was blamed on peaking operations and condensation from metal temperature swings in a humid environment. The owner's engineers said the wheel wear-and-tear was similar to the corrosion experienced on its legacy 7Bs, but it was not expected on a 10-yr-old machine.

The generators for all three machines had not been inspected since manufacture in the 1999-2001 timeframe and the owner had planned to perform MAGIC inspections on all three units to establish a baseline. However, visual inspection of the first unit's generator indicated the machine was in such excellent condition, the owner decided to postpone MAGIC after conducting confirming diagnostic tests.

The shim-pinning question was answered by the need to meet an HGP budget challenged by the unexpected cost of thrust-bearing inspection. On the first unit, shim pinning was performed downstream of Row 4. Blade removal for Rows 1-4 was believed to pose greater destructive risk than shim pinning mitigated. Management punted on shim pinning in Rows 1-4 of the other two units for the same reason and decided against pinning shims in later stages of those units believing any liberated shims would not cause significant damage because of their size.

F-class hot-parts repair clinic

The CTOTF Leadership Committee invited Allied Power Group's (APG) Technical Director Aaron Frost to provide users attending the GE F-class and Siemens Advanced Frame Roundtables a backgrounder on hot-parts repairs. The expectation: Deeper knowledge would enable attendees to write more meaningful specs and make better decisions regarding contract awards.

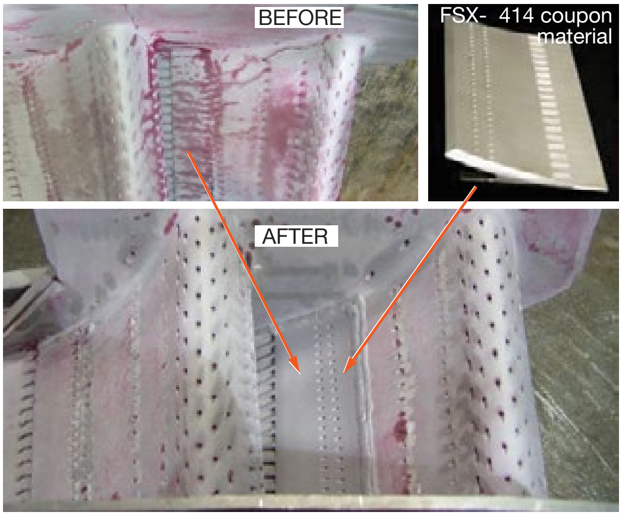
Frost has more than two decades of experience in the metallurgy and repair of hot parts—including a few years with the OEM and another third-party services provider before joining APG in 2009. Two characteristics of a Frost presentation: Slides are jam-packed with information (imagine a CliffsNotes version of a handbook) and a rapid-fire delivery.

His presentation on 7FA+e first-stage nozzle repair was first on the agenda at the GE F-class session. Frost is big on history, to help users better understand why things are the way they are. His backgrounder on stage 1 nozzles showed how component design progressed from the 7221 (7FA.01) through the 7FA.05. For example, nozzles for the first three engine models in this series were made of FSX-414 material (cobalt), the last two of GTD-111 (nickel); first and third models had some areas of the airfoils coated, the second none.

The Dot 04 and Dot 05 have some characteristics of the 7FB (only about a dozen built)—specifically, single nozzles (nozzles on the earlier engines are arranged with two airfoils per segment), and full thermal-barrier coating (TBC). Two other distinguishing characteristics of the 7FA.04 and 7FA.05 are that they have trapezoidal cooling holes; plus the GTD-111 material essentially is unweldable.

Thinking out loud, Frost guessed that the singlet design of first-stage nozzles for the Dot 04 and Dot 05, and the full coating of those airfoils, might be the OEM's solution to the first-stage cracking experienced on the earlier models in the 7FA series. He pointed to several photos of extensive nozzle cracking included in one slide, calling it "intimidating."

Cracking is most severe in the uncoated areas, the metallurgist



2. Weld repairs typically required on first-stage vanes are extensive, requiring bars and strongbacks to control distortion to the degree possible. Component shrinkage should be expected

continued, with significant thermal fatigue damage often identified as early as the first repair cycle in airfoils for peakers. But such distress is not exclusive to simple-cycle machines, he added; it has been found on base-load engines as well.

The required weld repairs typically are extensive, requiring bars and strongbacks to control distortion to the degree possible (Fig 2). Component shrinkage should be expected.

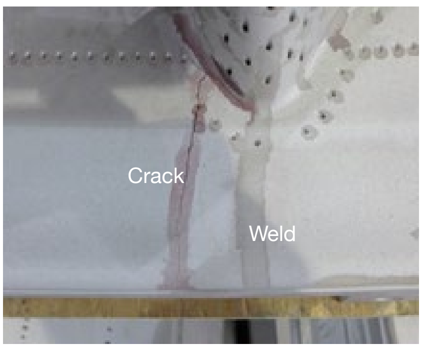
Caveat emptor. One got the impression from listening to Frost that the changing economics of buying new parts versus repairs to existing ones is challenging the current industry structure and may limit choices for owner/operators in the future. Perhaps not, but the new economics certainly means users will have to bone up on their knowledge of repair processes, industry standards, repair-shop capabilities, inspection technologies, etc, to protect generation assets.

Today, he said, new nozzles may only be twice the cost of repair. This means due diligence on repair shops is critical. With repair pricing exceedingly competitive, you have to be sure you're getting what you think you're getting, Frost said. Make sure you're comparing apples to apples when evaluating competitive bids.

Here are some numbers to ponder and help you understand what's going on. Assume the estimated cost of new first-stage nozzles from the OEM in 2003 was X. Four years later that price had dropped by about 25%; by 2010 it was about 0.5X; now it's approaching 0.4X. There have been significant cost reductions on the repair side as well. Consider the following timeline:

- In 2003 it cost Y for weld only and coupon repair.
- Four years later, the cost of repair had dropped by about 25%, similar to the reduction in the price of new parts; however, the scope had changed to weld/coupon/braze as required.
- This year you're likely to see bids in the neighborhood of 0.55Y, but for a reduced scope of brazing and minor weld repair.

Frost illustrated the impact of cost pressures by way of example. First repairs in 2008 by the OEM on nozzles with severe distress were characterized by minimal scope: Cracks were fixed using Renewalloy™, inspection was visual (no red dye or fluorescent penetrant), nozzles were stripped and recoated. Photos of the same parts received by APG five years later confirmed most



3. Expert weld repairs using the proper filler material can last a long time. Cracks develop elsewhere to relieve stresses in the component

cracks had been brazed, outer sidewall cracks were not repaired, surface craze cracking was extreme, overall nozzle fatigue health was poor. Frost's assessment was that the as-received condition likely would have been no worse had repairs not been attempted in 2008.

The APG technical director presented several other case histories as well. One revealed that one third-party shop wanted an owner to scrap a set of first-stage nozzles after two full repairs (one by the OEM) and about 40,000 hours/1600 starts and 50 trips, based on incoming inspection results and condition review after an acid strip.

APG accepted the challenge, installing trailing-edge coupons and welding all cracks with modified Mar-M-918 (a/k/a Nozzaloy). Butt gaps were repaired using Haynes 214 weld wire. The airfoils—which came to be known as the "train wreck" nozzles—ran more than 16,000 additional hours and 750 starts before replacement in 2012. A fourth repair cycle was not economically attractive for this set of nozzles.

Frost illustrated the importance of quality repairs and detailed photographic records in another example. As Fig 3 shows, Nozzaloy™ repairs, properly done, give excellent results. Cracks should not reappear during the next run; however, the inherent stress in the nozzles is relieved by a crack in another spot on the airfoil.

Frost's thoughts on braze alloys followed. He said the chemistry of braze alloys is provable and provided some examples. The metallurgist added that aero braze alloys sometimes must be customized for land-based service: "Just because it can fly, doesn't mean it's good for powerplants."

Several more topics were covered in the presentation, including a useful primer to help you better understand the value of fatigue data and what it means, how to calculate coating density using basic arithmetic, importance of bond coats, etc. All this material is available to users in the CTOTF Presentation Library at www.ctotf.com.

Some of the takeaways:

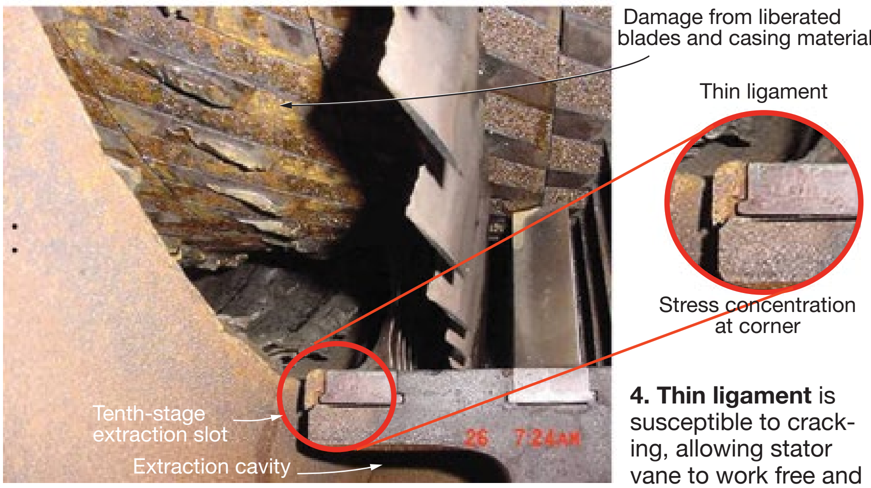
- High-density coatings (less than 10% porosity) achieve maximum cyclic life. A tightly controlled coating process is required to achieve this level of quality. Keep in mind that the thicker the coating, the more likely it is to spall; high-density thin coatings are optimal.
- Visual inspection has its shortcomings as a reliable indicator of repair quality.
- Non-OEM casting quality is higher than the OEM's in some cases.
- Users should carefully evaluate repair alternatives and repair services providers; the OEM often is not the optimal choice.
- Unrealistic specifications drive the wrong shop behavior.
- Performance loss and tuning issues many times are blamed on repaired parts. More often than not, this has no basis in fact.
- Braze is used for filling cracks where cost is the primary consideration.
- Acid stripping of cobalt-base alloys without pre-strip heat treatment is ineffective.
- Learn how to interpret parts numbers. All castings are not created equal; some suppliers are better than others and mixing blades of different origins can give you headaches.

Likewise, parts number revisions by the OEM can put you at risk in the repair process; know your parts and keep meticulous records.

501F row 1 turbine blades. Frost's second presentation at CTOTF's spring meeting, before the Siemens Advanced Frame Roundtable, reviewed the design history, repair, and field experience with 501F row 1 turbine blades. He began the history lesson with the 20-yr-old 501FC engine (170 MW, 15:1 pressure ratio, 2375F firing temperature, 1050F exhaust) and carried through to the 232-MW 501F4 machine with a pressure ratio of 18.9:1, firing temperature of 2475F, and 1100F exhaust.

Frost focused primarily on the design of Gen 1 and Gen 2 platform cooling circuits, tip plates, a successful seal-pin slot modification, and welding materials for this group of gas turbines, covering the various alternatives offered by the OEM, an alternative OEM, and major third-party parts manufacturer. With all the parts and repair options available to 501F owner/operators it might be in your best interest to review Frost's slides posted on a shelf in CTOTF's Presentations Library.

Considerable wear and tear in the platform area generally is addressed by the repair shop. For an OEM set of blades, all burned and weakened



4. Thin ligament is susceptible to cracking, allowing stator vane to work free and go downstream where it did major damage (Fig 5)

5. Compressor is corncobbed downstream of Row 9

base material at the platform edge must be removed before weld repairs. Photos in Frost's slides illustrated the problem. After the platform is fully welded, the front face is remachined to assure proper seal-pin fit-up, APG's platform cooling mod is installed and another mod implemented to prevent buildup of problematic foreign material behind the seal pin.

Suggested tip-cap welding and reconstruction procedures follow. Allied uses Haynes 230 material for its tip cap. First step in the process is to remove old tip caps and cooling holes, then pre-cap weld, tack weld the new tip cap, complete the tip-cap weld, and add the squeeler tip. Finally, the cooling holes are replaced, finishing the repair. Each piece then is checked by x-ray. Final step in the rehab process is the application of dense, vertically cracked TBC.

A step back to the Frame 5

Coverage of the Frame 5 rightly belongs in CTOTF's GE Legacy Roundtable chaired by NRG Energy Inc's Ed Wong, PE. But that forum is held only at the user group's fall meetings and the hook-fit repair experience TVA's Nathan Holland, vice chair of the GE F-class Roundtable, had to share was timely. Plus, most attendees at the GE E- & EA-class Roundtable, where Holland presented, likely have one or more Frame 5s in their portfolios.

As most Frame 5 owner/operators are aware, the thin ligament at the 10th-stage extraction slot in the compressor is a weak spot in the machine. It forms the hook that holds one side of the ninth-stage compressor stator vanes in place. Fig 4 shows the area of interest as well as the damage caused when the casing cracks, allowing one or more vanes to work free and go downstream. Fig 5 shows the damage south of the ninth stage in greater detail.

6. Casing crack like this generally is visible to a borescope technician looking inside the 10th-stage extraction cavity

Rodger Anderson, manager of GT technology for DRS Technologies Inc, told the editors he has seen this type of failure in many Frame 5s over the years. He said it is the result of a gray cast iron casing weakened by (1) corrosion, (2) the uplift loading on the ligament area created by airflow through the compressor, and (3) the numerous start/stop cycles associated with peaking service. Keep in mind that gray cast iron has poor tensile and fatigue properties.

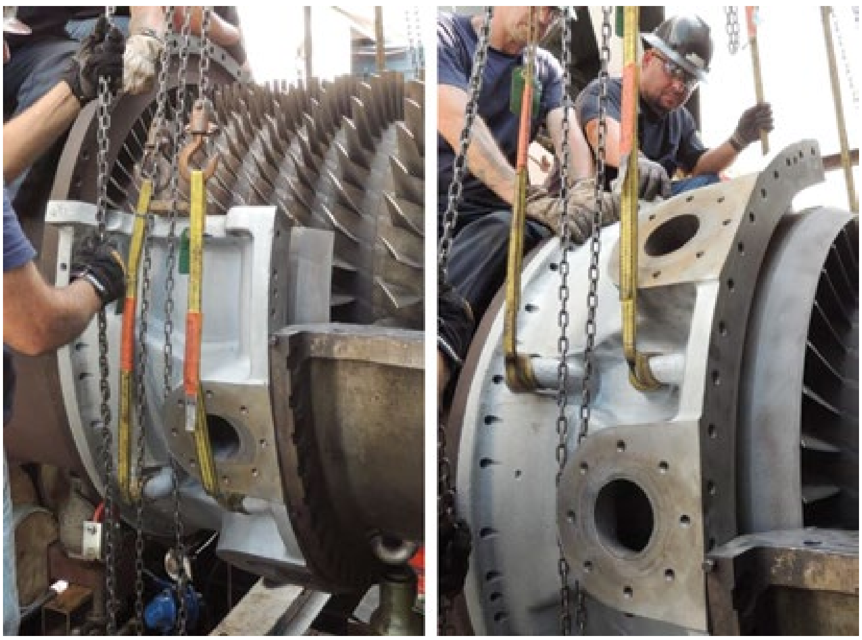
The casing cracks before failure, Anderson continued, and the vane loading will propagate the crack. Thus regular checks of casing condition in the extraction cavity during borescope inspections can warn of impending failure (Fig 6) and enable corrective action before serious damage occurs.

Industry experience with cracking of the ninth-stage hook fit is that it can be expected on peaking units with more than about 1000 starts/5000 service hours over a nominal 30-yr period. TVA's 16 dual-fuel peaking Frame 5Ns (a/k/a Nancys) at one site were beyond that, approaching 40 years of service; in round numbers they averaged 2000 starts/6000 operating hours. Plus, two engines in this group had suffered forced outages because of in-service hook-fit failures.

The utility's original repair technique required performing a major inspection with the unit rotor removed to access the compressor casings for hook-fit repairs—a costly approach. With outages planned for the remaining 5Ns at this site by the end of 2019, an alternative solution was sought to reduce outage cost and duration, and still provide a quality hook-fit repair.

Industry sources suggested a less intrusive method, which eliminated the need to remove the rotor to make hook-fit repairs. These are the steps:

- Remove the upper half of the forward and aft compressor casings.
- Roll out the lower half of the aft



7. Rollers are bolted to the lower half of the compressor case to guide and support its removal

compressor casing (Fig 7).

- Machine the ninth-stage hook fit offsite.
- Bolt the patch ring in place axially.
- Reinstall the lower-half aft casing.
- Reinstall the upper half of the forward and aft compressor casings.

Six patch rings already have been installed using the rotor-in technique (Method 2) at about one-third the cost and one-third the duration of the original method. Even in cases where the rotor must be removed, the speaker recommended pulling the lower half of the aft compressor casing to machine the hook fit. This allows bolting together both casing halves and machining a 360-deg patch ring, thereby reducing the risk of radial clearance issues.

Lessons learned included the following:

- Weld and grind flush axial patch-ring bolting.
- Where multiple units are involved, project synergies can reduce cost and schedule.
- Secure compressor stator vanes into the casing before rolling out the lower half.

CT-Tech™

A unique feature of each CTOTF meeting is a half-day CT-Tech™ workshop, designed to address some of the plant-level training needs of the rapidly evolving industry. This session, the brain child of the organization's proactive leadership committee, provides expanded instruction and training in plant operations and design theory on user-identified subjects at no additional cost to registered attendees.

"Fundamentals of Combined Cycle O&M" was the title of the "course" presented at the spring 2015 meeting by William Lovejoy, PE, director of engineering for NAES Corp. He has 31 years of experience in doing just about everything related to powerplant design, operation, maintenance, and management—mechanical, electrical, and I&C. In his day job, Lovejoy is the primary technical resource for nearly a hundred powerplants representing over 300 individual generators and prime movers.

Lovejoy presented for about an hour on each of the three topics listed below and led discussions in each of those areas to be sure attendees had their questions answered.

- Electrical basics.
- Air side of HRSGs.
- Steam/water side of HRSGs.

The electrical portion of the workshop focused inspection of isophase duct maintenance, generator stator protection, operation of metalclad switchgear, and valve-regulated lead/acid batteries (VRLA).

Isophase duct. He recommended annual inspections of isophase duct and using an engineering drawing and photos showed where to look for problems. Expansion joints are prone to cracking on cycling units, Lovejoy said, because they typically are designed for 1000 cycles. It doesn't take long to get there on a daily-start unit. Also, verify that drains are clear because water will accumulate over time and freeze in winter. If you inadvertently ground isophase bus in a second spot you'll burn off the paint, the speaker noted. Infrared thermography under load also will identify a second ground.

Generator stator protection. Lovejoy suggested that everyone review their generator protection schemes to verify 100% stator ground protection. Historically, he said, full protection was not believed necessary by some designers because damage required two faults and the likelihood of occurrence was low. However, recent losses have at least some of the naysayers thinking otherwise. Given that technology has reduced significantly the cost of 100% stator coverage, it's prudent to increase the level of protection.

Metalclad switchgear operation. A recent arc-flash event occurred when a 13.8-kV breaker was racked-in while closed. Part of the incident focused on the indication of breaker position. The breaker was closed and the physical evidence proved it was closed, but everyone involved saw an "open" indication. Suggestion was for plant management to review breaker operating procedures with all employees qualified to operate this equipment and to identify alternative methods for determining breaker position independent of indication flags.

VRLA batteries have been known to self-destruct when placed under sudden high load. They will fail in an open-circuit condition and not supply power to the emergency loads. In many powerplants, the DC battery banks provide emergency power to the backup lube-oil pumps—a sudden high load. In one instance involving VRLA batteries, lube oil was not supplied to the steam turbine and all bearings were damaged. A risk analysis seems prudent for those relying on VRLA batteries.

HRSGs. Lovejoy spent quality time discussing HRSG cleanliness and the appropriate time for cleaning finned tubes. The analysis was an economic one. He pointed out that for a 7FA, an increase of 3 in. H_2O in backpressure reduces output by about 1 MW and increases heat rate by 15 Btu/kWh.

The impact of backpressure on firing curves was his next discussion point followed by long-term performance tracking. The latter showed by way of plotted data what could be expected in terms of recoverable degradation. Lovejoy's two-dozen slides on the importance of drum level and how to assure accuracy in its measurement presented information that most in the room probably had not seen previously. You can access this information in the CTOTF Presentations Library.

Battery safety

As he approached the podium, Michael O'Brien, technical services manager of Nolan Power Group LLC, asked attendees at CTOTF's Spring 2015 Generators/High-Voltage Electrical/I&C Roundtable, "Can your turbine or generating plant survive an unplanned or emergency trip without sustaining major damage?" This session, chaired by Moh Saleh, engineering O&M manager at SRP's Desert Basin Generating Station, is responsible for station batteries within the CTOTF organization and O'Brien's goal was to help users ensure their DC systems would operate if and when called upon.

Virtually everyone in the room was aware that major damage to critical equipment was likely if station batteries and the associated direct-current (dc) system failed to adequately support the emergency lube-oil and seal-oil pumps and associated equipment following a trip.

O'Brien began with brief descriptions of vented lead-acid (VLA) and valve-regulated lead-acid (VRLA) batteries, the two types typically found in powerplants. He then discussed safety, maintenance practices, inspection goals, and testing. Users can access the speaker's presentation in CTOTF's robust Presentations Library (www.ctotf.org).

The safety portion of the presentation included a well-received perspective on the hazards plant personnel should be aware of before tackling any battery tasks. Here are some bullet points:

- Stationary batteries can pose an electrocution hazard. Voltages may range from 24 to more than 600 Vdc, short-circuit currents from about 1500 to more than 40,000 amps.
- Most, but not all, stationary batteries are intentionally isolated from earth ground. Communication systems and some high-voltage (HV) UPS batteries are grounded.
- The electrolytes used in lead-acid and NiCad batteries are corrosive and will attack human tissue. Eyes and mucus membranes can suffer permanent catastrophic damage when exposed to electrolyte. First aid following exposure: Immediately flush the affected area with clear water for at least 15 minutes; then seek medical attention. Skin exposed to electrolyte should be flushed with clear water.
- All flooded cells (lead-acid and NiCad) produce a highly explosive mixture of hydrogen and oxygen. Always consider the air space inside a cell to have an explosive atmosphere. Functional flame arresters should be installed in stationary batteries. Avoid vent manifolds because they link the explosive air spaces in each of the cells served by the manifold and one ignition source can cause all cells to explode.
- Most injuries associated with batteries are weight-related. Be sure to use proper lifting techniques and equipment in good repair. Best practice: Restrain cells during movement.

Maintenance. O'Brien identified the applicable IEEE/ANSI standards at the beginning of his segment on battery maintenance programs: VLA, 450-2010; VRLA, 1188-2005; NiCad, 1106-2005. He explained that these standards reflect the *minimum* recommended practices and stressed the need to have knowledgeable personnel schooled in safe work practices performing the maintenance. O'Brien said proper maintenance will prolong battery life and help assure the battery can satisfy its design requirements.

His "Golden Rule" for success:

Maintenance must be regular, be consistent, follow standard procedures, be well-documented, and address the specific needs of the battery installed; all data obtained must be corrected to standard industry references. Additional points made:

- All inspections should be made under normal float conditions.
- Specific-gravity measurements are not meaningful during recharge or following the addition of water; also, they must be corrected for electrolyte temperature and level. The true level correction factor varies with each different model cell and must be obtained from the battery manufacturer.

Inspection. O'Brien offered the following guidelines for a general inspection of station batteries:

- Conduct monthly or more frequently.
- Measure float voltage at the battery terminals with a calibrated digital voltmeter.
- Check the battery, rack, and battery area for cleanliness and general appearance.
- Measure charger output current and voltage.
- Check electrolyte levels.
- Verify there is no electrolyte leakage and there are no cracks in cell jars/covers.
- Check for evidence of corrosion.
- Obtain pilot-cell specific gravity, electrolyte temperature and cell float voltage.
- Record ambient temperature and check the condition of ventilation equipment.
- Measure the float current of VRLA if installed.

The speaker went on to provide checklists for quarterly and annual inspections by battery type. You can obtain these by accessing O'Brien's presentation in the CTOTF Presentations Library. The final segment of the presentation provided a roadmap for capacity testing.

Environmental updates

An outstanding feature of CTOTF meetings is the organization's environmental and NERC/FERC regulatory coverage. In a single day at each conference, plant and asset management personnel can come up to speed on the laws and regulations impacting equipment O&M—no shortage of material here. Perhaps the best part of the half-day Environmental Systems and NERC/FERC sessions (a/k/a roundtables) is you can understand what you are being told from the podium. Legalese is not spoken in these forums.

Kimberly Williams, who manages environmental permitting and compliance for NV Energy, chairs the Environmental Systems Roundtable, traditionally held on Tuesday morning at CTOTF's spring and fall conferences. An electrical engineer by education, she came to the utility in 2005 from the oil and gas industry where Williams advised on environmental matters in California.

John Horishny, who manages compliance with NERC 693 Reliability Standards for 35 generating facilities in EthosEnergy Group's portfolio, chairs the NERC/FERC Roundtable on Tuesday afternoons. His day job includes monitoring the activities of the eight NERC regional entities.

Williams split her session at the spring 2015 meeting between water and air interests. Gas-turbine users generally are unfamiliar with water regulations, so she compiled a valuable backgrounder, "New and Upcoming Water Regulations: Why you should care." It covered Section 316(b) of the Clean Water Act (CWA), proposed federal Effluent Limitation Guidelines (ELGs), and the proposed Waters of the United States (WOTUS) rule.

CWA Section 316(b). A quick read of the highlights in Williams' presentation should help you identify which of these regs to post on your white board for further investigation. The chair began by explaining the purpose of the 316(b) revision, which became effective Oct 14, 2014: Reduce impingement and entrainment of fish and other aquatic organisms at intake structures used by power generation and manufacturing facilities to withdraw cooling water from WOTUS. Details are in Title 40 of the *Code of Federal Regulations,* Parts 122 and 125 (subparts I, J, N).

Damaris Negron, the environmental manager for EcoElectrica LP, an LNG-fueled combined-cycle cogeneration plant located in a sensitive ecosystem on the southern coast of Puerto Rico, who followed Williams at the podium, estimated that about 1000 existing facilities (about half powerplants) are affected by 316(b).

Those affected, Williams continued, would have or require an NPDES permit, have a design intake flow greater than 2 million gallons per day (mgd), and use at least 25% of that water for cooling purposes. If you need a refresher on the National Pollutant Discharge Elimination System, it is the permit program that controls water pollution by regulating point sources discharging pollutants into WOTUS.

Williams next discussed compliance options—such as a closed-cycle recirculating system and daily monitoring of intake flows, velocity limits through intake screens, etc—and requirements of the statute. The scary revelation: Even if 316(b) is not applicable, the permitting authority still can impose requirements on a case-by-case basis. Information on compliance deadlines closed out this portion of the presentation.

Dig deeper on the material presented by Williams and other speakers cited in this article by accessing the PowerPoints of interest at CTOTF's Presentations Library.

Federal Effluent Limitation Guidelines, originally promulgated in 1974 and last revised in 1982, established technology-based effluent discharge limits (read 40 CFR 423). Williams said EPA proposed revisions on Apr 19, 2013 to account for powerplant technology improvements over the last three decades and to address changes in wastewater composition resulting from the widespread installation of air pollution controls.

Regarding applicability, ELGs apply to any steam/electric unit with an NPDES permit. Proposed revisions apply to new and existing units that use a fossil fuel, fuel derived from fossil fuel, or nuclear fuel "in conjunction with a steam/water system to generate electricity as the predominant source of revenue."

EPA proposed eight options for setting the new ELGs, each a matrix of technology-based standards for seven separate waste streams. All apply to coal-fired units, one—non-chemical metal cleaning wastes—to plants powered by gas turbines (GTs).

Examples of non-chemical metal cleaning wastes pertinent to GT plants identified by Williams: compressor and condenser cleaning wastes. ELGs include limits for iron, copper, total suspended solids, and oil and grease. The way to avoid this ELG is not to discharge any of these wastes, meaning combined cycles with zero-liquid-discharge (ZLD) systems are not affected.

The final rule was expected by Sept 30, 2015; the proposed ELGs would be phased in between 2017 and 2021 at the time of NPDES permit renewal.

WOTUS rules bear watching. Consider that the Clean Water Act was enacted in 1972, and Supreme Court cases in 2001 and 2006 raised questions about which waters were WOTUS, you can only imagine how difficult the acronym is to define. The latest attempt by EPA and the US Army Corps of Engineers on a definition was proposed Apr 21, 2014. The public comment period, which ended last November, revealed how contentious things WOTUS are. The "final" rule is expected shortly. Editors' suggestion: Access Williams' presentation in the CTOTF library and read through her WOTUS slides while relaxing with an adult beverage.

Given NV Energy's desert location and reliance on air-cooled combined cycles, Williams has limited direct experience with 316(b) requirements and compliance options. So she invited participation by EcoElectrica's Negron, a chemical engineer and environmental psychologist by education, who spends a significant portion of her workday interfacing with EPA's CWA Rules 316(b) and 403.

Negron's case study, supported by spectacular underwater photographs illustrating how this award-winning combined cycle guards the marine environment against degradation and protects sensitive ecological communities, was highly regarded by attendees. The plant's compliance with 316(b) and 403 are critical to its operation. Keep in mind that if your plant must comply with Rule 403 and it doesn't meet the requirements, no NPDES permit will be issued.

Maintaining air emissions within regulatory limits was addressed by Joseph Spahn of Johnson Matthey SEC LLC and Jeff Bause of Groome Industrial Service Corp. Spahn, a chemical engineer by education who is responsible for ensuring his company's catalyst design solutions are in lock-step with customer needs, began with a review of CO and SCR catalysts and their performance goals. Next he explained by way of equations how catalysts are designed, and then spent several minutes reviewing catalyst testing procedures and how to plan a meaningful test program—all geared to optimal use and life management.

Bause, who heads up Groome's HRSG maintenance and industrial cleaning divisions, spends the better part of his professional time at powerplants. He quickly summarized the reasons for SCR and CO maintenance and the reasons for cleaning HRSG heat-transfer surfaces, ammonia injection grids, and ammonia vaporizers, in the process describing the procedures required for success.

Several brief case histories illustrated the economic benefits of catalyst care. At a 2 × 1 501G combined cycle, Team Groom removed one of the two layers of SCR catalyst, then cleaned and repacked both layers. Results: A 2.5-in.-H_2O reduction in backpressure, improvement in NO_x removal to more than 85%, and a reduction in ammonia consumption of nearly 1 gpm.

At a 2 × 1 501F plant with a single layer of SCR catalyst, the ammonia vaporizer, ammonia injection grid, and catalyst were cleaned, and the SCR repacked. Results: NO_x emissions were reduced from 2.2 to 1.7 ppm and ammonia consumption dropped from 192 lb/hr to 144.

Deep-module tube blasting of six tube-bundle faces at a 1 × 1 7FA-powered combined cycle reduced backpressure from 17.5 to 10 in. H_2O. Backpressure dropped by 7.5 in.

At an earlier CTOTF meeting Gale F Hoffnagle, senior VP/technical director, TRC Environmental Corp, and Williams offered valuable guidance to plant managers for navigating the veritable minefield of environmental rules, and for dealing effectively with intervenors. It's unlikely that any plant director, asset manager, or generation executive who attends a CTOTF meeting understands intervenors, and the regulatory processes they use to achieve their environmental objectives, better than Hoffnagle.

His professional career began before EPA was created, which gives him a leg up on most of those serving the electric-power industry today. Plus, he holds a BS in Meteorology and Oceanography, an MS in Meteorology, an MBA, and is a Certified Consulting Meteorologist (CCM) and a Qualified Environmental Professional (QEP)—collectively enabling Hoffnagle to understand and address many environmental issues facing generating facilities.

The consultant told attendees at beginning of his presentation they should expect challenges to virtually every Prevention of Significant Deterioration/New Source Review permit application—whether by environmentalists on global-warming grounds, Nimby residents, or others. He added that project naysayers do not differentiate between new greenfield projects or modifications to existing sources; also, all generating assets burning fossil fuels are targeted, gas gets no pass.

Hoffnagle said intervenors will use all procedural and technical issues at their disposal to stop, delay, or make your project uneconomical. They will demand (1) permitting steps be followed to the letter of the law and (2) consideration of environmental causes. This typically means pressing for the following:

- Use of Best Available Control Technology—that is, a combined-cycle facility in lieu of a simple-cycle machine, to minimize CO_2 emissions. BACT for NO_x is selective catalytic reduction (SCR) and a virtual given for all gas-turbine projects today. Expect attacks on any BACT determination in your permit application, Hoffnagle said.
- A year of preconstruction monitoring to establish background concentrations of pollutants. The states and applicants have avoided this requirement for three decades, the speaker noted, by declaring what the background concentrations are based on any available monitored data. The EPA methodology for determining how and when existing data can be used in support of a permit was written more than 30 years ago and is not helpful.

A year obviously is a long time to wait before filing a permit application. Hoffnagle suggested you may be able to reduce the required sampling time by defining the season when maximum concentrations occur. For example, PM2.5 concentrations are highest in the summer. A sticking point could be timely approval of a monitoring protocol, which can be compromised by poor admin processes in EPA offices.

- Modeling to assure compliance with National Ambient Air Quality Standards.
- An evaluation of the formation of secondary particulate matter and ozone downstream from the stack.
- Control of emissions during startup and shutdown activities and malfunctions.
- Protection of national parks and wilderness areas.
- A maximum of emissions monitoring.

Hoffnagle mentioned that the issues surrounding PM emissions from gas turbines burning either gas or oil is becoming highly contentious. The EPA and states are focusing on reducing PM2.5 in all areas, but especially urban ones. The emissions rate and the appropriate demonstrations of compliance have become an issue, the speaker said.

He added that the difficulty of sampling PM2.5 because of the low emissions rates and the variability in emissions at less than the maximum firing rate are subjects requiring considerable study. Vendor guarantees are not sufficient.

Hoffnagle stressed the significant amount of time and effort it takes to defend a permit to construct and operate today. He discussed the following additions to what engineers might consider a realistic schedule for construction and commissioning if a permit is appealed by intervenors:

- If a construction permit requires a simultaneous operating permit (Title V), then appeals to EPA may run their course (105 days).
- All states have an administrative appeals process, which is akin to a lawsuit in their legal formality. An appeal may take a year, although some states have a 120-day limit. Don't expect the Administrative Law Judge to support a power producer.
- Some states will allow construction while an appeal is in progress, most will not.
- Next stops: EPA Appeals Board, then court.

Looking ahead. The easiest thing for intervenors to demand is more monitoring, reporting and recordkeeping (MRR), Hoffnagle said while wrapping up. They base this on a lack of trust and the state's natural proclivity to demand more MRR. The intervenors are coming, he stressed, making the following observations and suggestions:

- Expect more challenges (PSD and Title V).
- Expect the intervenors will use all the tools available to stop your project.
- Don't skip over, or gloss over, any steps in the permitting process. You will get caught.
- Have counsel involved from the beginning.
- Plan for delay and cost.

Vice-Chair Williams' day job puts her at the crossroads of environmental rules and plant operations. She has a unique perspective among CTOTF members and offers valuable guidance to those on the firing line behind the plant fence. Her presentation illustrated *some* common compliance issues that she has been exposed to.

Williams noted at the beginning of her remarks that a corporate culture of compliance is critical to success, pointing out that noncompliance can adversely impact corporate goals, employee compensation, and the company's reputation and value. She began with inspections and audits, stressing the following:

- Be prepared. First impressions are important, files that might be required should be readily accessible, and personnel interfacing with inspectors/auditors should be knowledgeable, have a positive attitude, and communicate well. Good housekeeping is a big plus.
- Control of contact points.

- Take good notes. Who inspected? Reason for visit? What did the auditors/inspectors look at? What documents did you give them? What did they say? Did they identify any noncompliance issues?

After the visitors depart, resolve any identified problems as soon as possible and document the resolution. If need be, take issues to a higher level. Don't forget to ask for a copy of the auditing agency's internal report.

Williams mentioned the value of conducting self-audits before regulatory personnel visit—to identify and resolve obvious issues beforehand. There's a fleet benefit here as well: If an issue is identified at one plant, assess exposure at the company's other facilities.

To assist in assessing your plant's environmental culture, Williams suggested evaluating answers to the following questions:

- Who is involved in environmental incident investigations?
- Are near misses identified and communicated?
- Is there an environmental committee owned by plant personnel (not corporate environmental staff)?
- Does plant management actively participate in environmental meetings and training?
- Are employees recognized for environmental performance?
- Do supervisory personnel understand their responsibilities with regard to environmental compliance?
- Are targeted environmental programs developed and implemented at the plant?
- Does engineering consider environmental requirements when designing/modifying plant systems and equipment.
- Do new employees receive environmental orientation?
- Are plant environmental performance results posted for all to see?

Williams also offered compliance guidance in the following areas of environmental concern, among others:

- Spill prevention, control, and countermeasures: the rules, a viable plan, spill kits, secondary containment, waste pad management, etc.
- Hazardous wastes: What category is your plant in? What's required to comply with regulations?
- Storm water: requirements, permits, pollution prevention plan, maintenance.
- Training.
- Compliance tracking.
- Environmental ownership of non-generation facilities.

Get the details by accessing the vice-chair's slides in the CTOTF Presentations Library.

NERC/FERC

Horishny's session was arranged much like a workshop with John Ballentine, director of cybersecurity and compliance for HPI LLC, doing the heavy lifting for which he is well-qualified. He presented on the following topics and conducted open discussion sessions after each:

- NERC Critical Infrastructure Protection v.5: standards and compliance timelines. CIP v.5 covers the details, tight schedule, and general applicability guidelines for this extensive set of regulations, which will be unleashed on the industry over the next two years.
- NERC Reliability Assurance Initiative. RAI requires entities to maintain an extensive compliance-control environment; how well they do this will determine NERC audit frequency and scope.
- FERC/NERC regional super-audits. The joint-agency compliance audit, recently announced, is important for powerplant owner/operators to understand. Lessons learned about planning, preparing for, and processing through the super-audit action is valuable for resource planning at the facility and corporate levels.
- Risk-based registration. Important, but for a good reason. Risk-based regulation affords certain smaller entities the opportunity to significantly shrink their regulatory footprint and compliance budget.

By way of professional background, Ballentine has over two decades of experience in the energy industry, including corporate and consulting roles managing cybersecurity and FERC/NERC compliance for power generators. He has more certifications after his name than British loyalty—specifically:

- CISSP, Certified Information Systems Security Professional.
- CISA, Certified Information Security Auditor.
- CCEP, Certified Compliance and Ethics Professional.
- GLEG, Certified Information Law Specialist.
- CSSA, Certified SCADA Security Architect.

It is impossible to summarize Ballentine's course notes, encompassing more than 170 information-dense slides, into an article of value to asset management and powerplant personnel. The only way for you to gauge what you have to learn, and how quickly, is to access the speaker's presentations in the CTOTF Library. CCJ

Most popular

The headline refers to the 7F engine, the world's most popular large frame gas turbine, based on information in **CCJ's** files. To put this in perspective, consider that the 7F fleet is nearly double the size of the Siemens D5, D5A, F, G, and H fleets combined. So it should not surprise that the world's largest meeting of frame gas-turbine owner/operators is hosted annually by the 7F Users Group and the most successful entrants in **CCJ's** Best Practices Awards program are combined-cycle and peaking plants powered by 7F engines.

The organization's 2015 conference, held at the Sheraton Denver Downtown, May 11-15, attracted nearly 300 users and more than that number of commercial attendees representing the 122 companies participating in the vendor fair over two evenings. The group formed in November 1991, when there was only one 7F operating in the world. The first meeting hosted 14 users from four generating companies.

This year's event was an unqualified success by every measure, except for the weather. Sheila Vashi and her team of meeting professionals at SV Event Management, and the all-volunteer steering committee (photo), couldn't convince the weather gods to deliver a warm, sunny day for the annual golf tournament. Snow and mud forced the first cancellation of that event anyone could remember. Mostly vendors were affected, as you might imagine.

Steering Committee Chairman Robert LaRoche of SRP noted in his opening comments that the 286 user attendees broke the previous record of 246—a 16% increase. In that total were 40 international owner/operators representing Brazil (Petrobras and Eneva, a subsidiary of Germany's E.ON), Japan (Chubu Electric and Osaka Gas), Korea (Korea Southern Power, Korea Western Power, and SK E&S), Mexico (Iberdrola), Saudi Arabia (Jabail O&M, Jabail Water & Power, Saudi Electric, Tihama Power), Taiwan (Chiahui Power), and United Kingdom (RWE npower).

7F committee chairs serve a one-year term. At the close of the Denver meeting, Ed Maggio of TECO Energy moved into the chairman's chair, and Duke Energy's Clift Pompee into the second seat, to start planning the 25th anniversary conference at Orlando's Rosen Shingle Creek, May 9-13, 2016. Calpine Corp's Peter So continues as treasurer.

The steering committee worked with the OEM and other key vendors to pack so much gas-turbine technology into the four-and-a half-day program those who made it to the end needed the weekend to recuperate.

2016 7F steering committee. First row (l to r): Robert LaRoche, *SRP*; Ed Maggio, *TECO Energy*; Clift Pompee, *Duke Energy*; Luis Barrera, *Calpine Corp.* Second row: Eugene Szpynda, *NYPA*; Bryan Graham, *Entegra Power*; Jeff Gillis, *Exxon Mobil*; Peter So, *Calpine Corp*. Third row: Ed Fuselier, *Competitive Power Ventures Inc*; Sam Graham, *Tenaska Inc*; David Such, *Xcel Energy*. Fourth row: Peter Margliotti, *GDF Suez Energy North America*; Richard Clark, *EthosEnergy Group (Gila River Power Station).* Camera shy: Paul Whitlock, *Dominion Resources*; Art Hamilton, *Emera Energy*; Justin McDonald, *Southern Company Generation*; Bob Holm, *OxyChem*

The non-stop event began Monday morning with attendees having a choice between HRST Inc's F-class HRSG Spotlight Session and a tour of Xcel Energy's Cherokee 7FA.05 combined cycle, the first of this model constructed in the US. See the following article on Woodbridge Energy Center (p 92), expected to be the third Dot 05 to achieve commercial operation.

HRST's Craig Dube and Jonathan Aurand presented on HRSG tube sampling for long-term reliability, HRSG drains: problems, arrangement and control, and online HRSG condition assessment checks (see article included in this 7F report). Monday afternoon's feature was an eight-presentation GE controls workshop that ran from 1:30 until after 6 p.m. with only one break.

The Tuesday and Wednesday programs were user-only and included presentations by owner/operators and open discussion before the afternoon breaks. Invited vendor presentations followed the breaks on both days. They were arranged in two 45-min sessions, with three product/services suppliers presenting in parallel during each period. A vendor fair closed out each day's activities at 8:30 p.m.

The 7F Users Group traditionally features more presentations by owner/operators than any user organization attended by the editors. This year was no different, with 10 presentations on Tuesday covering the compressor section, safety practices and lessons learned, performance and controls, and auxiliaries. On Wednesday there were another seven user presentations, on the combustion and turbine sections, and generators. Plus a 90-min, "Top-10 Issues" open discussion session. Summary coverage will be presented in upcoming issues.

Themes of the dozen vendor presentations boiled down to these: inspection, high-voltage electrical, reliability upgrades, HRSG and emissions control, repair of hot parts, and compressor solutions.

Thursday was GE Day. More than a

dozen of the OEM's experts, armed with nearly 200 slides, covered compressor updates, cold-day operability and fuel variation, HGP updates, accessories reliability and TIL updates, DLN 2.6+ tutorial, new repair technologies, monitoring and diagnostics, and other subjects.

Friday was reserved for a new four-hour offering, 7F Grad School, "taught" by the OEM's engineers. It offered three concurrent sessions from 8 a.m. to 9:45—a deep dive on systems performance and operability, thoughts on plant reliability, and market dynamics for engineers. The second option investigated best practices for auxiliary systems and operation with the goal of achieving world-class performance. The last attempted to make engineers bring greater value to their companies. For example, the interactive session explored external dynamics—which may be driven by technical, financial, and/or social policies.

The first two options were replayed in the 10 a.m. to 11:45 time slot with the market dynamics option replaced with "The Road to 200 MW and Beyond."

Best practices

This year, 13 plants generating power with 7FAs were recognized for their accomplishments in **CCJ's** Best Practices Awards program. Two, Gateway Generating Station and Gila River Power Station were at the top of the Class of 2015, receiving Best of the Best Awards. Their accomplishments are profiled in the 1Q/2015 issue on your bookshelf.

Three plants—Emery Generating Station, Riverside Generating Station, and Green Country Energy—were recognized by industry peers at the 7F meeting in Denver. Jim Fleming accepted the awards for Alliant Energy's Emery and Riverside plants (p 94), J-Power USA's Makoto Kaneko for Green Country (p 96). Effingham County Power's entries follow on p 98.

Thumbnails of the best practices submitted by the other 7FA generating plants recognized in the 2015 program are immediately below. Details will follow in upcoming issues.

■ Jack County Generation Facility
Operation and Maintenance
- Combating winter weather readiness in Texas.

■ Essential Power Newington:
Operation and Maintenance
- Evaporative-cooler relocation improves maintainability.
- Smart drains reduce potential for piping damage.
- Upgrading battery technology and system contributes to increased safety and reliability.

Performance Improvements
- Gas-turbine liquid fuel recommissioning enhances reliability.

■ Faribault Energy Park, operated by NAES Corp
Fast Starts
- Steam-turbine warming blankets offer increased operational flexibility and reduced startup time.

Workforce Development
- Development of a checklist and subsequent staff training to effectively write procedures greatly reduces the risk of human errors and system failures.

■ Colusa Generating Station, Pacific Gas & Electric Co
Operation and Maintenance
- Engineering study to assess cycling impacts helps prioritize future expenditures.
- Online monitoring of dissolved gases in transformers ensures safe and reliable operation.

Performance Improvements
- Startup emissions calculator enables compliance.

■ Hartwell Energy Facility, Oglethorpe Power Corp
Safety
- Improved stairwell design provides safe, efficient access to turbine and generator.

■ MEAG Wansley Unit 9, operated by NAES Corp
Operation and Maintenance
- Alternative pump modification saves labor and crane cost.
- New LED plant lighing reduces costs, enhances worker safety.

Safety

- Weekly eyewash/shower station inspections safeguard workers in case of emergency.
- Reverse-osmosis system redesign eliminates ergonomic risks to operators.

■ Nueces Bay Energy Center, Topaz Power Group

Performance Improvements

- Replacement of traditional clip board and pen with tablet and stylus allows operators to log rounds data digitally, making collection and troubleshooting quick and efficient.

■ Washington County Power, operated by Consolidated Asset Management Services

Operation and Maintenance

- Test switches installed on the CEMS control panel enable operators to conduct monthly test quickly and safely without disrupting the plant's electrical system.

Safe work practices

The 7F Users Group steering committee gave its *Safety Practices and Lessons Learned* open forum the respect deserved by positioning it in a prime-time spot on the 2015 meeting agenda and by assigning one of the industry's most respected discussion leaders and safety experts, Jeff Gillis, as the session chair. Gillis, the gas-turbine technology lead for ExxonMobil Research & Engineering Co, is both a member of the 7F steering committee and the co-chairman of the Frame 6 Users Group.

This was an open discussion session; Gillis was not there to lecture. His job was to stimulate a give-and-take, help colleagues resolve safety challenges, identify best practices, leave no question unanswered, etc. Fall protection inside the package was brought to the floor first, no surprise there. Package rigidity with the roof off was questioned regarding its load-carrying capability. A user cautioned that tie-offs must be well-engineered because the plant is libel for injuries not prevented by the protection system.

Someone reported difficulties in getting contractor personnel to use fall protection. Everyone in the room knew the answer to that one: "You don't have to use fall protection. Will the next person who thinks they can question the plant rules regarding fall protection please step forward?"

Safety rules are there for a reason and have to be followed no matter what any plant employee or contractor thinks, a steering-committee member said. He recalled a time when a contractor collapsed on the job with all the symptoms of a heart attack. An ambulance was called. By the time it arrived, the person in distress believed he had recovered and there was nothing to worry about. He was told he couldn't stay onsite unless he went to the hospital. Reluctantly, he got in the ambulance. Doctors said he would have died had he not come to the hospital for treatment.


Steve Royall accepts Gateway's 2015 Best of the Best Award from CCJ Editor Bob Schwieger (left)
John Walsh receives Gila River's 2015 Best of the Best award for performance enhancement (right)

The discussion migrated to rules for package entry during operation. This is a hot topic of debate industry-wide today. One reason: The OEM strongly recommends *against* package entry when the unit is operating. An audience poll showed plants represented by 79% of the attendees responding to the question, using the group's high-tech wireless polling system, allowed entry during engine operation.

The use of dedicated safety professionals during outages was viewed positively. One attendee said that his plant requires a job safety professional (JSP) for each shift when six or more people are working on the turbine. This person has to know site and contractor safety requirements and OSHA regulations. When disagreements arise, he said, the JSPs for the contractor and owner/operator generally can work things out collaboratively.

Regarding the use of third-party safety professionals, one user said his plant did not find value in doing that and was eliminating the practice. Statistics didn't support paying for this service, he said. Someone on the far side of the room asked for the mic and noted that third-party safety professionals were like any other contractor—some are good, some not. You have to figure it out. Four-fifths of the attendees did not use third-party contractors for this service.

The subject of fire risks associated with work on the air inlet house stimulated some conversation. Far too frequently there's a report of a fire caused by welding on the filter house; dry air filters and evap media ignite quickly. Remove them before cutting and welding. Beware hot halogen lamps as well. Recommended practice: Use only cool LED lighting in filter houses.

At many plants the access door to the filter house is on the first floor and that's the only way to get into and out of the structure. If a worker is on the second or third elevation (access by wall-mounted ladder) in the unlikely event of a fire, he or she could be trapped. Consider retrofitting access doors on each level of your filter house. CCJ

Woodbridge Energy Center, one of three of the first 7FA.05 combined-cycle sites, paid strict attention to the non-sexy stuff that can bite you where it hurts between the construction/commissioning and operating phases of the facility

O&M begins well before first fire

Non-utility combined-cycle facilities often have separate entities for ownership, EPC services, onsite O&M, and long-term care of the gas turbines. While this arrangement may create efficiencies within each function, it can also create gaps among the organizations involved. One of the most important of these gaps occurs as construction winds down and commissioning ramps up.

Most **CCJ** readers are probably familiar with owner and/or O&M teams that lament the lack of collaboration with the EPC team *after* they become mired in consequential issues (and often litigation) which could have been addressed ahead of time. As more facility revenue is earned through performance-based market objectives, avoiding impacts to productivity, reliability, and flexibility becomes paramount.

At the soon-to-be completed Woodbridge (NJ) Energy Center, the operator of record, Consolidated Asset Management Services, created a formal process of walk downs, the intention being, according to CAMS' Ken Earl (and Woodbridge plant manager), to "own" the operation of the facility from day one. What Ken means by "own" is to not be in a position of blaming someone else for punch list items after commissioning.

However you look at the scorecard, Woodbridge (sidebar) may not be the first with GE 7FA.05 gas-turbine operation under its belt, but it probably will be one of three facilities with the earliest industry experience. The sexy advanced GT technology may hog the attention, but it's the mundane components that can bite where it hurts when neglected.

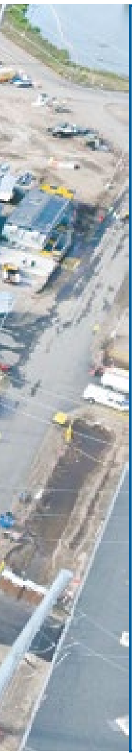
Trust but verify

The CAMS team was put in place and onsite eight months prior to first fire expressly to provide input to construction and EPC. As the EPC construction team completed subsystems, they would be turned over to the EPC startup and commissioning team. The turn-over process required a formal walk down of the subsystem to ensure construction was completed in accordance with design specifications and that the system was ready for operation.

CAMS became involved with the turnover process and organized and implemented a formal process to be used when reviewing systems with members of the construction trades, EPC startup team, and owner representatives. The key objective was to understand how the systems were supposed to have been built and then make sure the facts on the ground reflected the design.

CAMS assembled a package for

1. Large motor-operated isolation valve originally was installed in an obstructed location (left); corrected arrangement is at right



The vanguard of recent combined-cycle facilities

With respect to 7FA.05 pioneers, Woodbridge is in a league with Xcel Energy's Cherokee Generating Station and the Newark (NJ) Energy Center. The **CCJ** editorial team will be taking a deep dive into 7FA.05 O&M experience as it becomes available. Ken Earl commented on a few of the facility's advanced features.

Its GE Mark VIe plant control system takes advantage of model-based control, which avoids fixed constraints and makes the machine more flexible and efficient, as well as auto-dynamic combustion tuning to optimize among stability, efficiency, and NO_x emissions (9 ppm at the GT exhaust flange, 2 ppm at the stack on a 3-hr rolling average).

The unit also will have, in Ken's words, "close to feedforward control" because the firing temperature is no longer fixed and can be adjusted based on a chromatograph-indicated Wobbe Index signal from the fuel system. Humidity control, using direct sensors, is also important to the models.

One of the most prominent 7FA.05 features is the variable stator vanes which also provide flexibility and control capability. That, combined with the first-stage turbine external cooling system, boosts efficiency (6900 Btu/kWh at load). Despite the advanced features, Ken says there aren't that many additional instruments for the O&M team to manage. The GTs will be governed by a contractual service agreement with the equipment supplier; covered maintenance, parts, and refurbishment are the responsibility of the OEM.

This makes sense as Woodbridge is in the earliest phases of this technology deployment, along with the other pioneers. It also is why the CAMS team has been in training since March 2015, with much of it focused on GT training from GE.

In the balance of plant, Ken notes the use of graywater at the facility. While it's supposed to be "good quality," he flags this as a question mark, as the plant is essentially "at the mercy of" the quality of the effluent from the municipal wastewater treatment plant. The facility has an automated strainer system for pretreatment; whether this is adequate to prevent fouling in the cooling tower remains to be seen.

The 27.5-acre site itself is part of a large remediation program and includes space for another 2 × 1 combined cycle. The original ground was cleaned up to a certain level and then covered with two feet of "clean cap" materials. Competitive Power Ventures (CPV), the owner, is responsible for maintaining this cap for the life of the facility. A hydraulic barrier wall and trench system surrounding the facility ensures that groundwater is maintained within the remediation site.

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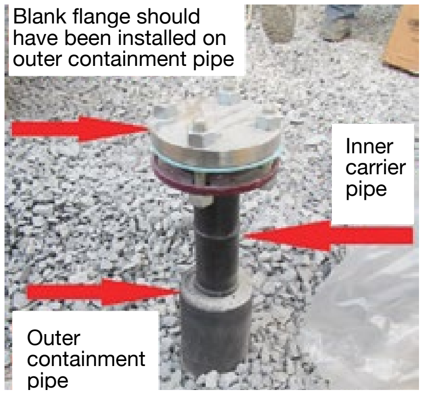
each walk down, including P&IDs, one-line diagrams, design specifications, equipment supplier specifications, and installation procedures. To ensure they were well-versed in the finer points, CAMS conducted a pre-walk down of its own before the formal walk down with all stakeholders.

In this way, CAMS identified issues falling through the gratings. Heat tracing is an excellent example, according to Ken. Woodbridge is an "outdoor" plant in New Jersey, so inadequate installation of heat tracing would impact winter reliability and availability. The PJM power market, where Woodbridge will feed its output, imposes stiff penalties (up to millions of dollars a day) on plants that do not meet their performance obligations in the capacity market. Thus, heat tracing becomes a critical plant subsystem.

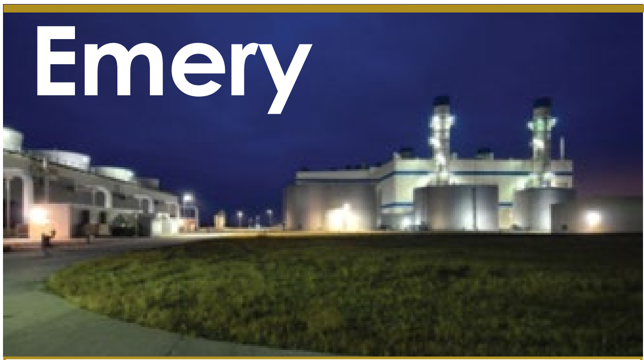
Ken lists these as CAMS' most notable discoveries from the walk downs:

- A large motor-operated isolation valve in the cold reheat system was installed in an obstructed location which would have prevented disassembly because of interference with structural steel (Fig 1).
- Double-walled aqueous ammonia piping was installed with no means of inspecting the interstitial space. The facility drawings indicated inspection ports had been installed to facilitate inspections of the containment pipe, however the carrier pipe (ammonia) was brought above grade to a blind flange (Fig 2). This was identified during a compliance audit prior to ammonia being placed in the system but could have resulted in a serious safety and environmental event.



2. Aqueous ammonia piping with improperly installed flange could have led to a serious safety and environmental event

- The non-segregated phase bus duct between a 4160-kV transformer and the switchgear building was blocking access to inspection doors on the primary switchgear feed, prohibiting routine inspections.
- A boiler feedwater flow element was installed backwards by the EPC.
- Interconnecting piping for the reverse-osmosis (RO) units in the water treatment plant was installed in a location that would prevent or inhibit loading or unloading of RO membranes.
- The auxiliary-boiler feedwater storage-tank drain line was installed without an isolation valve, which could lead to inadvertent, continuous draining.
- Eyewash/shower stations were not in compliance with ANSI standards.
- Over 90 instances were identified of guardrails, handrails, and fixed ladders non-compliant with OSHA standards.
- Heat detectors in the gas-turbine-housing accessory compartment were improperly located against their design temperature ratings. In this case, the equipment was supplied directly by the turbine OEM, underscoring the importance of repeated quality checks.
- The cold-reheat desuperheater intermediate-pressure feedwater lines had no means of isolation from the common feedwater line supplied from each HRSG (which would prevent a single unit outage).
- Similarly, the common condensate feed line to the low-pressure economizers had no means of isolation from the common line supplying each HRSG, which also would prevent a single unit outage.
- In addition, there were literally hundreds of "little things," notes Ken, involving equipment access, construction quality, and design shortcomings which were identified based on prior startup experience at other facilities. "We pushed back on many items, because we treat the asset as our own. Our goal is to ensure all deficiencies are identified and addressed during construction so there are zero punch-list items on day one of commercial ops." CCJ

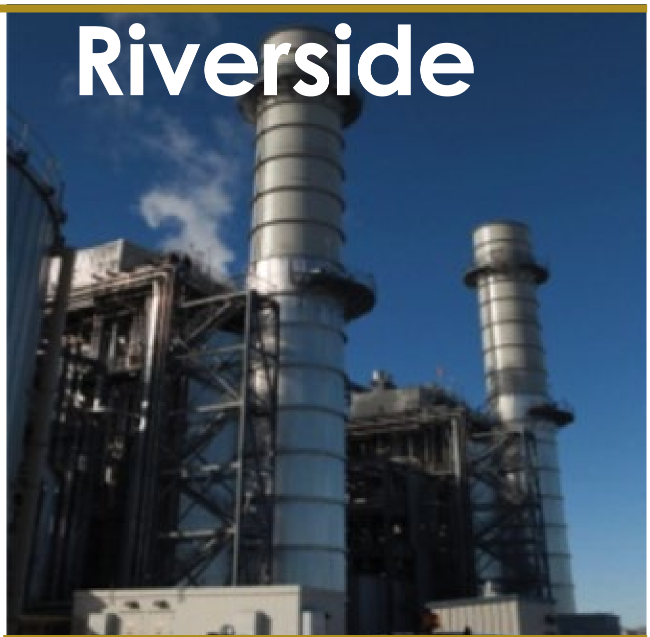


Emery Generating Station

Alliant Energy Corp

600-MW, dual-fuel, 2 × 1 combined-cycle facility located in Mason City, Iowa

Plant manager: Craig Crawford



Riverside Generating Station

Alliant Energy Corp

650-MW, natural-gas-fired, 2 × 1 combined-cycle facility located in Beloit, Wisc

Plant manager: Joe Ell

Rail and lanyard solution protects against enclosure fall hazards

Challenge. Safety is Alliant Energy's top priority. Maintaining a safe work environment during outages can be challenging, particularly so when work inside the gas-turbine enclosure is required. It presents fall and trip hazards above the engine, and a concrete floor. Also, as the condition of the gas turbine (GT) and its related equipment is revealed, outage scope can change dramatically, making it difficult to predict what hazards will exist when, and how to mitigate them proactively.

Solution to this outage safety challenge is to make it virtually impossible for anyone to get hurt inside the enclosure. An innovative rail and lanyard safety solution developed by Alliant Energy, in conjunction with Hy-Safe Technology, contributes significantly to the achievement of this goal.

Fall hazards typically are tackled using one of these two protection methods: a fall-arrest system or a fall-restraint system. The former protects an individual by limiting the fall distance and absorbing the shock of the fall; the latter prevents an individual from falling in the first place, by limiting the technician's travel to a safe distance away from fall hazards. Inside an enclosure, technicians typically work on many areas of the engine, making fall-restraint systems physically impractical.

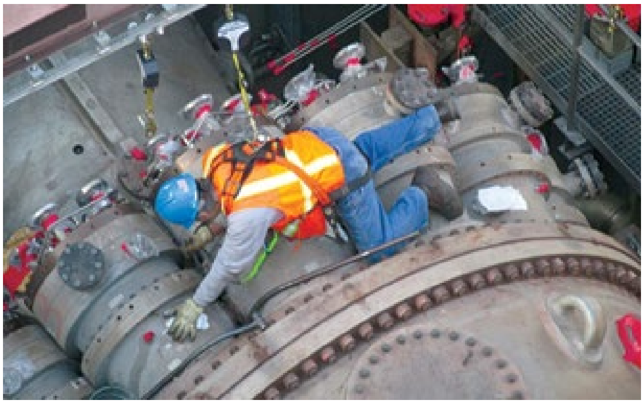
Fall-arrest systems require load-bearing tie-off points, sometimes two per person so personnel are secure at all times as they move around. Also, to maintain a high level of productivity, multiple technicians generally work on the GT concurrently. This is challenging because the enclosure doesn't provide many secure tie-off points. Bear in mind that once the enclosure roof is removed, the load-bearing capability of its sides is greatly diminished, eliminating their value as an effective foundation for tie-off points. The disassembly work itself eliminates some other tie-off points.

Alliant Energy looked for scaffolding/tie-off alternatives to resolve the unique fall hazards presented by enclosure work. The Hy-Safe solution consists of retractable lanyards underneath an engineered rail (Fig 1), shown in use in Fig 2. Fig 3 shows two rails mounted under an I-beam (a/k/a trolley); three retractable lanyards can be installed on each of the rails.

This highly engineered system is designed specifically for fall protection, not for lifting, and is centered over the turbine. Up to six technicians can connect these lanyards to the D-rings on the backs of their harnesses; a breaking mechanism in each lanyard effectively, and independently, arrests any fall that might be experienced. Once the enclosure roof is removed, the existing crane is replaced with the trolley; the crane is reinstalled just prior to roof replacement.

Results. The rail and lanyard solution has proven safe and efficient, and capable of use in any of the company's

1. Two rails are mounted under an I-beam (left); three retractable lanyards can be installed on each of the rails (right)



2. Tethered technician works atop the gas turbine with freedom of movement

3. Alliant Energy's enclosure safety solution consists of retractable lanyards underneath an engineered rail

GT enclosures. It offers these benefits over traditional scaffolding/tie-off alternatives:

- Improves fall protection from a static and reliable anchor point. This practically eliminates trips and fall hazards, provides continuous protection as hazards evolve during an outage, and eliminates the need to reconfigure scaffolding and tie-off points for complete enclosure protection.
- Creates the following productivity, time, and cost improvements:
  - Technicians have the flexibility to do their jobs using safe techniques and positions.
  - Multiple technicans can work around each other easily and productively.
  - Two mechanics can install or remove the trolley in less than an hour.
  - Direct financial benefits are estimated at up to the mid-five-figures per outage over alternatives.
  - The time saving increases unit availability and lowers replacement power costs.
- Allows flexibility for a variety of work, including borescope, combustion, hot-gas-path, and major inspections.

Use of the rail and lanyard system received positive comments from technicians. One remarked, "Best I have ever used. None of the millwrights complained about it at all." Another said there was a steep learning curve, but once the system was in place, it "worked very well and allowed multiple people to be working at heights safely, and it allowed for access along the entire length of the unit with minimal restriction."

Project participants:

Jim Fleming, senior turbine engineer
Mike Cichocki, safety specialist
Colin Beverage, senior environmental and safety specialist
Craig Crawford, plant manager (Emery)
Joe Ell, plant manager (Riverside)

Training future plant leaders for new, ever-increasing challenges

Challenge. The changing of the guard has begun at America's powerplants—Green Country Energy (GCE) included. Highly experienced managers who went through extensive technical and leadership training over the past 30 to 40 years have either recently retired or are planning to retire within a few years.

This leadership "vacuum" has created opportunities for new managers, who face daunting expectations from headquarters that pre-existing positive work cultures and top performance results will continue as before. Adding to the challenge are ever-increasing administrative and regulatory duties which reduce the time managers and supervisors have to focus on their core responsibilities: managing the safe and efficient production of reliable energy.

Solution. Strong leadership skills are required to meet future challenges, making training critical to success. GCE has conducted some measure of leadership training since COD 13 years ago, but personnel changes warrant a more determined effort to properly prepare the plant's new managers and supervisors (photo). A three-year leadership training program was initiated in 2013 with the principal objective of reinforcing plant leadership's long-term shared values, vision, and guiding principles.

The training program focused on "The Leadership Challenge," by James M Kouzes and Barry Z Posner, which details these five practices of an exemplary leader:

- Modeling the way.
- Inspiring a shared vision.
- Challenging the process.
- Enabling others to act.
- Encouraging the heart.

Department managers and supervisors, administrative staff, and lead technicians participated, along with managers from NAES and J-Power USA headquarters. Participants were divided into four groups; each included a mix of technical and supervisory disciplines. Plant Manager Rick Shackelford presented the material and led the discussions. The program began with three training sessions conducted over a three-week period; three additional sessions were held at six-month intervals. A PowerPoint presentation was developed to guide the program.

Green Country Energy

Owned by J-Power USA

Operated by NAES Corp

800-MW, three gas-fired 1 × 1 combined cycles in Jenks Okla

Plant manager: Rick Shackelford

Results. Feedback from participants indicates the training was well-received. In addition to discussing the five practices of an exemplary leader and the plant's shared values, vision, and guiding principles, considerable time was allocated for an open forum. The forum identified numerous plant-level issues and misperceptions and went a long way toward resolving many of them.

It also promoted bonding between supervisory levels and technical disciplines and helped clarify management's priorities and expectations. Finally, it revealed new ideas for dealing with old problems and helped remind the plant manager of the leadership practices he should be modeling consistently.

While it's too soon to assess the long-term benefits of the leadership training, senior managers are confident it will yield measurable improvements in plant operations and

Training initiative in progress. Clockwise from Rick Shackelford, plant manager (at left): Danny Parish, operations manager; Daniel Barbee, contracts administrator; Jim Little, operations team leader; Mike Anderson, maintenance manager; David Rose, maintenance team leader; Linne Rollins, compliance supervisor; and Raegan Robinson, plant administrator reliability. The expected takeaway for new leaders is that they've acquired the tools to continue in the Green Country Energy tradition and produce outstanding performance results for years to come.

Participants:
Michael Anderson, maintenance manager
Danny Parish, operations manager
Daniel Barbee, contracts administrator
Allen Meyer, procurement administrator
Linne Rollins, compliance supervisor
Raegan Robinson, plant administrator
Rick Shackelford, plant manager
Derek Hale, Jim Little, Ewing Jackson, and John Noftsger, lead operations technicians
Dave Rose, lead maintenance technician
Dave Ehler, project manager (NAES Corp)
Paul Peterson, Brian Niven, and Chris Bluse, J-Power USA asset management team
John Hutson, plant manager (Orange Grove Energy Center)

Sharing knowledge via plant-level mini-conference

Challenge. Combined-cycle plants certainly have their share of O&M challenges. Technicians are confronted almost daily with technical issues they're facing for the first time. However, the vast majority of these are not new or unique, and most already have been resolved by others. The challenge is knowing whom to reach out to for help—including plant supervisory personnel, manufacturers, consultants, and your network of user-group colleagues.

Solution. Green Country Energy found one way to share solutions to common technology problems was to establish a "Similar Technology Mini-Conference." During summer 2014, the plant hosted a two-day roundtable meeting focusing specifically on nearby 7FA-powered combined cycles, most of which were operating A-10 or D-11 steam turbines. In all, 27 participants from 11 plants attended. They represented government, utility, and IPP owners.

Attendees embraced the view that sharing solutions to common technical problems creates better-informed, more successful O&M providers. They believed this type of information-sharing would accomplish the following:
- Increase plant availability.
- Reduce the risk of employee and contractor accidents.
- Improve environmental performance.
- Increase efficiency.
- Decrease O&M expenses.

The mini-conference was structured differently from typical users' conferences in that it devoted two days to "shirtsleeves rolled-up" roundtable technical discussions among plant managers, engineers, and O&M managers. The topics included plant safety, environmental compliance, NERC compliance, gas turbines, steam turbines, steam piping and HRSGs, breakers and transformers, cooling towers, water treatment, O&M procedures, equipment major inspection, and control systems.

Participants were fully engaged and forthcoming, which made for lively and insightful sessions. Valuable networking took place among professionals of like disciplines, as well as much note-taking on solutions to long-term issues at the participants' plants.

Results. Feedback from attendees indicated the mini-conference was well-received. Several remarked that it was the best conference they had ever attended, for the simple reason that all topics and discussions focused directly on equipment they operated and maintained. GCE has implemented many of the ideas brought to light and corrected many issues based on discussions with fellow O&M providers at similar plants. Another of the participating plants recently credited information presented at the mini-conference with preventing a forced outage involving approximately 800 MW of capacity.

Participants:
Michael Anderson, maintenance manager
Danny Parish, operations manager
Daniel Barbee, contracts administrator
Linne Rollins, compliance supervisor
Rick Shackelford, plant manager
Jim McConville, division director (NAES Corp)
Dave Ehler, project manager (NAES Corp)
Brian Niven, Makoto Kaneko, Hiroto Shimizu, and Masaru Sakai, J-Power USA

Effingham

Effingham County Power

Owned by Southeast PowerGen LLC

*Operated by Consolidated Asset Management Services**

525-MW, gas-fired, 2 × 1 combined cycle located in Rincon, Ga.

Plant manager: Ken Earl (former), Nick Bohl (current)

*The facility is now owned and operated by Cogentrix Energy LLC.

Plant-specific, in-house calibration procedures

Challenge. Effingham opted to purchase equipment and software needed to perform in-house calibrations. There are over 390 instruments plant-wide that require calibration, including various transmitters and switches. Many of the instruments require annual calibration while some intervals are every two to three years. Because of the infrequency of some calibrations, it is easy to forget the setup and proper method to calibrate. Some of the instruments require a special set up or are not your typical calibrations.

Being a multi-craft plant, everyone is required to be trained in I&C and must be able to perform these calibrations. At the start of the program there were no guidelines or instructions for this. Many questions came up about the proper way to calibrate, so it was decided to develop plant specific procedures/write ups. Sometimes the technicians just need a refresher on the basics. Other times, when troubleshooting becomes necessary, a guideline is helpful. The literature is a helpful reference to those who are getting qualified in I&C.

Solution. A looseleaf binder was created that includes a wealth of information on the calibration equipment, such as Fluke 744, Fisher-Rosemount HART 375, various hand pumps, and ProCalV5 software (Fig 1). Individual procedures are drawn up explaining step-by-step how to complete the calibrations (Fig 2). Drawings and/or instrumentation literature is added to the some of the procedures to clarify the set up.

There is a section that describes the basics of plant instrumentation: Rosemount transmitters, Fisher DVC 6000/6200 controllers. A basic troubleshooting guideline has also been added. All the documentation is saved on our shared drive so it can be viewed and copied as needed. The list of procedures is ongoing and improved as they are proofed.

Below are some of the procedures that have been created:

- Calibrating the Rosemount 3051SMV fuel-gas-flow multivariable transmitters.
- Calibrating the Magnetrol condenser level transmitters.
- Calibrating the CCS seal-oil differential pressure switches.
- Calibrating transmitters with head pressure (wetted legs).
- Calibrating the Mid-West Instrument differential-pressure gages for the BFP strainer.
- Setting up a new transmitter or electronics board module.
- Running an auto calibration on the Fisher DVC6000/6200 series controller.
- Reconfiguring a Rosemount tri-loop.
- Handling calibration issues.

Tabs have also been added for review:

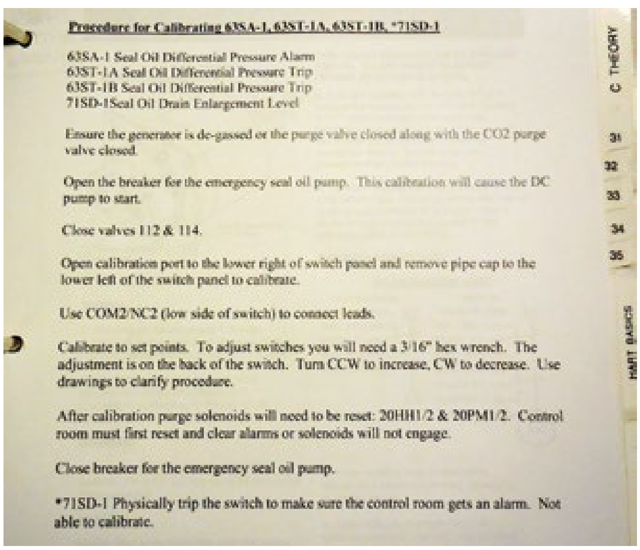
- How to properly set up a transmitter for calibration.
- Thermocouple theory.
- RTD theory.
- Tips and notes of interest.

Results. The technicians now have step-by-step resources to help them to complete calibrations. It is cost-effective to keep the calibrations in-house and eliminates time spent on researching proper set-up.

Project participant: Cheryl Hamilton

1. Calibration equipment used at Effingham includes that shown here (left)

2. Individual procedures explain how to complete the calibrations (right)



Procedure for Calibrating 63SA-1, 63ST-1A, 63ST-1B, *71SD-1

63SA-1 Seal Oil Differential Pressure Alarm
63ST-1A Seal Oil Differential Pressure Trip
63ST-1B Seal Oil Differential Pressure Trip
71SD-1Seal Oil Drain Enlargement Level

Ensure the generator is de-gassed or the purge valve closed along with the CO2 purge valve closed.

Open the breaker for the emergency seal oil pump. This calibration will cause the DC pump to start.

Close valves 112 & 114.

Open calibration port to the lower right of switch panel and remove pipe cap to the lower left of the switch panel to calibrate.

Use COM2/NC2 (low side of switch) to connect leads.

Calibrate to set points. To adjust switches you will need a 3/16" hex wrench. The adjustment is on the back of the switch. Turn CCW to increase, CW to decrease. Use drawings to clarify procedure.

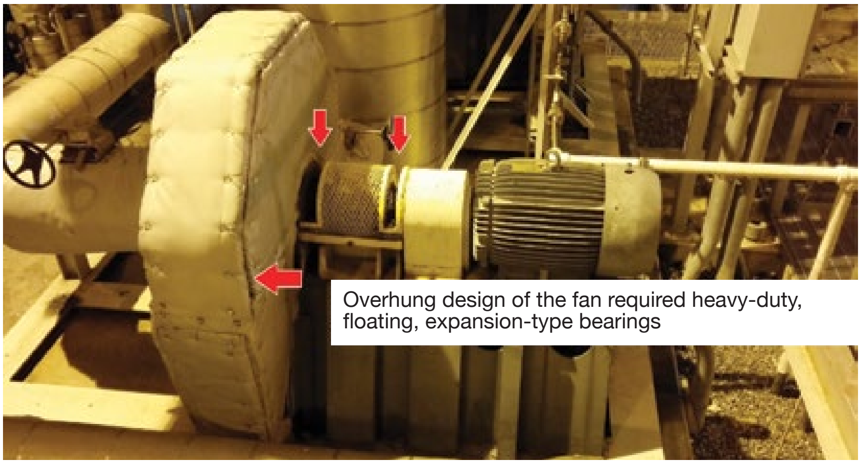
After calibration purge solenoids will need to be reset: 20HH1/2 & 20PM1/2. Control room must first reset and clear alarms or solenoids will not engage.

Close breaker for the emergency seal oil pump.

*71SD-1 Physically trip the switch to make sure the control room gets an alarm. Not able to calibrate.

Minimizing ammonia-blower failures

3. Additional support was added to fan base



4. A tighter balancing requirement limited the radial loading on the coupling-end bearing

Challenge. The plant is equipped with Robinson SCR blowers that disperse ammonia into the gas-turbine exhaust. The NH_3 works in conjunction with the SCR catalyst to reduce NO_x emissions. The turbines cannot remain in compliance with our operating permit without effective ammonia injection.

Each unit has two blowers with opposing rotation. Because of this design, it became difficult to always have a backup blower in stock, and with frequent failures, excessive downtime became an issue. Before modifications were made on this system, we experienced three to four blower failures per year.

The root cause was bearing failure but other issues became evident such as balancing, lack of support in the blower base, and certain O&M practices. The average annual cost of these failures was approximately $14,000, not including the cost of production downtime.

Solution. The root cause for bearing failures was incorrect bearing application and balancing. The solution was to add more rigidity to the base of the fans. Gusset plates as well as additional steel and concrete were added to the support structure to reduce horizontal movement relative to the base (Fig 3). A floating, expansion-type, heavy-duty bearing replaced the old pillow-block bearings.

The pillow-block bearings were designed to be a light-duty air-handler fan bearing, which was not the correct application. This caused the coupling end to be too lightly loaded, which in turn caused the ball bearings to slide instead of roll. The new bearings also allow for shaft thermal growth.

The next issue tackled was balancing. It was necessary to balance the fan to within a 1W/N standard, which limited radial loading of the coupling-end bearing because of the overhung design. Site personnel installed the new fans to ensure optimum performance (Fig 4).

To reduce downtime caused by bearing failures, the plant now stores two assembled blowers with opposing rotations and runs opposing blowers on each unit, which improves installation time and guarantees a backup blower in stock. We also started greasing these bearings weekly because of the high heat and stress they are exposed to regularly.

Results. The plant has experienced zero downtime because of ammonia-blower bearing failures since implementing maintenance and operational changes. When a blower failure does occur, a lag unit is available and can be installed quickly. All of these changes have reduced annual equipment and labor costs from $14,000 to $3,500.

Project participant: Sean O'Neill

Replacing problematic process sample lines

Challenge. As Effingham ages, it becomes apparent that certain systems just were not cut out for the long haul. The system installed to provide steam and water samples to the sampling building relied on a multi-function tubing that plant staff refers to as "umbilical lines."

The original lines consisted of single or multiple runs of stainless-steel tubing, along with a heat-trace cable spirally wrapped in layers of thin insulation and covered with a hard plastic sheath. There are approximately a dozen lines that run from the top of each HRSG to the sample building. Since the facility is a 2 × 1 combined cycle, two HRSGs feed samples to the water lab.

Over the years, some of the umbilical lines developed problems with either leaking lines that had ruptured or the heat-trace failures (Fig 5). Early on, personnel tried to fix the lines with factory repair kits but found this to be almost impossible. The most difficult part of the repair was being physically able to access the repair point in the lines and then to separate the lines from one another to facilitate the repairs (Fig 6). Staff soon learned that erecting scaffolding to the repair area was almost the only way to access the locations needed; at times, even that was not possible.

The umbilical lines originally were installed from the sample building in cable trays that housed multiple lines. This made separating them for repairs almost impossible, not to mention that where the lines left the pipe rack they turned up the side of the HRSG for

5. Leaking sample lines and heat-tracing failures were relatively common

6. Arrangement of sample lines made access and repairs difficult

7. New system consists of a cable tray with 12 heavy-wall sample tubes

8. Special brackets are designed to accommodate high sample temperatures (left)

9. Tray and tubing were installed from the top of both units to the water lab (right)

approximately 50 ft in an area that was totally inaccessible. This motivated plant personnel to find another way to get the samples from the HRSGs to the sample building.

Not only were the umbilical lines inaccessible, they are very expensive to replace. The average cost of a single line from the farthest unit out was between $3000 and $10,000 depending on the makeup of the line; then there was the challenge of getting into the spaces for replacement.

Solution. After much thought and investigation, staff decided to install a completely independent system for sampling, using an area on the side of the HRSG that was less congested and completely accessible. This made installation possible and allows operators access to the system for repairs.

The new system consists of one 18-in. cable tray with a solid bottom (Fig 7) containing 12 heavy-wall 0.375-in. stainless steel tubes encased in insulation—1.5 in. on the bottom of the tubing, 1 in. on the top. The tubing was installed on brackets with special stainless-steel clamps to accommodate the high-temperature environment (Fig 8).

Two high-temperature heat-trace cables were installed just underneath the tubing brackets to mitigate freezing of the sample lines in cold weather. Forming a pocket with the insulation encasing the tubing, and having heat tracing in the middle, proved a positive method of installation.

The tray and tubing were installed from the top of both units (Fig 9) to the water lab prior to being shut down for a planned outage in order to connect the tubing to the proper locations. During an outage, tubing was connected to the proper locations and put into service.

Results. Prior to the installation of the new sample system plant really had no way to safely and effectively repair the umbilical lines and keep the sample system functional. Without the sample system operating properly it is almost impossible to track needed chemicals and treatments.

With the new installation, operators now have a dependable sample of all needed steam and water to our lab and the system is totally accessible for repairs and maintenance. Had the plant replaced the entire original system, cost would have been about $400,000 per unit; the new system cost less than $200,000 for both units and it now is possible to access the entire system for maintenance.

Project participants: Alan Sparks, Andrew Fenstermaker, Cheryl Hamilton, Chris Hofer

Improved insulation design extends life of GT thermocouples

Challenge. Over the past several years, Effingham experienced an increase in gas-turbine (GT) thermocouple failures. There also was a sharp increase in T/C cable replacements. The cost of replacing these components is high, and because there is no predictive tool to determine their failure rates, staff is unable to properly budget for this added expense.

In 2012 and 2013, 55 failed thermocouples were replaced on the plant's two 7FAs at a total cost of $27,000. During this same period, 17 thermocouple cables were replaced at a total cost of $6600. The time required to change these components was significant—typically one hour per thermocouple change-out and two hours per cable replacement.

Additional costs are incurred if the control room operator (CRO) does not take prompt action when a thermocouple fails and the affected unit trips. During 2012 and 2013 this happened twice. One trip occurred during startup, resulting in additional lost revenue.

When there are forced thermocouples in the Mark VI system, setpoints must be adjusted as load is increased or decreased. Typically this is not an issue when you only have one thermocouple forced; but if there's more than one, the CRO must anticipate these changes in advance. Example: During a shutdown, with two thermocouples forced on one unit, the GT tripped because the CRO did not change setpoints as required. Lost revenue was not an issue in this instance, but there was the possibility of equipment damage.

Solution. The original design had metal covers over the thermocouple terminal blocks to protect them from the environment. These covers were thought to be holding the heat in and causing premature failure of the T/Cs and cables.

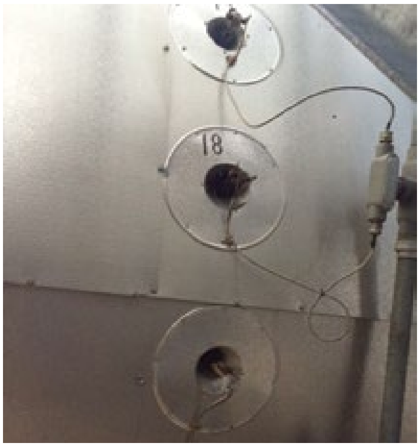
Staff contacted several other plants with 7FAs to determine if the covers were necessary to protect the thermocouples. Response: Their T/Cs were uncovered and the environment had no effect on thermocouple performance. However, after removing the covers at Effingham, the failure rate of the T/Cs and cables did not go down.

The plant continued to investigate the premature failures, which lead to measuring the temperature at the thermocouples with an IR thermometer. It was greater than 700F at the thermocouple terminal blocks with the highest failure rate. This is higher than the maximum design temperatures for both the T/Cs and the cables (500F).

The next corrective action was to add more insulation in the space between the flashing and thermocouple terminal block. Insulation was installed by plant personnel, surrounding the T/Cs with the highest failure rate. The additional insulation did not reduce the failure rate.

The next step was to learn why temperatures were so high at the thermocouples, especially in the lower half of the exhaust casing. But the plant was in the middle of the summer run season and could not shut down to investigate.

The plant continued to review options for correcting high temperatures at the next scheduled outage. One possible solution was to replace the flex seal, thinking possible leak-by. An inspection of the seal's condition was required to determine its condition prior to scheduling a change-out, given the significant cost and time needed to make the repair. Since the seal inspection could not be completed while the unit was operating, the seal replacement option was not considered.



10. New flashing design protects T/Cs and cable against excessive temperatures

During the plant's fall outage, a local contractor removed the existing flashing and insulation from both GTs. It found the insulation around the casing had shifted on both units. The lack of insulation in certain areas minimized protection for a majority of the thermocouples, allowing their exposure to excessive temperatures and causing premature failure of both T/Cs and cables.

After the insulation was removed, plant staff inspected the exhaust casing for cracks. None were found. Also, personnel were able to inspect the flex seal to determine if its immediate replacement was necessary. A few loose backing plates were found and tightened. After minor repairs, the seal was certified fit for duty until a replacement could be scheduled at the next major inspection.

Next, new insulation and flashing were installed on the casing. The flashing was placed over the insulation in accordance with OEM specifications. It was formed into a funnel shape, protecting the thermocouples and cables from excessive temperatures (Fig 10).

Results. The new design protects T/Cs and facilitates maintenance. There is no issue with changing-out thermocouples or cables. Recall that with the original design, covers had to be removed to inspect connections or to change out components. There have been no thermocouple or cable failures since repairs were made in fall 2013. Result: A significant reduction in maintenance costs and an increase in plant reliability.

Project participants: Alan Sparks, Ken Earl, Nick Bohl

Simple fix cures chronic overheating of air compressors

Challenge. Clean, dry, and reliable compressed air is critical for powerplant operations. The plant air compressors are motor-driven. The intercoolers, aftercoolers, and lubricant coolers are integrated into a single radiator that is forced-air-cooled by a fan inside the air-compressor enclosure. The ambient cooling air inlets and outlets are ducted outside the building.

During summer months, compressor oil temperature would run near the maximum allowable, and often trip on high oil temperature. The high oil temperatures also contributed to more frequent failure of the oil pressure regulators and oil-actuated loading valves. Cleaning hatches were installed into the ductwork to help clean the radiators/oil coolers, but oil temperatures continued to run high during hot ambient conditions.

No facility production was lost, but maintenance costs and labor required for frequent cleaning was higher than expected. There was also concern for long-term reliability of the equipment from operating at high temperatures.

Solution. The ambient cooling-air inlet ducts are at chest level and the hot-air outlets are two ft above the inlets on the outside of the air compressor room (Fig 11). An employee was investigating the overheating problem and observed that the inlets and outlets had screened and louvered covers, and that all of the louvers were pointing down.

11. Inlet and outlet air ducts are separated by only 2 ft and the louvers serving the upper hot-air ducts were angled downward, allowing recirculation of hot air to the inlet

Closer inspection revealed that the hot outlet air was directed down, where it was recirculating back into the cooling-air inlet ducts. The employee requested and was given permission to remove and rotate the hot air outlet ducts upward and away from the cooling air inlet ducts.

Results. Flipping the outlet duct louvers directed the hot air upward and away from the air inlets. The modification improved equipment cooling and consistently lowered oil temperatures by approximately 10 deg F. The air compressors have not tripped on high oil temperature since the modifications were completed. Frequency of failure/replacement of oil pressure regulators and loading valves was reduced by more than 50%.

Project participant: Don Johnson

Arc-flash warning strobes

Challenge. When operating 13.8-kV supply breakers, it is not always possible to prevent access to the flash-hazard boundary solely by use of an attendant. Within this boundary it is possible to be exposed to energy levels of 1.2 cal/cm^2 during an arc-flash event, which is sufficient to cause second-degree burns. It is the attendant's responsibility to keep personnel out of the boundary area during breaker operation.

This can be difficult because of switchgear location and the availability of several access routes to the area. Personnel conducting these evolutions perform a pre-job brief and are made aware of all boundary locations and potential hazards.

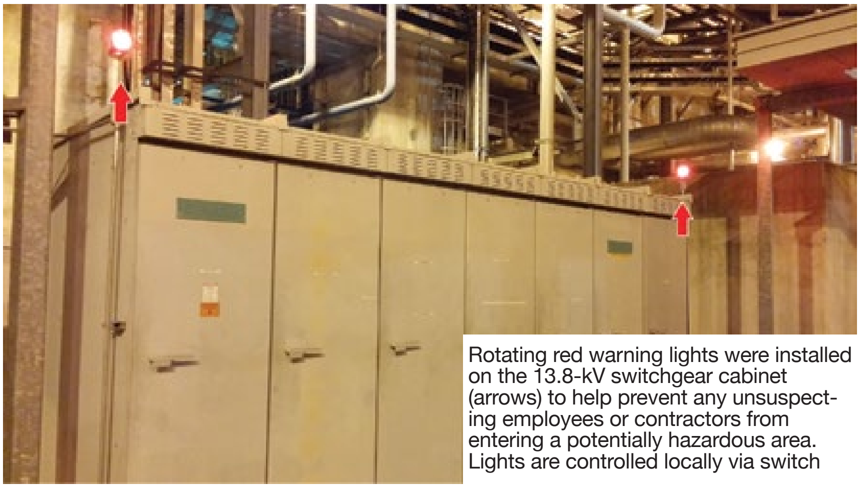
The flash-hazard boundary for the switchgear is 95 ft in all directions. Keeping personnel out of this area is most difficult when contractors are onsite and could enter the hazard boundary without proper warning.

Solution. Several solutions were evaluated to alert personnel of the hazard. One method evaluated was to use "DANGER" tape connected from post to post. It was ruled ineffective based on material and manpower costs for set-up and take-down, given frequent breaker operation.

Posting permanent signs at the hazard boundary distance on commonly used routes was selected based on low cost and ease of use. An additional method to alert personnel was to add rotating red warning lights on the 13.8-kV switchgear cabinet (Fig 12).

Placement of the lights was important: They had to be visible to personnel approaching the switchgear. Plus, plant staff did not want to make any penetrations into the switchgear cabinet that could lead to water ingress.

During a period that the switchgear was de-energized for maintenance, plant's high-voltage contractor was consulted on the proper location for the lights and a power source. An automatic transfer switch and 120-Vac source assure the red warning lights are powered at all times. Established switchgear penetrations were used. A



12. Rotating red lights (arrows) warn when an arc-flash hazard is present

13. Highly visible, durable signage warns of hazardous operations. Arrow points to 13.8-kV switchgear

light switch was placed on the front of the switchgear to energize and de-energize the lights as required.

A local print shop designed and constructed the warning signs posted throughout the plant (Fig 13). Highly visible colors were selected to alert personnel approaching the area that hazardous operations were in progress. Also, these signs were constructed of weather-resistant materials to ensure long-term use and the need to only replace them periodically.

The signs also are used as a location for the attendant to retreat to while the breakers are being operated. This establishes safe work habits and supplements the plant's current arc-flash program by providing a very clear location at which you are safe from an arc flash.

Additionally, flashing red lights aid in alerting approaching personnel of a potential hazard. The light can be seen from areas not covered by the permanent signs. Also, all plant personnel are trained to stay away from any areas when a flashing red light is illuminated. Information concerning arc-flash safety also was added to the plant's contractor safety brief.

Results. The safety measures described help an attendant secure the flash-hazard boundary area around the 13.8-kV switchgear. Also, it alerts personnel in the area that a hazardous operation is in progress.

Personnel not part of the safety brief are alerted when approaching the boundary and know to stay clear until the operation is complete. With these additional methods of boundary control, Effingham minimizes the potential for unprotected personnel entering the hazard boundary.

Project participants: Michael Sears Jr and Sean O'Neill

Fire-protection controller retrofit

Challenge. The controllers for the fire-protection system on both gas turbines had caused three inadvertent releases of carbon dioxide and two trips of Unit 1 at full load. The loss of power generating capability, lack of reliability, danger to personnel, and hazards to equipment were unacceptable. The controllers were obsolete and prone to spurious ground faults that caused unnecessary alarms. This equipment is no longer made by the manufacturer and parts could not be acquired.

Solution. Staff researched a suitable replacement for the Chemetron Micro 1EV controllers. The latest compatible controller is the Chemetron Micro XLT. Effingham GTs have three zones per unit, so six controllers were required. To have a new fire protection system installed by a contractor would cost over $100,000 per unit.

It was decided that the only part of the system that had to be changed was the controller.

Plant acquired the new controllers and wiring diagrams necessary to make the conversion. A bench test verified both the proper circuit-board configuration for Effingham and operation. The upgraded systems were tested and certified by Century Fire. The old controllers were given to another plant.

Results. The new Chemetron Micro XLT controllers are a much needed upgrade. They provide increased reliability to a vital plant system essential to the safety of equipment and personnel.

Project participants: Christopher Hofer and Alan Sparks

GT major maintenance made easier

Challenge. Major maintenance events for gas turbines can range from the small task of replacing a combustion can to conducting a major inspection. Almost every major maintenance activity calls for removal of the turbine-enclosure roof.

At Effingham, this required disconnecting six motors along with their associated heater circuits and switches, and removing all instrumentation—transmitters, low-voltage switches, and sensors.

Plus, wiring had to be removed from conduits and fittings which traverse the roof top from the cable trays located along the sides of the enclosure. Wiring typically runs 30-40 ft from the cable tray to each device.

Removing wiring from all devices is very time-consuming and subjects the cables to stress and possible damage. It typically took four technicians approximately 12 hours to prep the roof, costing about $2000; more if cables were damaged and had to be replaced. In addition, one or more contractors likely were standing around waiting on the electrical prep for roof removal—often at significant additional cost.

Solution. To minimize the time and cost associated with removal of roof sections, the plant added two junction boxes at the edge of the roof sections right above the cable trays that supply the cables to the roof-top conduits. Junction boxes were fitted with 3-phase distribution blocks for motor conductors and terminal blocks for the smaller power and control wiring (Fig 14).

The junction boxes stay in place on the roof top when it is being removed, allowing all of the cables and connections to remain intact. Cables coming into the junction box from the cable trays are removed from the junction-box terminal blocks and pulled the 3 ft from the junction box back into the cable tray for removal of roof sections, improving the reliability of power and control circuits.

Results. Installation of junction boxes provided the following positive results:

- The amount of time and labor required to remove and install the roof sections has been reduced. Prior to making the modifications described above, roof removal with a contractor waiting could cost approximately $10,000. Today it costs less than $500 of technician time to unwire the roof sections.
- Turbine reliability has been improved by not having to remove the wiring and risk cable damage. Not having to replace motor conductor connectors and insulation, and the associated hardware necessary to complete the installation, is a cost saving.
- Junction-box installation also reduced the risk for something to be terminated incorrectly as the terminal blocks and cables are all plainly numbered and marked for easy installation when reinstalling the roof sections.

Project participants: Alan Sparks and Cheryl Hamilton

14. Junction boxes reduce the likelihood of incorrect field terminations

Reducing station service load increases revenue

Challenge. Operation of equipment when unnecessary increases station service load. The facility's cost for electricity is $0.05/kWh; the plant produces power for $0.025/kWh. Thus, when Effingham does not have a GT in operation, the cost of station service is doubled. Cycling facilities have BOP equipment that must be started before the GTs are online. At Effingham, this includes 2500-hp boiler-feed pumps, 1500-hp circ-water pumps, and other auxiliary equipment totaling more than 500 hp.

Solution. During plant startup, when condenser cooling requirements are minimal, Effingham operates with only one circ-water pump; the BFPs are not started until necessary. During shutdowns, one circ-water pump and the BFPs are removed from service as soon as they are not needed.

- Startup: Steam seals for the steam turbine are placed in service 10 minutes after the circ-water system, which provides the necessary condenser cooling. Two 1500-hp pumps are required when the plant is at full load; however, it takes the plant 105 minutes to ramp to rated output. One circ-water pump provides sufficient cooling when only admitting seal steam and when plant output is less than 250 MW.
- Shutdown: GTs ramp down from 502 MW and are offline about 12 minutes after a stop is initiated. As noted above, only one circ-water pump is needed on startup until plant output reaches 250 MW; the reverse is true for shutdown, but the cost impact is greater because the GTs are offline. Thus, one circ-water pump is stopped when breakers are opened. A normal shutdown is complete 35 min later. If one pump was not removed from service, it would have operated unnecessarily for that period of time.

Results. This simple change in operating procedure produced an immediate cost saving and is accretive to the bottom line.

Project participant: Bill Beahm

Tube sampling, proper drain system contribute to long-term reliability

Knowing how to locate and sample boiler tubes that leak or fail, to enable a proper root-cause analysis (RCA), is critical to the long-term reliability of your heat-recovery steam generator (HRSG). Periodic tube sampling also is highly recommended by the industry's top chemists and metallurgists, as a preventive measure, to identify early on if damage mechanisms are at work on the steam/water side of your units. These experts can help select the sample locations and perform the analyses to assure meaningful results.

Tube sampling was the focus of one presentation, by Craig Dube, at HRST Inc's "F-Class HRSG Spotlight Session" at the 24th annual meeting of the 7F Users Group at the Sheraton Downtown (Denver) in mid-May. He began by answering this question: "Why sample when you find a tube leak and not just weld over the leak?"

The answer: A meaningful RCA is not possible without examining the inside surface of the tube. Some of the first things to determine, Dube continued, are the following:

- Did the failure initiate from inside or outside the tube?
- Is cracking in evidence? If you find cracking, what is the shape of the cracks? Are the cracks in or near a weld? Do the cracks follow the grain boundaries or do they cross them?
- Is pitting involved?
- Regarding the condition of the tube internal surface, is scale present? If bare metal, is it polished?

The speaker said owner/operators will get best results from an investigation that provides both a *macro view* of the failure location, by a boiler engineer, and a *micro view* of the damage, by a metallurgist. It's important, he added, to carefully document the failure (sample) location. Using an economizer panel as an example, Dube asked:

- Is the location of the distress at a tube-to-header joint? Might thermal shock be involved? Corrosion fatigue?
- For a multi-pass economizer, is the failure near a splitter plate? Again, might thermal shock be involved? What about buoyancy instability?
- If the failure is in the middle of a panel, is the affected tube up-flow or down-flow?

For an evaporator panel, is the failure near a feeder, near sidewalls, near coil-to-coil baffles? Is high-velocity wear in evidence? Is heat flux higher than the design value?

For superheaters and reheaters, is the failure downstream of an attemperator? If so, is there overspray or leak-by? If the damage is at the lower header and near the ends of the panels, might undrained condensate be involved? Is the damage directly across from header nozzles?

To be sure there's no misinterpretation of field findings, it might be in your best interest to retrieve a drawing of the panel and show exactly where the damage was found. Also provide design data if available, and any relevant operating information from the plant historian.

Case study. Dube next ran through several tube-leak case histories. Perhaps the case of greatest interest to this F-class audience, and the one best illustrating the need to follow *all* the evidence to assure a proper conclusion, was one involving a panelized feedwater heater that had experienced many tube failures.

HRST performed the failure analysis for the plant owner, using both macro and micro assessments of the damage. A tube sample and failure sample photos were received by HRST from its customer to initiate work. Plant personnel had kept meticulous records and reported the following stats and observations:

- There were 40 failures in up-flow passes, 117 in down-flow passes.
- Buoyancy instability was considered the most likely cause of the down-flow failures. Note that down-flow tubes absorb more heat and are more susceptible than up-flow tubes to buoyancy instability.

Here's the mixed-bag of evidence the HRST sleuths had:

- Photos of the sample site revealed internal corrosion with crack-like indications.
- Lab analysis of the sample received showed pitting, but no cracks.

They concluded, based on a macro view of failure locations and micro view from photos and sample lab analysis, the most likely cause of failure is a combination of the following:

- Axial stress caused by flow instability in down-flow tubes.
- Pass-to-pass stress caused by temperature differences between up-flow and down-flow sections.
- Internal corrosion of tubes.

Investigators agreed that (1) not having an accurate sample location could have led to a misleading conclusion, (2) care must be taken to avoid attributing failures to pitting only, and (3) repairs to the tube failure area should involve redesign of economizer up-flow and down-flow characteristics.

Another case study began with the finding of "raccoon tails" in the LP economizer. Non-destructive examination (NDE) of the tube in place revealed crack indications, and a tube sample was removed. Lab analysis identified microscopic intergranular cracks, highly branched within a narrow band, which is indicative of stress-corrosion cracking. With this information, HRST engineers concluded weld repair of the cracks would be unreliable and that an upgraded material should be specified for replacement tubes.

Sampling of HP evaporator tubes was the next topic covered by Dube. He told attendees these tubes can be damaged beyond repair from waterside deposits. Under-deposit corrosion and overheating are the primary damage mechanisms of concern, Dube said.

He cautioned users responsible for HRSGs operating more than 10 years without having had a representative HP-evap tube sample analyzed by a qualified metallurgist that they were taking an unnecessary risk. Deposits form slowly, he reminded, and you can have no problems for years. But if a water-chemistry upset were to occur you could have big trouble quickly.

The speaker continued, providing a backgrounder on the following forms of under-deposit corrosion:

- Hydrogen embrittlement typically occurs at operating pressures above 1500 psig when the system is subjected to a low-pH excursion. Deposits exacerbate the damage mechanism because hydrogen concentrates under the deposit. This condition can occur in only a few hours.

- When used for pH control, caustic can concentrate on the tube-side of deposits and attack the base material. Thinning of the tube wall is a result.
- If a blended phosphate is part of your plant's water-chemistry regime, and an upset occurs, attack by hydrochloric or sulfuric acid can occur under a deposit. Local tube-wall thinning is a result.

Dube said HP evaporator tubes in the highest-risk group are in F-class HRSGs where duct burners often are used and there's a history of flow-accelerated corrosion (FAC), and/or water-quality issues, or a borescope inspection reveals waterside tube-wall deposits of concern. He suggested the following three-step process to assure proper sampling:

1. Perform a heat-flux analysis of the evaporator to help identify areas at highest risk.
2. Borescope the high-risk zones. This is not as easy as it might sound. Before moving forward, it's important to carefully select entry points to the waterside, specify the hardware and mechanical team required to gain access as well as the borescope best suited for the task, and then finalize work plan and procedures with the borescope technicians assigned to your job.
3. Use borescope results to influence the urgency of sampling and where to cut out the samples. Don't forget gathering the macro information before sending the samples to the lab for metallurgical analysis.

Two additional points made by the speaker:

- Be sure you have the proper tube material on hand to replace the section removed for the sample.
- In some cases, tubes will fail at locations virtually impossible to reach and tube plugging is the practical solution. Happens. Problem, of course is that there's no sample to analyze to determine the failure mechanism. If you go this route, highly experienced crafts persons are recommended.

Drains

You're likely to hear about drain issues at virtually every industry meeting addressing the information needs of HRSG users. Hard to believe, but despite years of industry discussion, equipment specifiers responsible to plant owners and EPC contractors, and the manufacturers of heat-recovery steam generators, often fail to deliver drain systems that meet the expectations of operating personnel.

So it was no surprise that "HRSG Drains" was one of the presentations in the HRST session. Jonathan Aurand, considered by some one of the industry's young stars, was the presenter and discussion leader.

He said drain issues are most prevalent in the superheater (SH) and reheater (RH) sections—particularly when HRSGs are in cycling service. Also, that each OEM and each design has unique challenges. Resolving persistent drain issues, Aurand continued, often requires a comprehensive understanding of how the system was intended to work, in addition to identification of specific shortfalls. He would not have been a good soldier for the house that Bob Krowech built had he not added "third-party support is often beneficial, specifically for merchant plants without a lot of overhead staff."

Aurand focused his presentation on the following SH/RH drain issues:

1. Drains undersized and/or in need of automation.
2. Low point in the piping system undrained.
3. Low point in the piping system not drained consistently.
4. Drain movement. Differential expansion amplifies drain lateral displacement and the penetration seal and the hole in the casing must allow for a full range of motion.
5. Drain bending (expansion overstress).
6. Bypass of saturated or cooler steam.

Some tips Aurand shared with attendees included these:

- Properly executed, spring supports can reduce thermal stress on tubes and jumper pipes while also correcting drain movements.
- Ensure lower headers have bumpers and permit little or no lateral movement.
- Reconfigure drains to allow greater flexibility before piping passes through the casing.

The speaker said, based on HRST's surveys of drain systems over the years, here's how the company's engineers rank the causes of ineffective draining:

- Drains on HP, SH, and RH tube panels of 1 in. diam or smaller for F-class and larger gas turbines.
- Primary drain valves are not equipped with actuators (manual valves only).
- Primary drain valves have actuators (pneumatic or motorized), but no water or condensate detection for control.
- Drains are automated with TE condensate detection, but plant operations has no provision for automatically draining the system in a cold start.
- Operators have a false sense of security when drain valves are in "auto."

Here's what HRSG recommends improve under-performing drain systems:

- Use drain lines 1½ in. or larger in the HP, SH, and RH sections.
- Automate drains to the greatest extent possible, preferably using ¼-turn ball valves and pneumatic operators. Without automation, Aurand said, operators will forget to open/close drains given all the activity during startup and today's reduced staffing. If you have an actuator, he continued, there must be a timer integrated into the control system to open the valve.

  Note that the timing is different for cold, warm, and hot starts. The speaker metioned that one plant he knew of failed to investigate open/close in logic only to learn later that the drain valves closed on 25 psig during a warm start. . .but there was no logic to open them. Resulting tube failures were thought the outcome of never having properly drained the headers.
- Condensate detection system must work within site constraints and owner preference for conductivity switches, level transmitter, TE activation, or a newer scheme being developed by HRST using level-transmitter methodology. CCJ

Varnish issues addressed by several user groups last spring

Proper care of your turbine's lube oil is critical to reliable operation. A significant contributor to unavailability, especially at plants powered by gas turbines relying on mineral-oil lubricants, is varnish, which can impede operation of servos in control systems, plate out on bearing journal surfaces and increase the severity of vibration, etc. Varnish formation is impacted by lubricant chemistry (QR 1), the additive package, temperature, and other factors—some under your direct control, others not so much (QR 2).

Perhaps the most practical and cost-effective way to mitigate the adverse impacts of varnish in any given steam- or gas-turbine lube-oil system is to continually remove it from the circulating fluid. There are several commercial solutions capable of doing this, some better than the others under certain operating conditions.

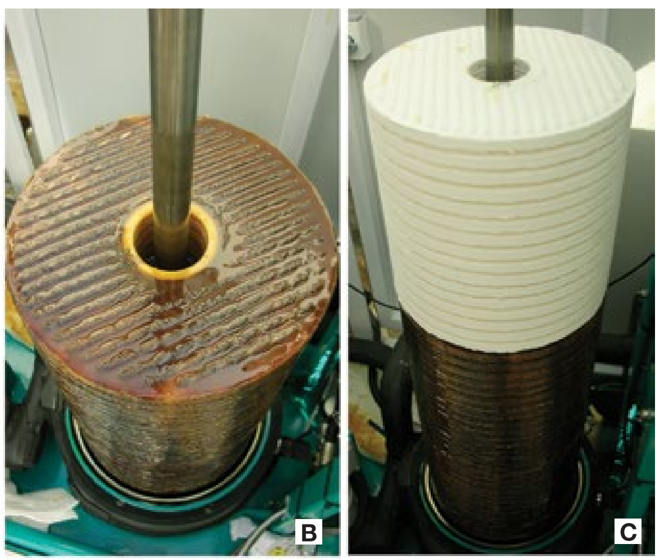
One way to identify the solutions providers is to use CCJ's online buyers guide (QR 3), another is to type an appropriate keyword into the search-function box on CCJ ONline's homepage (QR 4). If you want to "kick the tires," attend one of the upcoming user-group meetings—such as the 7EA Users Group (QR 5)—and walk the vendor fair.

QR 1 QR 2 QR 3 QR 4 QR 5

QR 6 QR 7 QR 8

That varnish is a significant concern in the user community was in evidence at the 501F/501G and 501D5-D5A meetings in spring 2015 with C C Jensen Inc's (QR 6) Technical Manager, Axel Wegner, invited to address owner/operators at both conferences. The two presentations were much the same; however, a D5 user joined Wegner at the podium for the second meeting to validate results.

Wegner began both presentations with a review of a typical oil analysis incorporating data from RPVOT, FTIR, acid number, Ruler, Karl Fisher, and other tests. This material has been discussed by many presenters at user-group meetings over the years and is familiar, if not well understood, by most owner/operators with supervisory



1. Varnish removal unit sits on skid awaiting installation to serve a 501D5 (photo A). The VRU removes both dissolved and suspended soft contaminants from turbine oil. Cellulose-based varnish removal inserts, stacked inside the filter house, remove varnish and when saturated (B) are replaced with new inserts (C) positions on the deck plates.

Those who benefitted most from this segment of the presentation were first-timers and those new to the industry—typically about a third to half of the attendees. Access "Analysis and maintenance of turbine lubricants" for a quick review of information you should be aware of (QR 7).

Regarding the presence of varnish in lube oil, Wegner said the most meaningful results for the majority of users are obtained from the Membrane Patch Colorimetry, or MPC, test, which recently was approved by ASTM (American Society for Testing and Materials). The value of ASTM certification is a well-defined and repeatable test process with results from different labs comparable. The test involves making a patch that isolates and agglomerates insoluble byproducts associated with varnish. The color of the patch provides a guideline as to the extent of varnish potential (QR 8).

Wegner's personal favorite is the UC test, because you can see varnish in the oil that could plate out in a turbine system. When relying on ultra-centrifuge test data, keep in mind that any result above "1"—the lowest value on the 1-8 scale—is unacceptable.

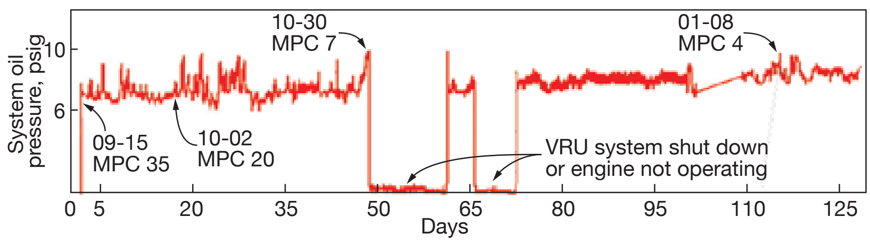
The next segment of Wegner's presentation focused on choosing the proper oil conditioner for a riven application. He told the users, "Today we know the following three methods for removing varnish":

- Physical filtration, including absorption and adsorption, removes only insoluble varnish. You can select from depth or surface filters, he said, with or without preconditioning step—such as electrostatic, balanced charge agglomeration, etc.
- Chemical filtration removes both soluble and insoluble varnish. In use are cartridges with chemical bead compositions of different mixtures which can be adjusted to optimize performance for a specific oil and engine. This solution can be pricy. A disadvantage of it is there's no increase in pressure drop to indicate varnish saturation: You have to carefully monitor MPC results to know when the beads are "full" and must be replaced.
- Depth-filter absorption/adsorption with advanced agglomeration removes both soluble and insoluble varnish. This is the C C Jensen solution—VRU, for varnish removal unit (Fig 1A)—which Wegner said effectively preconditions the oil in a manner that soft contaminants fall out of solution (without chemical aids), agglomerate, and are removed by depth filter inserts with high dirt holding capacity (Fig 1B). The VRU removes particulate matter, varnish, and water from the oil. This was said to be the only method where high pressure drop indicates varnish saturation and when the filter inserts must be replaced (Fig 1C).

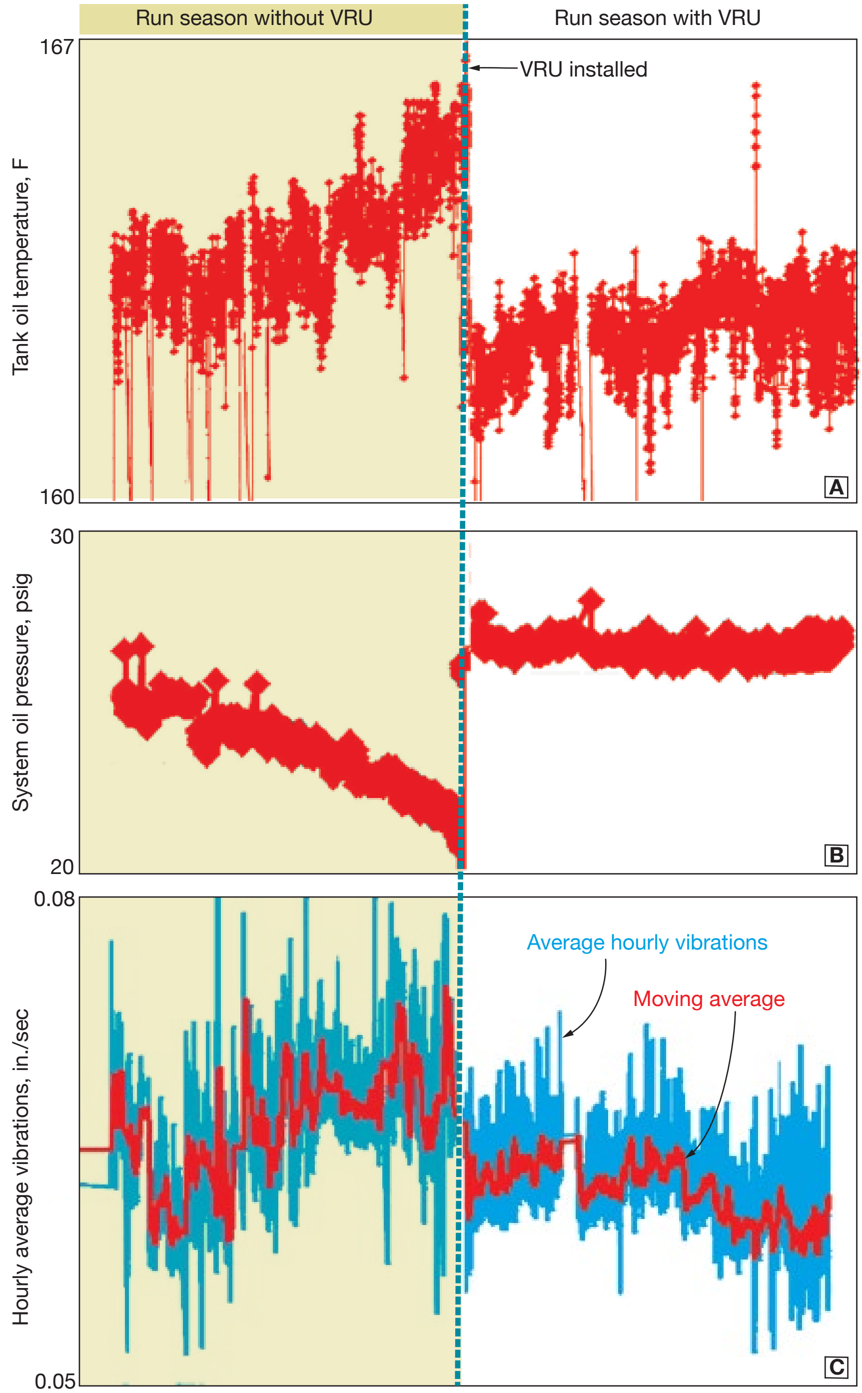
The obvious question from a user: Which method should I choose? Wegner said, "That entirely depends on the efficiencies of alternative systems in your specific application." He offered these general criteria:

- Systems with oil operating temperatures up to about 100F can be treated by any one of the three options identified above.
- In systems where lube-oil temperatures alternate from less than about 100F to more than 100F (such as daily-start engines), all three options generally work as well. However, the physical filtration method might prove less effective at higher temperatures unless the filter medium is upgraded, because more varnish will be in solution.
- When lube oil is constantly over 100F, physical filtration is not viewed as an effective option for varnish removal, according to C C Jensen's technical expert. Some of the chemical solutions also may be temperature-limited, he said, although most can handle up to 160F. The VRU was said to not be limited by even the highest oil temperatures generally encountered in powerplant service.

Wegner's next topic: Methods to validate the effectiveness of an oil conditioning system. He offered the following:



2. A 501D5 user presented operating data that showed the VRU reduced MPC from 35 to 4 over about a three-month period. A single set of cellulose-based inserts cleaned up the oil without causing a drop in the nominal average system operating pressure because of its considerable varnish holding capability



3. Operating data validate VRU performance. Tank oil temperature (graph A at top), system oil pressure (B), and vibration (C) data show improvement after varnish was removed. Regarding the last, the average vibrations during the run season with the VRU were 7% below that for the previous run season without the VRU

- Oil analysis. The VRU's 90+% single-pass efficiency is best among the alternatives, Wegner said, and offers a foolproof method for evaluating system performance right out of the box; chemical filtration generally ranges between 10% and 50% single-pass efficiency, while the range of numbers for physical filtration are lower. Trending of MPC levels in the turbine sump over time is another way to chart progress. Wegner recommended sampling the sump every two weeks until varnish is reduced to an acceptable level (less than MPC of 5). He added that the VRU typically halves the MPC value every two weeks until it drops to 5 or less (Fig 2).
- Filter inspection is simple. Just visually check used filter inserts for varnish accumulation.
- Visually inspect turbine components—such as servos, bearing journals, thrust-bearing shoes, etc—for varnish deposits.
- Compare key performance indicators over time, including the following:
  1. Sump oil temperature. Lube-oil coolers are more effective without an insulating layer of varnish.
  2. System oil pressure. Deposits can impede the delivery of oil to bearings, possibly reducing system pressure to less than that required for optimal lubrication.
  3. Vibration can increase because of varnish deposits on journal surfaces.

Fig 3 shows the positive impact of varnish removal graphically.

Varnish a hot topic at CTOTF as well

Attendees at CTOTF's Spring 2015 Conference and Trade Show heard from other lubricant experts—users and suppliers—during both presentations and open discussion forums, on how to prevent varnish formation and how to eliminate it from systems susceptible to varnish formation.

During the GE E/EA-class session, an OEM lube-oil presentation generated questions and discussion on industry experience with TF-25, a synthetic polyalkylene glycol (PAG) substitute for conventional turbine oils that does not produce varnish. The fluid is distributed in North America by American Chemical Technologies Inc (ACT).

At the GE F-class session, Dan McCormick of McCormick & Munson Technologies LLC presented on the identification and removal of varnish precursors as a way to avoid varnish problems associated with petroleum oils.

Just before the CTOTF meeting, Analysts Inc, one of the industry's leading providers of lubricant analysis and testing solutions, released version 2.0 of its Lube Oil Analysis Management System (LOAMS) software, giving owner/operators the capability to compare and trend lube-oil lab results using plant historical information as well as fleet-wide data.

PAG. The OEM presenter on lubricants mentioned that GE now accepts PAG fluids as an alternative lube for its turbines but he had no first-hand experience to answer some of the questions that attendees asked. One of the first questions had to do with the number of turbines currently operating with ACT's PAG products. ACT's Jim Kovanda told the editors the total now is over 100.

There were several other questions related to the experiences of turbine owners with EcoSafe TF-25, and on the function and use of ACT's Ultra-

QR 9

Klean TO and EcoSafe Revive products, which went unanswered for the most part. Much of this information is readily available in the article, "PAG acceptance grows with field experience," available at CCJ ONline (QR 9). However, the questions indicated there may be some confusion among users between UltraKlean and Revive. Hopefully, the following passage clears that up:

ACT originally developed UltraKlean for the purpose of cleaning and preparing a turbine lube-oil system for conversion to TF-25. UltraKlean was designed for short-term use to allow for the circulation of approximately 10% of the cleaner into a varnished turbine-oil system to cleanse all surfaces and components that the comingled fluid would contact. Because the UltraKlean product lacks an anti-oxidant package to provide longevity, the recommendation for circulation to accomplish the objectives was 60 to 120 days.

The Revive base-oil modifier was formulated and patented for use in a varnished turbine oil to shift the polarity of the base stock, cleanse the system (much the same way as UltraKlean), and solubilize varnish. Revive is a more robust treatment than UltraKlean was and it provides a long-term solution for users concerned about high MPCs and visual varnish on last-chance filters.

Key to its effective use is identification of the proper percentage of Revive necessary to shift the polarity. Note that as the fluid continues to cleanse and solubilize the oxidized solid deposits, an additional small percentage of Revive might be necessary to prolong the solution's effectiveness.

A challenge occurred when users were forced to continue the use of UltraKlean beyond the recommended 120-day limit—as happened when an outage was postponed. ACT's response was to discontinue the manufacture and sale of UltraKlean. Users who want to proactively cleanse and prepare a system prior to conversion to TF-25 can use Revive to accomplish the same task. It has been recommended in concentrations from 2% to 20% depending on turbine-oil condition. The PAG base stocks are identical between both products, allowing for similar cleaning while giving the user flexibility to accommodate shifts in scheduling.

Nano-particle tracking and analysis. The thrust of McCormick's presentation was that sludge and varnish precursors and components exist in the sub-micron range before and during all varnishing events. He discussed a new particle counting and sizing technique and the effectiveness of a new electronic nano-filtration system for removing many of the precursors and components in the range of 40 to 1500 nanometers.

Regarding LOAMS 2.0, Analysts GM Cary Forgeron told the editors that his company's new product "gives users more control over sample information and opens the lines of communication between management and maintenance personnel and the laboratory." The software supports a plant-level lubricant wellness program by enabling visual presentation of lab reports and providing the ability to "mine" plant and fleet historical data and trend same.

The expectation is that LOAMS 2.0 will help O&M personnel get to the root cause of problems—such as varnishing. To illustrate, say your company has 10 7FAs at five plants. The new software enables you overlay lab data from each of those units and compare varnish results. If the oil for one of your engines has much higher varnish numbers than the units in the fleet, the next step might be to see if your oil is different from the others. If not, perhaps it's the age of the oil, or duty cycle. Or perhaps the filtration system you have is not effective for removing varnish. It's difficult to do this type of analysis efficiently and effectively without software designed for the purpose. CCJ

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Global leader in the field of air filtration, meeting the most demanding conditions and the toughest environmental challenges. The company's filtration, noise abatement, and other turbine products are effective, durable, and crucial to greater efficiency and performance.

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AGTSI offers a full range of aeroderivative gas-turbine, off-engine, and package parts from the most basic to the most critical. An expansive inventory of spares and replacement parts is maintained at our warehouse for all models of GE LM2500, LM5000, LM6000, and LMS100, as well as P&W GG4/FT4.

AGTServices

Over 200 years of combined, proven OEM engineering, design, and hands-on experience; known in the industry for its schedule-conscious, cost-effective solutions with respect to generator testing and repairs.

Allied Power Group

Earned a reputation for high-quality repairs of IGT and steam turbine components. APG specializes in hot-gas-path and combustion components from GE, Siemens/Westinghouse, and other leading OEMs. Shop staff includes engineers and expert technicians who work together to determine the best method of repair.

American Chemical Technologies

Provides state-of-the-art synthetic lubricants to the power generation industry. Founded more than 30 years ago in the US, ACT has grown to become an international supplier of value-added lubricants that provide superior benefits to equipment, the environment, and are worker-friendly.

AmertechTowerServices

Single source supplier of cooling towers, cooling tower spare parts, repair, and maintenance services; offering competitive prices with expert technicians to oversee the installation, restoration, and preservation of your towers.

ARNOLD Group

With more than 550 installed insulation systems on heavy-duty gas and steam turbines, company is the global leader in designing, manufacturing, and installing the most efficient and reliable single-layer turbine insulation systems.

BASF Corp

Committed to providing customers with cost-effective solutions to the most complex emissions control problems; company is constantly developing new catalyst technologies to meet ever-more stringent emissions requirements.

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Braden Manufacturing

Braden designs and manufacturers air filtration systems and filters, inlet cooling/heating, silencing, exhaust and inlet ductwork, diverter dampers, simple cycle SCRs, expansion joints, bypass stacks, and diffusers and plenums.

Bremco

Full-service industrial maintenance contractor since 1976. Company experience in combined-cycle projects includes header, tube, and complete panel/harp replacements. We also have significant experience in liner repairs/upgrades, duct-burner repairs, penetration seals, and stack-damper installations.

C C Jensen Oil Maintenance

Manufactures CJC™ kidney-loop fine filters and filter separators for the conditioning of lube oil, hydraulic oil, and control fluids. Our extensive know-how ensures optimal maintenance of oil systems and equipment reliability.

Caldwell Energy

Power augmentation, including inlet fogging and wet compression solutions, boosts the output and efficiency of gas turbines. With more than 400k hours of operating experience in power generation, these systems offer proven performance and are backed by a three-year warranty.

Camfil Farr Power Systems

A world leader in the development, manufacture, and supply of clean air and noise reducing systems for gas turbines. A correctly designed system minimizes engine degradation, leading to lower operating costs, optimum efficiency, and less environmental impact.

Chanute Manufacturing

Contract fabricator of HRSG products—including finned tubes, pressure-part modules, headers, ducting, casing, and steam drums.

CLARCOR Industrial Air

Formerly GE Power & Water's Air Filtration business, CLARCOR helps customers achieve air quality and plant performance goals with products and solutions for gas turbine inlet filtration, industrial filtration, and membrane technologies. Company is committed to improving plant performance and enabling users to realize their operating goals.

Cleaver-Brooks

Complete boiler-room solutions provider that helps businesses run better every day. It develops hot-water and steam generation products aimed at integrating and optimizing the total boiler, burner, controls system to maximize energy efficiency and reliability while minimizing emissions.

CMI Energy

Known globally for HRSGs and aftermarket solutions that are engineered to tackle the most stringent power industry demands, company serves its customers with experienced teams, advanced designs, and reliable operation. Count on CMI for proven technologies, expert project execution, and top-quality support for the life of every job.

Conval

Designs and manufactures high-performance valves for the world's most demanding applications, including power generation. Company has a series of power generation case studies that demonstrate the unique features and benefits of forged valves.

Cormetech

The world's leading developer, manufacturer, and supplier of catalysts for selective catalytic reduction (SCR) systems to control emissions of nitrogen oxides from stationary sources. Cormetech SCR catalysts are highly efficient and cost-effective where systems must be capable of reducing NO_x by more than 90%.

COVERFLEX Manufacturing

Offers superior removable insulation systems for an array of gas and steam turbines. Based on OEM turbine designs and feedback from plant managers, insulation systems are custom-designed to provide comprehensive thermal protection.

Creative Power Solutions

CPS is a group of engineering companies in the power generation and energy utilization sector. Its mission is to provide advanced, efficient, and customized technology solutions to clients ranging from OEMs to plant operators and energy consumers.

CSE Engineering

Specializes in gas, steam, and hydro turbine control system upgrades, <ITC>® HMI replacement for GE Speedtronic™ MK IV and V, gas and steam turbine field services, Woodward parts and repairs. CSE is a *Woodward Recognized Turbine Retrofit Partner.*

Cust-O-Fab Specialty Services

Provides the latest technology in exhaust plenums, exhaust ductwork, and exhaust interior liner upgrades that will drastically reduce external heat transfer, making the unit safer and more efficient and easier to operate and maintain.

Cutsforth

Our experience and innovative designs have brought best-in-class brush holders, collector rings, shaft grounding, and onsite field services for generators and exciters to some of the world's largest power companies.

DEKOMTE de Temple

Manufactures fabric and metal expansion joints which compensate for changes in length caused by changes in ductwork temperature. Axial, lateral, or angular movements can be compensated for. Company has gained a global reputation for ingenuity of design and quality of products.

Donaldson Company

Leading worldwide provider of filtration systems that improve people's lives, enhance equipment performance, and protect the environment. Donaldson is committed to satisfying customer needs for filtration solutions through innovative research and development, application expertise, and global presence.

Dry Ice Blasting of Atlanta

Offers professional dry-ice contract cleaning services performed at your facility. Company provides a full range of dry ice blasting machines and capabilities to accommodate any size job by its team of trained, certified, and experienced operators.

EagleBurgmann Expansion Joint Solutions

Leading global organization in the development of expansion-joint technology; working to meet the challenges of today's ever-changing environmental, quality, and productivity demands. Company's flexible products are installed on equipment where reliability and safety are key factors for operating success.

ECT

Offers R-MC and PowerBack gas turbine and compressor cleaners to eliminate compressor fouling. Additionally, ECT designs specialty nozzle assemblies and custom pump skids for the proper injection of chemicals and water for cleaning, power augmentation, and fogging.

Emerson Process Management

Ovation™ control system offers fully coordinated boiler and turbine control, integrated generator exciter control, automated startup and shutdown sequencing, fault tolerance for failsafe operation, extensive cyber security features, and embedded advanced control applications that can dramatically improve plant reliability and efficiency.

ep3 LLC

Brings 25 years of organizational intelligence and software expertise to the toughest challenges of plant operations. Quad C® is an advanced software platform for optimizing plant pre-commercial and acquisitions, maintenance and engineering, asset management, and operations.

FIND A VENDOR, FIX A PLANT

Eta Technologies

Consulting services for all types of GTs, especially in the areas of component manufacture, repair, RCA, component remaining life assessment and metallurgical evaluations, with extensive and unique experience on Siemens V engines. Eta also provides replacement aftermarket parts for V engines.

EthosEnergy

This JV between Wood Group and Siemens is a leading independent service provider of rotating equipment services and solutions. Globally, these services include EPC; facility O&M; design, manufacture, and application of engineered components, upgrades, and re-rates; repair, overhaul, and optimization of gas and steam turbines, generators, pumps, compressors, and other high-speed rotating equipment.

Falcon Crest Aviation

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.

Frenzelit North America

Specializes in providing long-term expansion-joint solutions for gas-turbine exhaust applications. In addition to manufacturing superior quality expansion joints, Frenzelit also makes HRSG penetration seals, insulating materials, and acoustic pillows for silencers.

Fulmer Company

Provider of brush holders, machined components, and assemblies for the OEM, power-generation, and industrial markets. Fulmer is the largest North American manufacturer of brush-holder assemblies, offering single- and multiple-brush units for power generation OEMs and aftermarket customers.

Gas Turbine Controls

World's largest stock of GE Speedtronic circuit boards and components for the OEM's gas and steam turbines. GTC stocks thousands of genuine GE-manufactured cards for the MKI, MKII, MKIII, MKIV, MKV, MKVI, and LCI controls, as well as EX2000, Alterrex and Generrex excitation.

Gas Turbine Efficiency

Provides solutions involving the application of electrical, mechanical, and process-related equipment and components for optimizing system performance. GTE's experienced team of engineers and designers has solid industrial process backgrounds with expertise in fluid systems, instrumentation, and system controls.

GEA Heat Exchangers

From design to construction, replacement towers to spare parts, GEA has built, repaired, replaced and upgraded field-erected cooling towers for over 40 years for the power and process industries.

Graver Technologies

Designs, develops and manufactures a variety of technologies and products that enable and enhance the separation and removal of trace contaminants. Strengths include, but are not limited to, both ion exchange and filtration for condensate polishing and other power generation applications.

Groome Industrial Service Group

Offers a variety of SCR and CO catalyst cleaning and maintenance services nationwide and has formed strategic alliances with industry experts and catalyst manufacturers to ensure that Groome offers the most widely supported, comprehensive, turnkey service available.

GTC Services

Field engineering company offers gas-turbine owners and operators worldwide "Total Speedtronic Support." Engineers have decades of experience servicing and troubleshooting all GE Speedtronic systems.

Gulf Coast Filters & Supply

Keep your filter house and evap coolers operating at peak condition. GCF provides comprehensive, personalized filter-house products, field service, and maintenance, emphasizing safety, professionalism, efficiency, minimal job-site disruption, quality products, and thorough testing and inspections.

Haldor Topsoe

Our air pollution technology includes a series of unique catalysts for Selective Catalytic Reduction (SCR) systems for the control of nitrogen oxides (NO_x), and the reduction of carbon monoxide (CO) and volatile organic compounds (VOCs), from stationary and mobile sources.

Hilliard

The HILCO® Division cost-effectively brings fluid-contamination problems under control and engineers a full-range of filters, cartridges, vessels, vent mist eliminators, transfer valves, reclaimers, coolant recyclers and systems, and membrane filtration systems.

HPI

A leading provider of OEM alternatives for engineered turbine solutions. Founded in 2002, the company offers EPC services for turnkey powerplants; maintenance, repair, overhaul, and mechanical field services in addition to custom controls. Company also is a qualified provider of turbine refurbishment solutions for the nuclear and marine markets.

Hydro

Engineered solutions enable combined-cycle plants to achieve pump reliability and reduced O&M costs. As the largest independent pump rebuilder, Hydro works hand-in-hand with pump users to optimize the performance and reliability of their pumping systems.

Hy-Pro Filtration

Provides innovative products, support, and solutions to solve hydraulic, lubrication, and diesel contamination problems. Company's global distribution and technical-support networks enable customers to get the most out of their diesel, hydraulic, and lube-oil assets. ISO 9001 certified.

HYTORC Industrial Bolting Systems

Takes gas turbine, steam turbine, and HRSG assembly and disassembly to the next level with tremendous improvements in safety, speed, and accuracy on all bolting jobs. From boiler feed pumps and control valves to the entire turbine casing bolting, HYTORC has the tools and fasteners to make sure the job is done right the first time.

Indeck Keystone Energy

Designs and manufactures packaged boilers "A", "O", "D" Type, Modular "D" type packaged and field-erected boilers, International Lamont line of high temperature hot water generators, and auxiliary equipment. Indeck has over 5,000 successful boiler installations in 45 countries.

JASC

Engineers and manufactures actuators and fluid-control components for power generation, aerospace, defense, and research applications to improve operational capability and performance.

KnechtionRepair Tools

Manufactures tools designed to make thread repairs to both the female and male ends of cross-threaded compression fittings. In most cases, the repair will be accomplished without removing the tube from the system. This saves the O&M tech time and avoids additional downtime.

Kobelco Compressors America

Provides robust, high-efficiency fuel-gas compressors for use with all major types of gas turbines—including GE, Mitsubishi, Alstom, Siemens, Rolls-Royce, and Solar. Over 300 of the company's screw-type compressors have been supplied for gas turbines.

Liburdi Turbine Services

Advanced repairs employ the latest technologies and are proven to extend the life of components for all engine types. Company specializes in high-reliability component repairs and upgrades for blades, vanes, nozzles, shrouds, combustors, and transitions.

M & M Engineering

Provides failure analyses and related services to industrial and insurance-company clients. M&M's expertise includes corrosion in boilers, steam turbines, generators, combustion turbines, deaerators, feedwater heaters, and water and steam piping.

Mechanical Dynamics & Analysis

One of the largest turbine/generator engineering and outage-services companies in the US. MD&A provides complete project management, overhaul, and reconditioning of heavy rotating equipment worldwide.

Mee Industries Inc

Pioneered gas-turbine inlet fogging technology more than 20 years ago. Ever since, MeeFog™ systems have set the standard for cost-effective power augmentation. MeeFog has been used by, or approved by, every major GT manufacturer in the world.

Membrana, a Polypore company

Market-leading producer of microporous membranes and membrane devices used in healthcare and industrial degassing applications. The Industrial & Specialty Filtration Group manufactures Liqui-Flux® ultrafiltration and microfiltration modules as well as Liqui-Cel® membrane contactors.

Moran Iron Works

Global fabrication company committed to providing efficient processes, flexibility, and adaptability to ensure projects are completed on schedule. Moran specializes in one-of-a-kind fabrication and replacement of critical turbine components.

NAES

One of the world's largest independent providers of operations, construction, and maintenance services, provided through a tightly integrated family of subsidiaries and operating divisions. NAES services include O&M; construction, retrofit, and maintenance under dedicated long-term maintenance or individual project contracts; and customized services designed to improve plant and personnel effectiveness.

National Electric Coil

Leading independent manufacturer of high-voltage generator stator windings with expertise in design and manufacturing of stator windings for any size, make, or type of generator. This includes diamond coils, Roebel bars—including direct cooled, inner-gas, and inner-liquid cooled bars—and wave windings.

NEM Energy

A leading engineering company operating globally in the field of steam generating equipment. NEM supplies custom-made solutions regarding industrial, utility, and heat-recovery steam generators for power generation and industrial plant applications.

Nooter/Eriksen

World's leading independent supplier of natural circulation HRSGs behind gas turbines and a single-source supplier of custom-designed heat-recovery systems. NE's annual sales volume includes HRSGs for combined-cycle powerplants whose output exceeds 8 MW.

NRG Energy Services

Backed by the strength and reach of the America's largest independent power generation company, NRG Energy. Company provides plant maintenance solutions to minimize downtime, increase asset availability, reduce ownership costs, and boost profits. Company delivers custom-tailored O&M solutions to meet any generation need, on any scale.

Pneumafil

Major air-inlet filter-house supplier to all major turbine manufacturers for over 45 years. Company manufactures certified, high-efficiency filtration products for all brands, pulse style or static style inlet housings, to ensure maximum turbine output and efficiency.

PowerFlow Engineering

Specializes in servicing variable speed fluid drives for boiler feed pumps with focus on the Voith®, Howden, American Standard, and American Blower brands. Services have recently expanded to include repair and maintenance of turbine start-up couplings.

Powergenics

Leading supplier of industrial electronic circuit-card and power-supply repairs to industrial and power generation customers. Company provides a very high-quality repair at a substantial cost savings from the OEM and other competitors while maintaining a warranty service second to none.

Praxair Surface Technologies

Leading global supplier of surface-enhancing processes and materials, as well as an innovator in thermal spray, composite electroplating, diffusion, and high-performance slurry coatings processes. Company produces and applies metallic and ceramic coatings that protect critical metal components such as in gas turbines.

Precision Iceblast

World leader in HRSG tube cleaning. PIC cleans more HRSGs than any other ice blasting company in the world. It ensures that HRSGs operate efficiently by providing the cleanest boiler tubes possible.

Proco Products

Supplies rubber expansion joints to the power industry in sizes ranging from 1 to 120 in. ID. Proco keeps joints up to 72 in. ID in stock at its Stockton (CA) warehouse and works through an agent/distributor network to supply products to combined-cycle plants.

PSM—an Alstom company

Full-service provider to gas-turbine equipped generating plants, offering technologically advanced aftermarket turbine components and performance upgrades, parts reconditioning, field services, and flexible Long Term Agreements (LTAs) to the worldwide power generation industry.

PW Power Systems

Provides competitive, efficient, and flexible gas-turbine packages rated from 25 to 120 MW. PWPS offers a full range of maintenance, overhaul, repair and spare parts for other manufacturers' GTs with specific concentration on the high-temperature F-class industrial machines.

Rentech Boiler Systems

International provider of high-quality, engineered industrial boiler systems. Rentech is a market leader in providing HRSGs for cogeneration and CHP plants. It is in its second decade of designing and manufacturing high-quality custom boilers—including HRSGs, waste-heat boilers, fired packaged boilers, specialty boilers, and emissions control systems.

ROBLICORP

Serves the industrial gas-turbine aftermarket by supplying an extensive range of renewal items—including ancillary, auxiliary, accessory, and control room spare parts and material. Supplier of new gas turbine spare parts, accessories, components, hardware, filtration, and consumables for LM5000/LM6000, FR5/7/9 HD, GG3/GG4/GG4C/FT4/GG8/FT8/ST6 IGT aftermarket.

Sargent & Lundy

Provides complete engineering and design, project services, and energy business consulting for power projects and system-wide planning. The firm has been dedicated exclusively to serving electric power and energy-intensive clients for more than 120 years.

Sentry Equipment

Engineers, manufactures, and services components for collecting representative samples of steam, water, gas, liquid, slurry, and bulk solids. This enables analytical and operational professionals to gain samples safely and simply, and with repeatable results.

Siemens Energy

A leading global supplier for the generation, transmission, and distribution of power and for the extraction, conversion, and transport of oil and gas. Leadership in the increasingly complex energy business makes it a first-choice supplier for global customers. Known for innovation, excellence and responsibility, company has the answers to the sustainability, flexibility, reliability, and cost challenges facing customers today.

Sound Technologies

Provides engineered silencers and systems for new and replacement gas-turbine applications—including turbine inlet silencing, turbine enclosures, bypass systems, and HRSG inlet shrouds and stack and vent silencers.

SSS Clutch Company

Clutches enable operators to disconnect generators from simple-cycle turbines for synchronous-condenser service. Clutches also find application in CHP plants and in single-shaft combined-cycle facilities where operating flexibility is beneficial.

Stellar Energy

Leading provider of energy plant systems, including turbine inlet-air chilling and TIAC with thermal-energy storage, district cooling, modular utility plants, and CHP. Steller offers a complete range of in-house analysis, design, fabrication, installation, startup and commissioning, and maintenance.

Strategic Power Systems

Provides products and services focused on capturing powerplant operational and maintenance data to develop reliability metrics and benchmarks for end users—including some of the most recognized organizations in the global energy market.

Sulzer

Provides cutting-edge maintenance and service solutions for rotating equipment dedicated to improving customers' processes and business performances. When pumps, turbines, compressors, generators, and motors are essential to operations, Sulzer offers technically advanced and innovative solutions.

TEC-The Energy Corp

Our skills and experience assist GT owners with front-end engineering, procurement of major equipment, and management of engineering, construction, and commissioning of new facilities. From due diligence to detailed design, TEC covers all phases of complex power projects.

Technical Training Professionals

TectraPro produces state-of-the-art training materials for the utility industry which feature detailed 3D model images and videos. Our content can also include customization where site control screens, photos, piping and instrument drawings and documentation are presented.

TEi Services

Offers a full range of heat-transfer products and services and fully trained, certified maintenance personnel. Provides world-class emergency repair services, underpinned by a 75-yr history in the design and manufacture of condensers, feedwater heaters, and heat exchangers.

Thor Precision

Value-added service center provides reverse-engineered rotor bolting for the gas-turbine aftermarket—specifically for Frame 3, 5-1, 5-2, 6B, 7E, 9E engines—including compressor, turbine, marriage, and load-coupling hardware.

Turbine Controls & Excitation

TC&E is an engineering consultation firm focused on turbine and generator controls services. Services include emergency troubleshooting, maintenance support, and equipment upgrades on GE MK I-VIe controls, exciters, and LCIs.

Turbine Generator Maintenance

Provides turnkey field service maintenance for all turbine/generator components. TGM services the turbine, generator, exciter, control systems, and auxiliaries either individually or in any combination. Its service area includes the US, Caribbean, and South America.

Universal AET

Global engineer and manufacturer of acoustic, emission, and filtration systems. Systems portfolio includes a vast complement of silencers, catalysts, and filters for blowers, vacuum pumps, vents, diesel/gas engines, gas turbines, and compressors.

Universal Plant Services

Specializes in the maintenance, repair, and overhaul of gas and steam turbines, centrifugal and reciprocating compressors, as well as all rotating equipment, with qualified millwright and field machining specialists.

Victory Energy

Offers all types of industrial boilers: watertube, HRSG, firetube, and solar-powered units. Company provides unprecedented support with its rental boilers, spare parts, field service, and auxiliary equipment—including water-level devices, economizers, stacks, expansion joints, and ductwork.

Vogt Power International

Supplies custom-designed HRSGs for GTs from 25 to 375 MW and has extensive experience in supplementary-fired units. Scope of supply includes SCR and CO systems, stack dampers, silencers, shrouds, and exhaust bypass systems.

Young & Franklin

Premier fuel control supplier for combustion turbines for both long-term hydraulic solutions and, more recently, innovative all-electric controls solutions. Product scope supports natural gas, liquid, syngas, and alternative fuels as well as providing air controls to provide proper fuel to air mixtures.

Zokman Products

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.

SPS partners with OSIsoft, MapEx to collect, analyze plant operating data

Strategic Power Systems Inc (SPS), OSIsoft, and MapEx Performance Monitoring are partnering to deliver data-driven solutions to the energy market. Control technology and data management systems have improved the speed and accessibility to process quality data. Solutions available through the partnership capitalize on automated data capture and transformation, advanced analytics, reliability/availability/maintainability (RAM) benchmarking, and thermal performance monitoring.

"This partnership will allow each customer to receive a real, measurable return through reduced manual effort, improved data accuracy and fidelity, and access to timely and current RAM and thermal-performance metrics essential for driving down O&M costs while ensuring the reliable performance of the powerplant," SPS CEO Salvatore A DellaVilla Jr said.

There are many reasons to celebrate in Las Vegas. Rain is one of them. And when it puts a rainbow over your plant, it's super special. Production Technician Johnny Nelson captured this moment at the Harry Allen Generating Station

Powerplant owners and operators now can to use OSIsoft's Connected Services secure technical and commercial framework to transfer their operating information into SPS's Operational Reliability Analysis Program (ORAP) system, which already contains 20 years of RAM data. The benefit to users, explains OSIsoft Senior VP Martin Otterson, is the ability to make data-driven decisions using real-time, historical and benchmarked data, and to leverage the insights of experts.

Dr Rodney R Gay, CEO of MapEx, added the following to the discussion: "The marriage of MapEx thermal performance monitoring with ORAP reliability benchmarking will, for the first time, create a complete and consistent set of information allowing plant operators to understand and quantify the tradeoffs necessary to optimize operational strategies."

Shaft grounding, remote monitoring of data collected

Important to attend user group vendor fairs for two important reasons: It's where the food and adult beverages are, and where you'll almost always see something of value that you were not aware of. The CCUG/STUG exhibit hall is where the editors learned of Cutsforth Inc's new shaft grounding system and companion monitoring system.

Recall that shaft voltage, left unchecked, can damage turbine/generator bearing surfaces, possibly causing a forced outage. In the extreme, the rotor could be damaged. Cutsforth's shaft grounding and shaft contact assemblies, the editors were told, are designed to prevent this from happening. The latter, mounted on the shaft at the exciter end of the generator (Fig 1), aides in early detection of changes in voltage—including short-duration transients.

The company's shaft constant monitoring system takes grounding technology—grounding systems of various designs have been around forever—to the next level. It is designed to collect, store, and pass critical voltage information to plant personnel for analysis. Plus, the system provides waveform-level information when in-depth analysis is required. It supports common analog outputs, and can be configured for digital outputs to meet the varied communications needs of plants.

Even if not connected directly to the DCS, the system provides performance information on demand via the touch-screen monitor. Data can be downloaded via a USB port at the same monitor housing.

1. Shaft grounding system is installed at the exciter end of the generator

European Commission clears GE's purchase of Alstom generation, transmission assets

However, there's still work to do to address competition concerns. To complete the deal, the parties offered to divest key personnel and the technologically most advanced parts of Alstom's heavy-duty gas-turbine business to continue their development—including:

- Alstom's technology for the GT 26 and GT 36 gas turbines, existing upgrades, and pipeline technology for future upgrades.
- A large number of Alstom R&D engineers who will continue developing Alstom's heavy-duty gas-turbine technology.
- The two test facilities for the GT 26 and GT 36 engines in Birr, Switzerland.
- Long-term service agreements for 34 GT 26 gas turbines already sold.
- PSM.

GE proposed Ansaldo SpA as a possible purchaser of these assets. Logic: The Italian company is an existing competitor in the heavy-duty GT market. It has know-how, experience, and manufacturing facilities for gas turbines and other equipment often sold together with GTs—such as steam turbines and generators.

The commitments offered by GE will allow the purchaser to replicate Alstom's previous role in the market, thereby maintaining effective competition. GE can complete the acquisition of Alstom only after the EC has formally assessed and approved divestiture of the assets listed above.

The US Dept of Justice issued a companion order to the EC's, both released on September 8, requiring GE to divest PSM to resolve DOJ's competitive concerns in the antitrust lawsuit it had filed to block the proposed acquisition.

New outage management software promises shorter outages, reduced risks, lower costs

Enterprise Processes, Planning, and Performance (ep^3) releases its Outage Management Metrics (OMM) system to help owner/operators manage outages with greater efficiency and fewer resources. OMM is but one component of ep^3's Quad C® advanced software platform for optimizing maintenance and engineering, asset management, and operations activities.

A key feature of OMM is that it continuously improves the outage planning process by gathering user input and building organizational intelligence, making subsequent outages more efficient and effective. The hosted software easily transfers, ensuring that critical institutional knowledge remains with the asset.

Malcolm Hubbard, ep^3's director of operations and customer support and a former plant manager, told the editors he has faced the same challenges every plant manager confronts during an outage. This experience contributed to the design of a software package that's easy to use and able to address the needs of both plant and asset managers. Hubbard said it enables users "to achieve best practices which will minimize outage schedules, reduce risks, and lower vendor costs."

According to Dwayne Boyer, O&M manager at New Athens Generating Co, a G-class combined-cycle plant in New York State, "Most outage software platforms have critical shortcomings that delay operations and elevate both risks and costs. ep^3 brings extensive hands-on experience and a unique software design approach to an age-old process."

Critical Component Management (CCM), the second application in the Quad C suite, is scheduled for release this fall. It uses field-capable tablet photo apps to allow for efficient and accurate real-time collection of necessary asset and parts data—such as maintenance history, validation of component position, and unit and associated outage ID.

AP+M expands product line, geographic coverage

Aviation Power & Marine Inc (AP+M) is expanding its worldwide industrial gas turbine (IGT) spare-parts and service offerings with product-line extensions into component maintenance, repair and overhaul (MRO), and wiring-harness manufacturing, while extending its market reach into Europe, Middle East, and Africa.

The company recently began integrating its IGT component MRO capabilities in Boynton Beach, Fla, AP+M's headquarters location. Included in the initial effort are hydraulic actuators for variable bleed valves, variable stator vanes, and variable inlet guide vanes, as well as hydro-mechanical/pneumatic valves—such as bleed and check valves. The company is adding IGT cable and harness manufacturing capability to provide a cost-competitive solution to operator wiring-harness reliability issues and spare-parts provisioning.

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A uniquely designed tool that will repair your cross threaded industrial Swaged type compression fittings in seconds!

KnechtionRepair tools are designed to make thread repairs to both the internal/female and external/male threads of industrial standard two ferrule Swaged type compression tube fittings. With its uniquely designed holder and hollow bore tap, damaged threads are easily repaired.

Available now tap and die repair kits for 1/4", 3/8", 1/2", 5/8" and 3/4" tube fittings. Coming soon repair tools for your Hydraulic JIC , Aircraft AN fittings and turbine T/C fittings. KnechtionRepair also takes special orders for your problem connections.

KnechtionRepair tools are 100% manufactured in the USA. Order your tools today and save on fitting replacement , down time and money! To view a video demonstration of the thread repair process and watch a live pressure test visit us at www.knechtionrepair.com

For more information and to place an order email info@knechtionrepair.com or phone (907)688-5051
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AGT Services specializes in providing generator test, inspection, and repair solutions, coupled with expert restorations and expedited delivery of components to repair or rewind any Steam, Gas, or Nuclear turbine generator.


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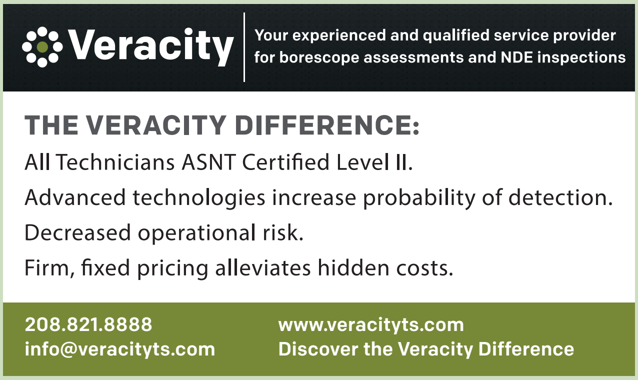
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Inspection guide for drum-level instrumentation

The 2015 edition of "Boiler Inspection Guidelines for Drum Level Instrumentation," issued by Clark-Reliance Corp, concisely presents inspection requirements for ease of reference by O&M personnel. The basis for the seemingly indestructible, spiral-bound 5.5 × 8 in. book is Section I of the ASME Boiler & Pressure Vessel Code. It includes requirements for water columns, water gage valves, gage glass, remote level indicators, magnetic water-level gages and water-column isolation shutoff valves.

The information is up-to-date and incorporates 2013 Code changes, and recommendations from Section 7. Additionally, the guidebook lists the most common non-compliant drum-level equipment arrangements and recommended solutions. The book is free to qualified recipients (visit www.boilerinspectionguide.com).

BRIEFS

First Independent Rotor Services of Texas (FIRST)/Technical Bolting Solutions (TBS), Houston, announces the addition of Ken Knecht to its team of gas- and steam-turbine solutions providers. President Paul Tucker said Knecht brings over 30 years of rotating-equipment expertise to FIRST's Turbine Overhaul and Special Products Div. He will assist end users onsite with turbine mods and upgrades, vibration analysis/correction, balancing, and project supervision (technical advisor).

Retirements are taking a deep bite out of the industry's technical brain trust in 2015. Learned at the CTOTF's™ 40th anniversary meeting, just concluded at the Coeur d'Alene Resort in Idaho:

- Bill Simko, former director of generation engineering for NV Energy, and Dan Giel, CT program manager for Duke Energy's Combustion Turbine Services group, retired a few months back. Simko was known to the group for his outstanding presentations; Giel was the vice chair of the CTOTF's GE (E-Class) Roundtable and a former member of the 7F Users Group steering committee.
- Paul White, PE, consulting engineer for Dominion Resources Services Inc, and Ray Martens, managing director of Klamath Cogen and Klamath Peakers, are retiring before year-end.
- Wickey and Mike Elmo (Goose Creek Systems Inc) retired as the CTOTF coordinators and conference organizers—a trite titles for all they have done in the last two decades—at the close of the fall meeting (p 70). They continue to serve the Frame 6 Users Group (Fig 2).

2. Wickey Elmo, conference coordinator for the Frame 6 Users Group, receives the 2015 John F D Peterson Award for dedicated service to the industry from Co-chair Jeff Gillis (right) and Peterson (left) for whom the award is named

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