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Contact: Sheila Vashi, conference manager
sheila.vashi@sv-events.net
www.7Fusers.org

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Chateau on the Lake
Branson, Mo
Contact: Gabe Fleck, chairman
gfleck@aeci.org
www.501d5-d5ausers.org

Frame 6 Users Group

2018 Conference and Vendor Fair
June 11 – 14
Marriott Sawgrass Golf Resort & Spa
Ponte Vedra Beach, Fla
Contact: Greg Boland, conference manager
greg.boland@ceidmc.com
www.Frame6UsersGroup.org

OVATION USERS' GROUP

31st Annual Conference
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Westin Convention Center Hotel
Pittsburgh, Pa
Contact: Kathleen Garvey
kathleen.garvey@emerson.com
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COMMENTARY

What the digital revolution means for electricity

The changing nature of electric supply

Special to the COMBINED CYCLE Journal

Jason Makansi, chairman, Editorial Advisory Board

What's happening *inside* the fast-growing, hugely profitable, digital behemoths—one characterization is the "Big Five," namely, Amazon, Apple, Facebook, Google, and Microsoft—may be more important than what the electricity industry sees from the outside.

We know they are driving the industry towards renewable energy through direct investments in solar and wind facilities and green electricity purchases. We know they are pushing products and services for electricity consumers, such as smart thermostats and home automation devices, to manage demand to lower levels.

One of these firms, however, has an array of internal programs and policies which may be astounding to many. For example, the company burdens (think of it as a tax or penalty) every business unit with a price for carbon that is 40% higher than the prevailing market price.

Corporations charge business units for a variety of "services"; in some cases, these are called "indirects" on the unit accounting statement. But an internal carbon tax is something different.

This becomes a powerful incentive for executives and directors to drive towards a progressively lower carbon footprint. The taxes collected are then directed into a clean energy fund, used to support innovation and technology which reduce carbon and leads the company to its carbon neutral goal.

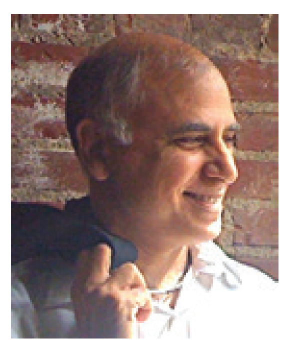
If that's not enough, this company, according to a presentation delivered at the Ten West Innovation Conference in Tucson, October 2017, also is beginning to take on the carbon burden associated with customers for its cloud-based services.

The internal cost of energy at this company includes not only, for example the cost of utilities or the cost of an airline ticket, but also the cost to offset the carbon associated with both. Carbon impact becomes a line item in the budget for every business unit. Electricity consumption, however, is the primary source of carbon emissions for its internal operations. Another metric being considered is "emissions per housed employee (direct and contractors) per square foot."

It doesn't take a genius to see that such a program can drive behavioral changes far beyond the company itself as well as drive demand for energy-efficiency and demand-management related products and services. According to a company white paper, moving customer services to the "cloud" in itself can reduce energy use and carbon footprint by at least 30%.

Employees also are encouraged to find ways to reduce carbon impact for the company and in their personal lives, including use of mass transit, energy conservation, organic farming, and local resources. It would seem straightforward that the other digital Big Five firms, and the second and third tier firms, are implementing similar programs internally, since they would benefit in similar ways.

Traditional electricity industry players need to take note: Sustainability and carbon neutral programs are more than slogans, suggestion boxes, and thick documents written by consultants sitting on shelves in the C-Suite. For these digital firms, they are driving productivity and profitability. And their profitability is undoubtedly going to be revenue losses for traditional players.



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*Carahalios Media is the exclusive worldwide advertising sales organization for the COMBINED CYCLE Journal. Business offices are at Carahalios Media, 5921 Crestbrook Drive, Morrison, Colo 80465.

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Liquid Fuel Check Valves Features

Knife edge seal to provide superior contamination tolerance preventing combustion gas blow back and fuel system evacuation.

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Material construction withstands high temperature excursions without liberating material particles and clogging critical fuel nozzle passages during subsequent flow of fuel.

Purge Air Check Valves Features

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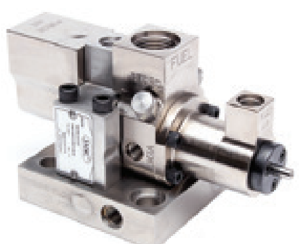
Material construction withstands high temperature excursions without liberating material particles and clogging critical fuel nozzle passages during subsequent flow of fuel.

Enhanced Performance Hardware

Second generation designs offer significantly improved fuel system performance due to the reduction of diesel carbonization on valve internal components.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Check Valves

Maximum Reliability

Water Cooling Technology Provides Increased Operating Intervals Between Liquid Fuel Runs

ALL NEW

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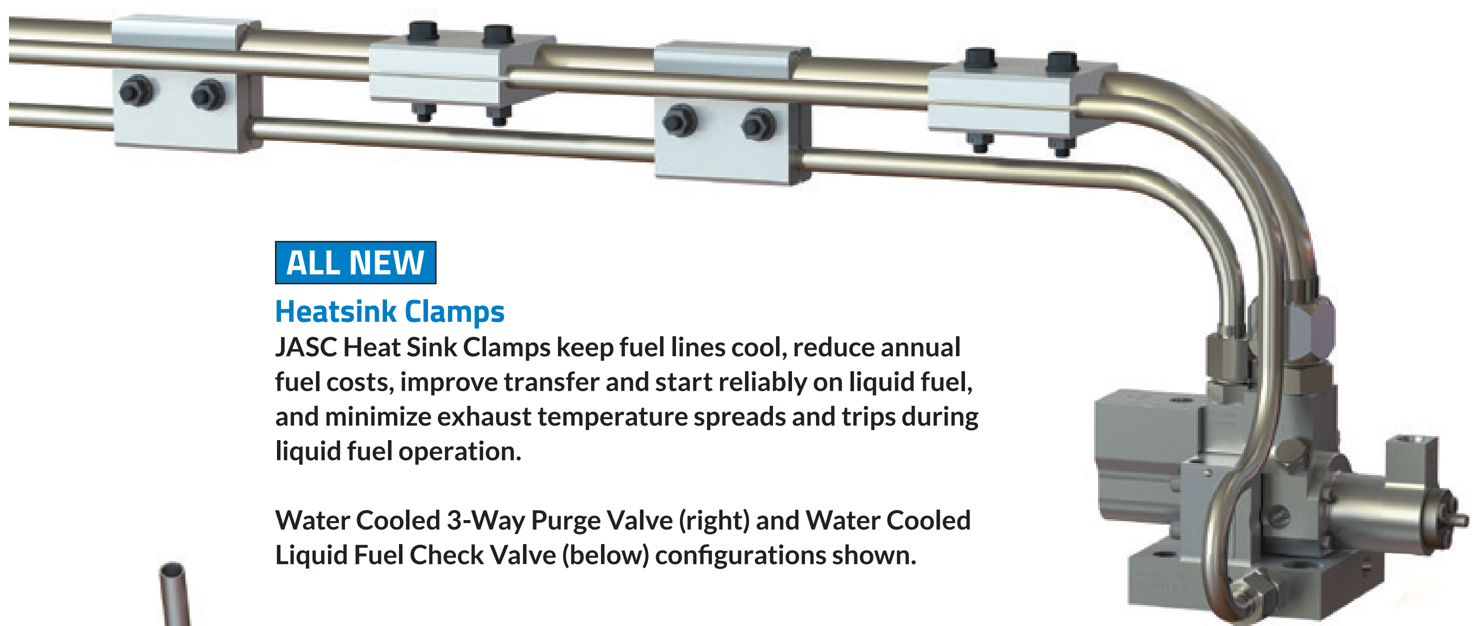
Water cooled fuel controls utilized to negate the impact of coke formation and maintain ANSI class 6 sealing in the checked direction.

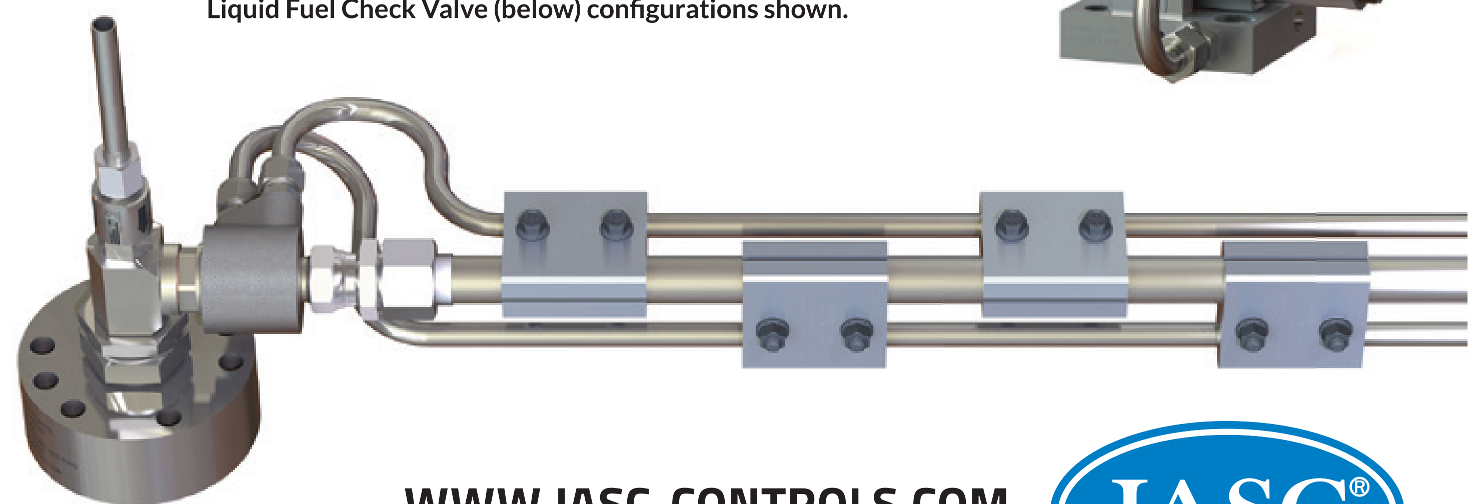


ALL NEW

Heatsink Clamps

JASC Heat Sink Clamps keep fuel lines cool, reduce annual fuel costs, improve transfer and start reliably on liquid fuel, and minimize exhaust temperature spreads and trips during liquid fuel operation.

Water Cooled 3-Way Purge Valve (right) and Water Cooled Liquid Fuel Check Valve (below) configurations shown.



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Best Practices Awards

One of the biggest challenges facing owners and operators of generating assets in deregulated markets is the need to continually improve the performance of their facilities—to increase revenues and decrease expenses. One component of this goal of "continual improvement" is best practices. These are the methods and procedures plants rely on to assure top performance on a predictable and repeatable basis.

The Best Practices Awards program, launched in late 2004 by **CCJ**, has as its primary objective recognition of the valuable contributions made by owner/operator personnel to improve the safety and performance of generating facilities powered by gas turbines. The program continues to evolve by encouraging entries pertinent to industry-wide initiatives.

In 2017, plants were recognized for best practices in water management, O&M, performance improvements, fast start procedures, monitoring and diagnostics/predictive analytics, outage management, safety, and workforce development. Nearly 40% of the entries focused on performance improvement, reflecting the need for plant personnel to squeeze more out of the assets in their care to remain relevant in the highly competitive generation market.

O&M best practices dominated in the early years of the program, then plant focus shifted to safety. Both of those areas remain important, with nearly one-quarter of the 2017 entries having an O&M focus, 17% safety. One reason those percentages have dropped over time: The low-hanging fruit has been harvested and many best practices profiled in years past have been adopted industry-wide.

There are two levels of awards to recognize the achievements at individual plants: Best Practices and The Best of the Best (BoB). Five BoB awards presented this year were profiled in the 2Q/2017 issue (Effingham County, Nueces Bay and Barney M Davis, Athens, Green Country, and Woodbridge).

Aero best practices were featured in 1Q/2017 (Edgewood, Exira, Lawrence, Orange Cogen, Riverside, Terry Bundy, Waterside, and Worthington); the 7EA fleet was highlighted in 3Q/2017 (Ferndale, Eagle Point). In this issue, the 7FA and 501F fleets dominate the best practices coverage, with submittals from 501G, 11NMC, and 6B plants adding to industry knowledge.

Amman East

PI system underpins ISO 50001 (energy management) certification

Background. The Hashemite Kingdom of Jordan is one of the world's poorest countries in terms of indigenous fuel resources, importing 98% of the energy it consumes. This makes efficiency of electric generation a priority.

US-based AES Corp owns and operates powerplants on four continents, two in Jordan. They are managed by Meftaur Rahman and account for about one-fifth of the country's installed generating capacity with grid access:

- Amman East Power Plant (IPP1), a 370-MW, 2 × 1 combined cycle powered by two AE94.2 gas turbines, commissioned in August 2009.
- AES Levant (IPP4), a 241-MW diesel plant powered by 16 tri-fuel W18V50DF engines, commissioned in July 2014.

One of AES's goals as a Fortune 200 global power company is to operate its facilities at top efficiency. The company initiated what it calls the AES Energy Star program to communicate internally ways its assets are optimizing operations to reduce energy consumption. Sharing best practices and lessons learned across the enterprise is critical to success.

ISO 50001 compliance is one method AES uses to integrate energy management into the systems and culture of the company. The internationally recognized, externally verified energy management system carries credibility and ensures diligence in program management. This was proven by experience gained earlier in achieving ISO 14001 and OHSAS 18001 certifications.

Challenge. Develop an ongoing program to reduce fuel consumption and CO_2 emissions year over year.

Solution. Achieve ISO 50001 certification. The process began in 2013 with implementation of a gas-turbine inlet fogging system to boost plant output by 30 MW. Recovery of 70% of project capital cost in the first year of operation provided the incentive to develop a structural approach for continuing improvement in energy management. This project was recognized with CCJ's 2014 Best Practices Award for performance improvement. The following year it received a Best Innovation Award from Middle East Electricity.

Management gave its EnMS (for energy management system) program the highest priority among the plant's many business objectives. An internal committee was formed to create a plan for successful 50001 certification, awareness training was conducted for all personnel, guidance documents were developed for heat-rate and efficiency improvement, objectives were developed for all individuals, etc.

Successful projects attributed to the EnMS initiative included the following:

Amman East Power Plant

AES Jordan PSC

420-MW, dual-fuel, 2 × 1 combined cycle located in Al Manakher, Jordan

Plant manager: Meftaur Rahman

- Reduction in house-load consumption.
- Replaced domestic electric water heater with a solar system.
- Replaced halogen street lights with LED lighting.
- Installed motion sensors to control inside lighting.
- Upgraded air-conditioning controls to reduce operating time.
- Reduced A/C power consumption by changing from R-22 refrigerant to R-410a.

Improving heat rate hinged on the ability to collect, analyze, monitor, visualize, and share energy data from multiple sources among team members and systems across all plant operations. To achieve this goal, management invested in PI software from OSIsoft LLC. This critical step, taken in 2015, enabled calculations of technical and financial performance, tracking of auxiliary power consumption, transformer monitoring, etc.

Some of the benefits attributed to PI include the following:

- Enabled the plant to deliver the 370 MW specified in its PPA by correcting to ambient conditions when operating baseload.
- Minimized wintertime derating by providing operators the information necessary to maintain expected output.
- Identified issues with inlet guide vanes.
- Offered the ability to back-up the plant historian and to facilitate billing.
- Solved a transformer load-limit issue by developing a monitoring screen for operators.
- Enabled the monitoring of plant performance from a laptop, anywhere.

Results. Amman East became the first powerplant in Jordan to implement ISO 50001 (2016). In the four years it took the plant to achieve this goal, energy performance improved by 1.7% and CO_2 emissions were reduced by more than 35 million tons. Total cost of the program for the first four years was $300,000 less than the fuel saving.

Project participants: Anas Diab, Anas Hayajneh, Zaher Hasan, Mohammad Alziq, Ahmad Shaweesh

AES Levant

Conserve energy, reduce parasitic load, save money

Challenge. Increasing the efficiency of the power station in a cost-effective manner is a continual goal of plant staff. Please see Amman East best practice for background (left).

Solutions and savings. Plant staff saw an opportunity to greatly reduce costs and house load through the application of a variety of energy conservation projects. After a thorough review of possible areas of implementation and cost-benefit analysis, the plant targeted the following areas to reduce the parasitic load:

- Engine-hall ventilation fans.
- Air management system.
- Lighting and HVAC timers and motion sensors.
- Electrical heat tracing system for residual oil.
- Feeder busbar changeover.

Engine hall ventilation fans. There are 80 fans inside the engine halls for ventilation purposes. Their operation depends on engine-hall temperature (turn on at 100F, off at 90F). Increasing the fan starting temperature to 110F (after OEM approval) saved $348,000 annually.

Air management system. Instrument air system used for balance-of-plant pneumatic controls relied on three compressors running continuously. Daily power consumption was around 1.2 MWh. By better controlling compressor start and stop times, daily power consumption was decreased by half, saving $38,000 annually.

Lighting and HVAC timers and motion sensors. Lighting and HVAC systems for plant buildings were running continuously. Building HVAC timers have been added to reduce A/C to 10 hr/day from 24. Plus, motion sensors have been installed to turn lights on and off as necessary. Annual savings: $15,000 from motion sensors, $25,000 from HVAC timers.

Electrical heat tracing is used for heating heavy fuel prior to engine start. Since shifting to gas, it is no longer needed. The heat-tracing logic circuit was modified to be ON when using oil, OFF on gas. Annual saving: $6000.

Feeder busbar changeover. Four medium-voltage busbars supply the low-voltage busbar to which plant auxiliaries are connected. Each MV busbar serves four engines. If fewer than four engines are started there is at least one MV busbar still importing power from the grid at about $178/MWh. A small modification was applied by changing the feeding busbar on the LV side at any MV busbar with no engines running, so it can be fed from the busbars of the running engines. Annual saving: $25,000.

AES Levant Power Plant

AES Levant Holdings BV Jordan

250-MW, tri-fuel, peaking facility consisting of 16 diesel engines located in Al Manakher, Jordan

Plant manager: Meftaur Rahman

Results. Implementation of these projects has reduced imported power requirements significantly, saving upwards of about $450,000 annually.

Project participants: Laith Jaraabeh, Erfan Ahamd, Ashraf Qasem, Ayman Mobaied, Wael Zghoul, Mohammad Aldabaibah

Serving the entire fleet, from legacy engines to the latest 7F.05s and beyond

The world's largest meeting of frame gas-turbine owner/operators, hosted annually by the 7F Users Group, typically attracts about 250 users and more than that number of commercial attendees representing the nearly 150 companies participating in the vendor fair over two evenings.

The 2018 conference, only a few weeks away in Atlanta (see box), is an easy commute for almost all owner/operators. You can't afford to miss this meeting if your gas turbine has a 7F nameplate. Technologies and solutions for all models in the fleet of nearly 900 engines—from legacy machines up to the latest 7F.05s and beyond—are included in the program.

By way of background, this group formed in November 1991, when there was only one 7F operating in the world. The first meeting attracted 14 users from four generating companies; there was no vendor involvement.

The 2017 conference in San Antonio, chaired by Clift Pompee of Duke Energy, was an unqualified success by every measure. Program improvements focused on GE Day (Thursday). The steering committee worked collaboratively with the OEM to provide a more succinct general session in the morning and allow more time for the popular topical 45-min breakout sessions, which begin after the morning break. The same format is used on Friday as well, but with a different lineup of topics. The breakout format of four subjects addressed in parallel in each time slot allows users to attend half of the topical sessions available.

GE Day 2018. Positive feedback from attendees encouraged the same GE Day format for the upcoming meeting, which consists of opening remarks by OEM experts, Q&A, and open discussion. The 2018 conference chair, Luis Barrera of Calpine Corp, announced the lineup of breakout topics.

For Thursday:

- Compressor. Fleet experience, new Enhanced Compressor options.
- Combustor. Fleet experience with the DLN 2.6+, operability best practices.
- Turbine. Fleet experience, including advanced gas path; post-repair third-stage bucket cracking.
- Exhaust frame. Options for maximizing durability.
- Rotor. Lessons learned from flat-slot-bottom inspections, rotor life-management options.
- Accessories. Update on the most common accessories challenges, plus RCA results for the stainless steel compressor bleed valve.
- Controls. Controls challenges and how to deal with them, discussion of TIL 1622 (lube oil).
- Electrical systems and generators. Maintenance best practices.
- Parts and repairs. How to check parts status and stay informed during the repair process.
- Outages/FieldCore. Outage preparation and execution best practices.

For Friday:

- Batteries. Overview of the technology, its applications, and how batteries could impact thermal generation.
- Complexities of modern blade design. Airfoil design principles and why they're relevant to an effective maintenance plant; plus, how modern design impacts plant operations.
- Additive manufacturing. Overview of the technology, its applications, and impacts on supply chain and new product design.
- Arming the digital worker. Interactive discussion on how new technology is enabling more effective outages from planning to execution.
- Next generation GT technology (7FA.05 and HA). What owner/operators need to consider in running the latest gas turbines.

Training of plant O&M personnel is a top priority of many asset owners and operating companies today given the challenge in finding experienced applicants for jobs vacated by retirements of the industry's most knowledgeable. Recognizing this need, the steering committee and GE collaborated to offer GT 101 on Monday afternoon: A four-hour deep dive on gas-turbine fundamentals spanning performance, combustion, controls, inspections and hardware considerations.

Industry newcomers—those with fewer than three to five years of deck plates experience—will benefit greatly from this concentrated program and be better prepared for the sessions to follow. For more experienced personnel, it is a very worthwhile refresher. Amazing how much one can forget in such a short time.

The user-only sessions, held in high esteem by plant personnel, begin Tuesday morning and run until the afternoon break, then pick up again

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7F USERS GROUP

2018 Conference and Vendor Fair

Atlanta Marriott Marquis
Atlanta, Ga • May 7 – 11

Steering Committee

Chair: Luis Barrera, *Calpine Corp*
Vice Chair: Bryan Graham, *Entergy Corp*
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Ed Fuselier, *Kindle Energy LLC*
Jeff Gillis, *ExxonMobil Chemical Co*
Sam Graham, *Tenaska Inc*
Kaitlyn Honey, *Xcel Energy Inc*
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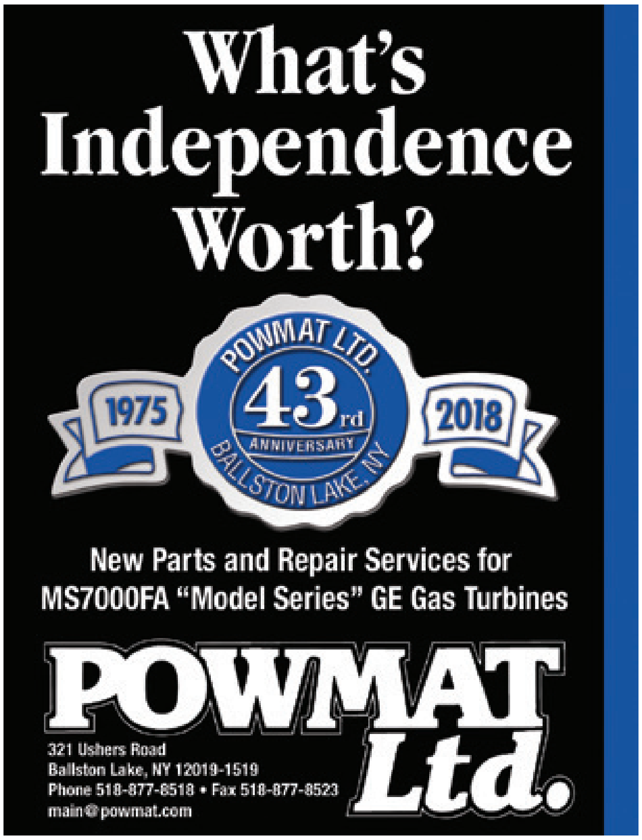


on Wednesday morning. The user presentations and interactive discussions deliver unbiased O&M experience you can't get anywhere else. Sessions on compressors, safety practices, performance and controls, auxiliaries, combustion, turbines, and generators run for one to two hours, depending on the subject. This portion of the program concludes with "7F Top Issues," which includes discussion of best practices submitted by 7F owner/operators to CCJ's annual program.

A dozen vendor presentations, invited and vetted by the steering committee, are on the program Tuesday and Wednesday afternoons, following the refreshment breaks. Arrangement is two sessions each day with three presentations conducted in parallel in each session. Here are the topics:

- Big data for turbine-oil condition assessment.
- Fire protection: Upgrades required by NFPA 12 for CO_2 systems, water mist suppression systems.
- Rejuvenation heat treatment of single-crystal GT blades.
- Generator diagnostics for asset management.
- 7FA compressor offerings from a third-party supplier.
- HRSG fast-start considerations (hot and warm).
- Auto-tuning and optimization for improving efficiency.
- Key considerations for performance upgrades and rotor exchanges, through the eyes of an attorney.
- 7FH2 stator deficiencies.
- Failure mitigation of non-seg phase bus.
- Advanced thermal-spray TBC.
- Rotor lifetime extension.

Steering committee, OEM discuss ways to improve field service

Members of the 7F Users Group steering committee recently visited GE's Houston Learning Center (HLC) to become acquainted with the new training facility and to discuss with the OEM the needs, expectations, and concerns of owner/operators to ensure improved field-service outcomes. CCJ Senior Editor Scott Schwieger was an invited observer.

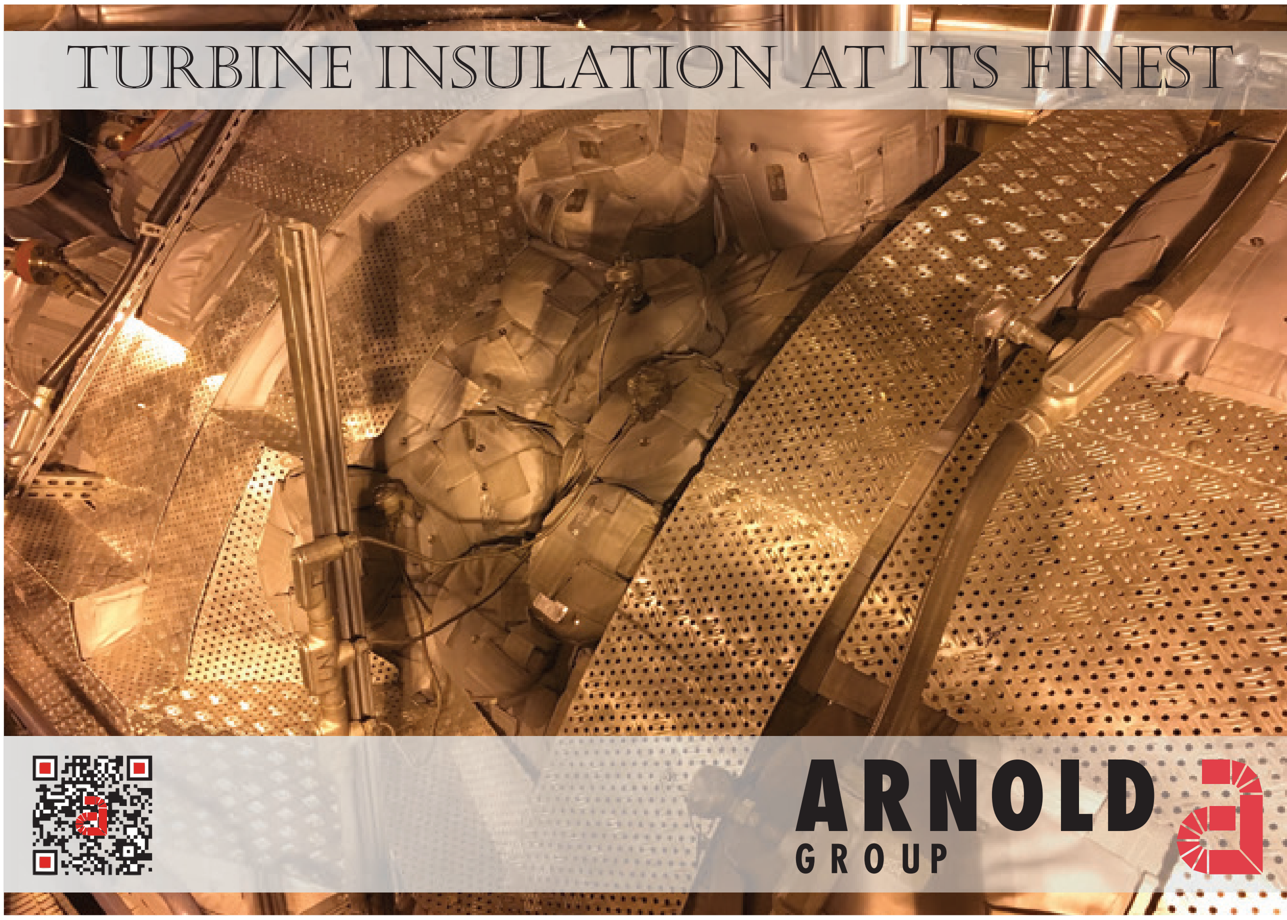
Background. In 2014, GE Power Services Training acquired and repurposed the Houston Service Center on Wallisville Road. The 15-acre campus has been revitalized to accommodate field-engineer, craft, and customer training in aeroderivatives, controls, excitation, gas and steam turbines, generators, installation and commissioning, and inspection and life-extension services.

HLC is designed to accommodate up to 400 students per day in its three main buildings, ranging from 20,000 to 45,000 ft^2. Building One houses 9E, 7E, 7F, and D11 heavy-duty equipment in its bays, as well as state-of-the-art classrooms and distance-learning suites. Building Two is occupied by FieldCore—GE's independent industrial field-services company—and dedicated to craft training. Building Three has areas focused on aeroderivatives, controls, and excitation training.

Strength in numbers. The 7F Users Group steering committee works diligently to support owner/operators by fostering a healthy relationship with the OEM. Through their deckplates feedback, and the open ears of the training staff, the entire fleet will benefit.

Jim Rosen, GE Power's technical training manager, opened the floor for questions/comments after providing an overview of the facility and available training modules. The discussion was meaningful given the five steering-committee participants (photo) combined have well over 100 years of gas-turbine experience; plus, two are graduates of the GE Field Engineer program.

Suggestions of areas for program improvement and streamlining included the following:



- More emphasis on reading manuals, finding drawings, and familiarity with parts/part numbers.
- Increased focus on people skills and leadership training to improve face-to-face customer and crew relations.
- Acceptance and understanding of the customer's safety culture.
- Cost tracking and financial understanding with respect to change orders.
- Openness in communicating escalating issues to site management in a timely manner.
- Use of shared, consistent forms for field reports—such as shift-turnover protocol and daily outage updates.
- Sharing level designation (and what that means) and training courses of study for all field engineers onsite.
- Struggles with turnover package in outage, as technical field advisors often take a back seat to experienced craft workers.
- More timely responses for reasonable customer inquiries.

Response. The concerns have not gone unnoticed and the OEM already has instituted modifications to the training program to address field issues. All engineers in customer-facing positions will have more training in communications and writing. A new app in development, called "Field Vision," is designed to standardize checklists that are easily shareable between organizations. GE is working on a "level" system of qualification with full sign-off requirements to be certified for a certain level of training, which can be more easily communicated to customer. And, finally, the "Operations Excellence Quality" group is being reinvigorated for enhanced QA/QC and rigorous training foundations.

Users are encouraged to participate in more in-depth discussion on training, outage management, and safety at the upcoming annual conference. CCJ

Frame 6B turbine/generator, for hands-on training of future FieldCore engineers, sits behind members of the 7F Users Group steering committee visiting the Houston Learning Center. From left to right, Justin McDonald (Southern Co), Scott Schwieger (CCJ), Jeff Gillis (ExxonMobil), Luis Barrera (Calpine), Bryan Graham (Entergy), Chris Thompson (GE), and Tricia Keegan (Emera)

Whitewater

LSP-Whitewater LP

Owned by Tyr Energy

Operated by NAES Corp

275-MW, dual-fuel, 1 × 1 combined-cycle cogeneration facility located in Whitewater, Wisc.

Plant manager: Roy Killgore

Procedure reduces post-outage recovery time, minimizes pitfalls on restart

Challenge. Plant management was not happy with the length of time it was taking to recover from extended outages, or with the pitfalls often encountered during the first start after an outage. These included missing the proper equipment line-ups and doing an average job of leak-checking, among others.

Plant's goals were to maximize availability and improve post-outage first-start reliability. Since major outages occur infrequently, senior personnel wanted to develop a formal procedure; relying on memory is inadequate for ensuring staff is following the proper sequence and not missing line-ups, etc.

Solution. Management assembled a team to develop the Major Outage Recovery Procedure presented in the sidebar. This checklist provides the steps necessary to take the plant smoothly from the "LOTOed" condition at the end of the outage through the first start. It follows a logical sequence and includes such items as these:

- Specific line-ups based on post-outage equipment conditions. Example: "If the cooling tower is drained, leave the process and sparging steam isolation valves closed."
- Specific equipment checks, based on outage work performed. Example: "Perform fuel-oil tubing leak checks if gas-turbine combustor work was performed."
- Transitioning from temporary equipment cooling back to auxiliary cooling water (ACW).
- Establishing proper chemistry control for initial fills of the cooling tower and HRSGs.
- Tracking, minimizing, and/or eliminating abnormal conditions—such as line-ups—throughout the procedure.

The team agreed that the procedure would be a "living document" –one improved and updated from outage to outage.

Precautions:

- Consider the Operational Checklist as a guideline that likely will require modifications to customize for your plant. The baseline procedure you develop should be reviewed before each use as it also may need modifications depending on end-of-outage conditions, equipment out of service, etc. Specific items not applicable for a given restart should be lined out.
- Wear appropriate PPE and follow applicable Material Safety Data Sheets when venting chemical feed pumps.
- Important: If any of the air-operated GT fuel-gas valves were worked on during the outage, keep the manual isolation valve upstream of the OST closed until the applicable valves are calibrated and stroked. Note this on the "Abnormal Conditions Sheet" that you should have as an addendum to the checklist.
- Check and resolve the Abnormal Conditions Sheet throughout the procedure.
- Add special instructions as applicable.

Results. The team developed the initial draft of the Operational Checklist in the middle of the 2014 combustion inspection (CI) and implemented it at the end of the outage. Plant has since used the checklist after every extended outage, including the 2015 major inspection and 2016 BOP outages. Staff continues to improve the checklist whenever a gap in the procedures is noticed.

Plant operators and management agree on the following benefits of the effort:

- Much less confusion over "what do next" with regard to equipment restoration, line-ups, etc.
- Faster restoration of proper cooling-tower and HRSG chemistry thanks to specific procedural steps for initial chemical dosage and hotwell pH correction.
- Noticeably fewer piping and equipment line-ups found out of position.
- Gas leak checks, gas flow testing, and fuel-oil tubing leak checks—all referenced in the procedure—were properly performed in logically ordered sequence following the CI.
- Since implementation of the procedure, plant has not experienced a delay or equipment protective action caused by a missed line-up, abnormal condition, or other post-outage oversight.

Project participants:

Randy Culler, lead operator
All control-room operators
Dan Tesch, maintenance supervisor
Mark Barrett, operations supervisor

New LOTO qualification program results in zero violations

Challenge. Plant management was dissatisfied with the number of lockout/tagout (LOTO) violations cited and wanted a more effective, fail-safe process.

Solution. First, LOTO training was made a required annual event. Plant also improved its old training approach, upgrading it to an interactive tabletop exercise: Trainees must implement lockout/tagout on selected equipment. In addition to covering required topics, the training program now incorporates real scenarios and lessons learned from previous LOTO errors.

Also, LOTO training and qualification are mandatory for new hires. After

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AGTSI Teams with Eaton on Global Product Distribution for Aeroderivative Market.
In a new agreement with power management company Eaton, Aeroderivative Gas Turbine Support, Inc. (AGTSI) of Boca Raton, Florida, has been selected as Eaton's official global distributor for aeroderivative, industrial and commercial marine engine components and services.
Eaton's products include dynamic and static seals, hoses and fittings, as well as specialty lube system sensors and components. Eaton's product reliability is proven across all gas turbine applications including aerospace, ground based industrial, power-generation and marine propulsion.
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Aeroderivative Gas Turbine Support, Inc. (AGTSI) was established in 2004 and is a global stocking distributor of parts and assemblies for industrial and commercial marine gas turbines.
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OPERATIONAL CHECKLIST of activities to perform prior to first start after an

Note: Steps may be done concurrently or out of order. Initial each step performed; if a particular step is not applicable, mark it N/A.

1. Ensure the gas-turbine CO_2 fire-protection root valve is tagged closed for any non-line opening/non-CSE/non-hot work being conducted in the GT mechanical package.
2. If/when conditions allow, enable the GT lube-oil heater. Oil temperature must be above 70F to start a LO pump.
3. Once cooling-tower work is complete, clear the cooling-tower LOTO.
4. Fill the cooling tower.
5. Start a main circulating-water pump when the tower level is higher than 40 inches.
6. Once chemical feed pumps are vented, start one and dose the tower at 100% output for nine hours. This will give near the 17-gal requirement to treat the initial fill of water. Continue dosing the tower until the dioxido(dioxo) molybdenum tracer is in-spec.
7. Line up the ACW pumps and system as applicable. Vent the pumps and suction strainers.
8. Start an ACW pump.
9. Line up the following loads to ACW (includes swapping from temporary cooling), as applicable:
   - GT lube-oil cooler, vent the water side.
   - Steam-turbine (ST) lube-oil coolers, vent the water sides.
   - GT control oil.
   - ST electrohydraulic control-oil skid.
   - Air-compressor aftercooler.
   - Auxiliary-boiler blowdown tank.
   - Vent GT hydrogen cooler if necessary.
10. Line-up raw-water cooling to the sample panel, including the recirc skid and outlet to ACW.
11. Feed phosphoric acid to the ACW system at 100% output for 12 hours. Test for orthophosphate and continue dosing until in-spec. See priming instructions on the back of the five-function valve. Circulate with a circ-water and ACW pump until chemistry is in-spec. The circ-water pump then may be secured.
12. Start up the ST lube oil system and place the unit on turning gear (TG). This may be done earlier if raw water is hosed up to the LO coolers. Line-up the LO vapor extractor, LO pump, and dehumidifier. Note, that the LO temperature must be above 50F prior to starting a lube-oil pump and over 70F prior to putting the machine on TG.
13. Once ST work is complete, start up the steamer's electrohydraulic oil system.
14. Once GT work is complete or conditions allow, clear the CI/HGP (combustion inspection/hot gas path) LOTO, start a lube-oil pump, and place the GT on turning gear. This may be done earlier if raw water cooling is hosed up to the lube oil cooler. Note that LO temp should be above 80F before putting the engine on turning gear.
15. Once GT work is complete or conditions allow, start up the control oil system.
16. Perform the critical-valve stroke checklist as early as conditions allow.
17. Once HRSG steam and waterside work is complete, clear the HRSG waterside LOTO.
18. If the GT generator was purged to air, pressurize/swap to CO_2, then to hydrogen. Perform a generator air test, if needed, prior to purging to CO_2.
19. Verify the GT generator hydrogen-purity blower is operating and purity is 95% – 99%. (A 100% indication indicates a problem with the blower.)
20. Pressurize the fuel-gas heater.
21. Leak-check applicable portions of the fuel-gas piping if work was performed during the outage.
22. Spark-check GT igniters.
23. Once the CT exhaust and HRSG are closed up, clear HRSG fireside LOTO.
24. Perform DCS point search. Re-enable alarm and limit checks. Place off-scan points back on scan.
25. Fill the hotwell and vent the condensate pumps.
26. Start a condensate pump and establish normal recirculation through the condensate storage tank. Start the condensate amine pump and raise hotwell pH to 9.6.
27. Prepare for filling the HRSGs by performing the following:
   - Confirm/verify that all evaporator and economizer drains valves are closed.
   - Check superheater drains are throttled open and lined up to the blowdown sump.
   - Check balance-of-plant (BOP) drains open.
   - Check drum vents open.
   - Check steam stops and non-return valves open.
28. Once hotwell pH is established, fill HRSG drums, in accordance with the "Filling Drums after HRSG Work Operational Summary." Vent boiler feed pumps if they, or associated piping, were drained.
29. Crack open sparging steam to the HRSG evaporators. As the drum temperatures warm, the sparging steam may be opened up more.
30. Shut HRSG drum vents once the applicable drum pressure reaches 15 psig.
31. Check and resolve the Abnormal Conditions Sheet as applicable.
32. Fuel-oil leak check/transfer preparations: If fuel-oil tubing leak checks are necessary, line up the water injection skid the night or day before leak checks are scheduled to begin, in accordance with

completing LOTO training, new employees are required to pass a LOTO practical factor demonstration (photo) administered by the operations supervisor or lead operator within three to six months of hire that includes the following:

- Oral interview—including such topics as how to perform a start attempt, perform a second check, file a report following tag/lock hanging.
- Successful completion of a LOTO hanging on selected equipment—including a verbal report and proper start attempt on the LOTO equipment.
- Successful second check of a previously hung LOTO that includes intentionally introduced errors (valve out of position, lock/tag hung on wrong isolation point, etc) derived from previous Whitewater LOTO lessons learned.

Employees often fail their first attempt at the practical factor, in which case they must try again at a later date. The objective is to eliminate mistakes by shaping focus and behavior regarding lockout/tagout through

After LOTO training new employees are required to pass a deck-plates exam

extended outage

applicable documentation. If a fuel-oil transfer test is necessary, conduct the OEM's suggested pre-start procedures the day before the test and flush the flow divider.

33. Perform gas-flow testing and leak checks in accordance with "Gas Flow Test After GT Work Operational Summary," if needed. Prerequisites: Install jumpers and LOTO the GT igniter breaker. Run all GT enclosure fans and turn on sufficient generation-bay roof ventilation fans to handle any natural-gas leakage from the turbine. Finally open generation-bay doors to maximize air exchange.
34. At the conclusion of gas flow testing, perform fuel-oil tubing leak checks if desired. Plus:
    - Return GT enclosure fans to auto.
    - Nitrogen-purge the combustion dynamics monitoring system.
35. Perform a "dummy start," if needed, with igniters powered off.
36. Perform an actual test start, if needed.
37. On the first start, after the outage, perform the following:
    - Put enclosure fans into "manual."
    - Turn on enough generation-bay roof fans to handle the "burn off" of anti-seize products.
    - Open generation-bay doors to maximize air exchange.
    - Confirm all cooling-tower chemical feeds are pumping.
    - If fuel-oil tubing leak checks were performed, perform "A-" and "B-" stage water purges, watching for flashbacks to verify "A" and "B" fuel tubing is properly connected.
38. Perform a fuel-oil transfer test, if needed.
39. Secure and lay-up the water injection skid once fuel-oil tubing leak checks and the test transfer are complete.

training and qualification.

Results. Since implementing the new program in late 2014, plant has had no lockout/tagout violations. Plus, there has been a reduction in leading indicators—fewer verbal reports, fewer errors in LOTO form paperwork, etc—associated with lockout/tagout.

Project participants:
Randy Culler, lead operator
Dan Tesch, maintenance supervisor
Mark Barrett, operations supervisor

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- Procedures for the measurement of carryover of boiler water into steam.
- Instrumentation for monitoring and control of cycle chemistry.
- Volatile treatments for the steam-water circuits of power plants.
- Phosphate and NaOH treatments for the steam-water circuits of drum boilers.
- Steam purity for turbine operation.
- Corrosion-product sampling and analysis.
- HRSG high-pressure evaporator sampling for internal deposit identification and determining the need to chemical clean.
- Application of film-forming amines in power plants.

Lea Power Partners LLC

Western Generation Partners

Operated by Consolidated Asset Management Services

604-MW, gas-fired, 2 × 1 combined cycle located in Hobbs, NM

Plant manager: Roger Schnabel

Closed-loop chilled-water monitoring system

Challenge. The gas-turbine inlet chilled-water system is a closed-loop design that includes a 4-million-gal storage tank (Fig 1). The chilled-water system relies on a combination of mild-steel and copper components, and the closed-loop water chemistry must be managed to avoid equipment and piping corrosion. Under-feeding the system with corrosion inhibitor would result in corrosion and over-feeding the extremely large system is costly.

Solution. Working with Nalco Water, the plant installed a 3D TRASAR™ controller to monitor the chilled-water system (Fig 2). It monitors key performance indicators—such as pH, conductivity, turbidity, corrosion-inhibitor residual, mild-steel corrosion rate, and copper corrosion rate—in real time.

1. Inlet air chillers for the two gas turbines are arranged at groups of three (far left and right) with the storage tank in between

The ability to monitor conductivity along with the corrosion-inhibitor residual assures the plant will be notified if an unexpected and rapid loss of costly, treated water were to occur. Plus, it allows the plant to verify corrosion-inhibitor performance by way of online corrosion probes, and predicts when the system must be recharged chemically. The latter is valuable because budgeting and scheduling of the task can be done months or years in advance.

2. 3D TRASAR controller monitors KPIs—such as pH, conductivity, turbidity, etc—in real time

Results. Improved real-time condition monitoring of the chilled-water system provides actual and current information that can be trended. The real-time trends enable personnel to maximize intervals between chemical additions and to predict when to budget for those chemicals.

Project participant: Rich Shaw

Fuel-gas-heater inlet temperature control

Challenge. During periodic system maintenance inspections of the fuel-gas heaters, the copper heat-exchanger coils showed evidence of condensation during operation. Condensate on the copper coils can increase both the maintenance frequency and cost of cleaning.

Solution. The gas heaters are of a closed-loop design with pump-mounted water heaters. At the manufacturer's recommendation, a bypass line with a throttling valve was installed on each of three heaters from the heated-water outlet to the heater inlet (Fig 3). The bypass throttling valve was adjusted to maintain the recommended minimum water-heater inlet temperature to prevent condensate from forming on the copper coils.

3. Gas heater has a bypass throttling valve to maintain the recommended minimum inlet temperature

Results. Controlling the heater inlet temperature prevents condensate from forming on the copper coils, reducing the time and cost of maintenance.

Project participant: Kelvin Mendenhall


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New Harquahala

New Harquahala Generating Co LLC

Owned by Talen Energy
Operated by NAES Corp

1080-MW, gas-fired, three 1 × 1 combined cycles located in Tonopah, Ariz

Plant manager: Andy Duncan

Still correcting design deficiencies more than a decade after COD

Challenge. New Harquahala's three 1 × 1 G-class combined-cycle power blocks are served by two mechanical-draft cooling towers. The middle unit in the plant photo, equipped with two 50%-capacity circulating-water pumps, relies on both towers to satisfy its cooling requirements.

New Harq's circ-water pumps are driven by 6.9-kV motors which receive power directly from the main power feed associated with their unit. Thus, the pumps shut down when power is lost to the unit served.

However, the supply power to the motor-operated discharge valves (MOVs) for the middle unit is split this way: Cooling tower A's motor control center (MCC) supplies power to the discharge valves on A tower and cooling tower B's MCC provides power to the B tower discharge valves. Power to the cooling tower MCCs can be lined up from any of the three generating units.

The logic was designed such that if the MOV were closed, it would trip the circ-water pump to protect it. The pump also would trip if the MOV lost power. This is not an issue for the other two units because they take suction from, and discharge back to, the same cooling tower.

Designers did not consider that if one of the pumps—specifically one on the unit sharing water from both towers—tripped off from loss of power with the MOV open, circulating water would be pumped directly from A tower to B tower, or vice versa. The plant is designed with a cross connect for equalizing the towers; however, circ-water flow at a rate of 60,000 gpm, it is not capable of keeping up. This would certainly cause the receiving cooling-tower basin to overflow.

In 2016 there were two situations where this occurred. One was a fault that occurred on the Unit 3 main feeder breaker which terminated the power to cooling tower B MCC. The second occurrence: A contractor conducting relay tests on Unit 1 accidentally tripped open the switchyard, causing the loss of power to cooling tower A MCC.

Plant personnel conducted a root-cause evaluation (think reliability cause map) to determine what options were available to ensure events, such as stated above, are mitigated. The following options were evaluated:

- Rewire the MOVs back to the main power feed at the unit. This was rejected as very costly.
- Move the supply power for the pumps from the specific unit to the specific cooling tower MCC. Very costly, plus evaluation of the MCC's capacity was required.
- Add a battery backup for the power supply.
- Install an additional positioner on the discharge MOV that receives loop power from the DCS.

Solution. Find and install the most cost-effective option that increases the reliability of the Unit 2 circ-water system to ensure against a basin overflow event. After careful evaluation, staff determined the most cost-effective option was to procure and install the secondary positioner on the discharge MOVs. Loop power from the DCS was available at the discharge MOVs already and required minimal labor for the install. After the management-of-change process for design and implementation was approved the work was completed by plant employees.

Results. This upgrade has significantly increased the reliability of Unit 2's circ-water system and will prevent a tower basin from overflowing if power is lost to one of the two circ-water pumps while Unit 2 is operating.

Project participants:
Nathaniel Larson, lead maintenance technician
Will Emeigh, ICE technician
Kyle Hardy, plant engineer ll

1. New Harquahala's circ-water pumps are driven by 6.9-kV motors (left)

2. Circ pumps would trip if motor-operated discharge valves were to close (right)

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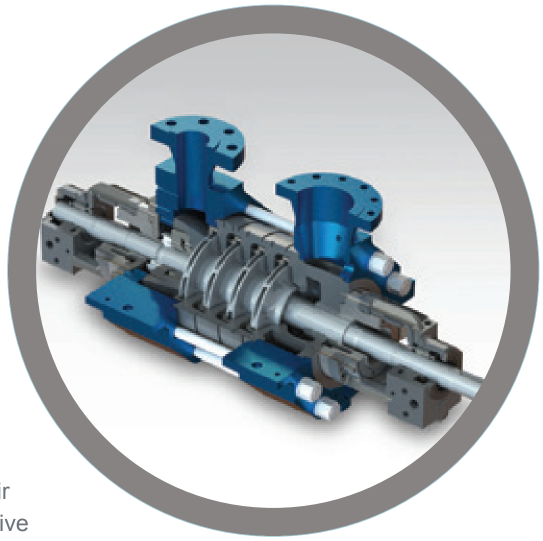

Multistage pumps are manufactured by a number of companies for high pressure medium flow applications and are critical to combined cycle plant operations.

These machines are critical but on occasion present challenges.

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Hydro®

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Results. This upgrade has significantly increased the reliability of Unit 2's circ-water system and will prevent a tower basin from overflowing if power is lost to one of the two circ-water pumps while Unit 2 is operating.

Project participants:
Nathaniel Larson, lead maintenance technician
Will Emeigh, ICE technician
Kyle Hardy, plant engineer ll

1. New Harquahala's circ-water pumps are driven by 6.9-kV motors (left)

2. Circ pumps would trip if motor-operated discharge valves were to close (right)


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Wireless technology benefits plant operations, management

Midulla Generating Station

Seminole Electric Cooperative Inc

810 MW, dual-fuel 2 x 1 combined cycle and five dual-fuel simple-cycle peakers located in Bowling Green, Fla.

Plant manager: James Woodall

Challenge. Staff faced several challenges at Midulla, including these:

- Integrating digital technologies at the legacy powerplant to improve its operation and management.
- Concerns with vibrations in a pump that could lead to outages.
- Upgrading the quality of operational data received from heat-recovery steam generators. Although equipped with critical instrumentation to support safe operation of the plant and to monitor performance, HRSG data relating to degraded flow, potentially associated with tube fouling, is not a standard data feed to the control room.

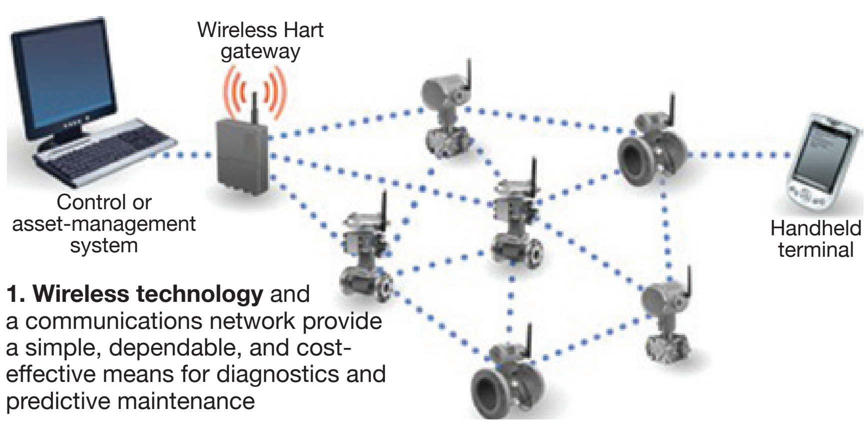
These challenges created a need to establish a complementary network for gathering important data from balance-of-plant (BOP) equipment and make it available to the control room and plant personnel for evaluation and early diagnosis of potential issues.

Solution. Plant partnered with Siemens Energy to use state-of-the-art wireless technology for improving plant operations and management. In close collaboration with Midulla maintenance management, the OEM identified key areas where additional data streams would allow plant personnel to evaluate and proactively troubleshoot operational anomalies in BOP equipment. After thorough evaluation of wireless sensor technologies, and development of a reliable network for data transmission and its integration with the site's SPPA-T3000 control system, the solution was dispatched and verified by site operating personnel.

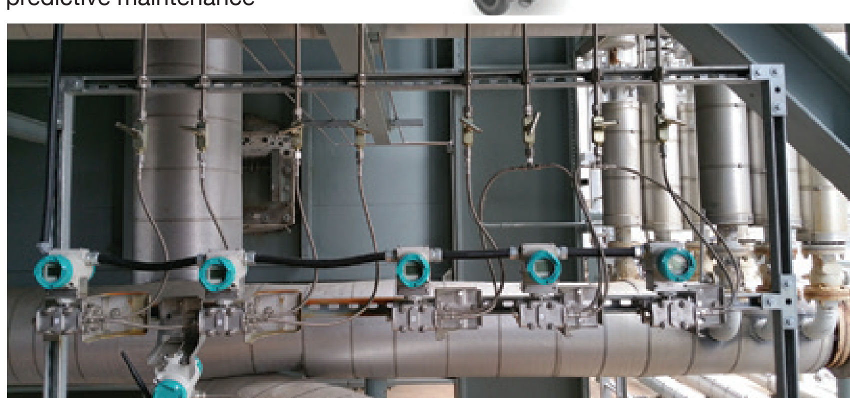
Siemens' system uses wireless technology and a communications network (Fig 1) to provide a simple, dependable, and cost-effective means for diagnostics and predictive maintenance. Wireless sensors allow Midulla to capture the measurements needed for equipment analysis. These data are transmitted through an access point (a/k/a "gateway"), and on to the control room, as well as to the Siemens Power Diagnostics® Services facility in Orlando. Last offers an avenue for Siemens to assist in troubleshooting problematic readings.

Results. The wireless solution provided the capability to monitor both standard and non-standard measurements for broadest applicability. For example, to address a recurring site nuisance issue, vibration sensors were placed on the boiler feed pump to assess changes in local vibration that could provide insight for future maintenance planning.

Another application, using wireless differential-pressure transmitters, allows Midulla to gather data regarding HRSG performance and degradation over time. This information is critical to understanding the overall plant performance and offers insight for management to scope out upcoming maintenance activities. Also, it enables early identification of



1. Wireless technology and a communications network provide a simple, dependable, and cost-effective means for diagnostics and predictive maintenance



2. Sensors can be moved to whatever piece of equipment must be monitored

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3. Solar panel keeps batteries powering wireless instruments charged

potentially time consuming and costly equipment issues.

Another valuable aspect of Midulla's wireless system is the ability to move sensors to whatever equipment might need monitoring, streaming important data to plant personnel for data-driven decisions. The technology has exponential growth capabilities, with the possibility of expanding the number of sensors used to monitor the overall performance of the plant instead of just one piece of equipment at a time (Fig 2).

In addition to creating a valuable stream of actionable data, Siemens Wireless Technology made use of a renewable energy source to power the system. A solar panel was installed on the site next to the pressure transducer's junction box. The solar panel maintains the two 24-V batteries that power the transmitters (Fig 3).

In sum, wireless technology has proven to be a secure, reliable, and simple solution, one providing valuable benefits compared with wired counterparts. Beyond ease-of-use, it allows for the expansion of usable data streams without the need to install and maintain permanent instrumentation on the vast array of BOP equipment. It also increases access to remote areas and is adaptable for use in many different situations. Above all, it helps prevent unplanned outages and maintenance-cost overruns.

Project participants:

Thomas Holland, maintenance manager
Jason Hicks, shift supervisor
Sean Colley, maintenance supervisor
James Woodall, plant manager
Bill Conley, operations manager

Dogwood

Plant infrastructure upgrade streamlines outages

Dogwood Energy Facility

Owned by Dogwood Energy, City of Independence, MJMEUC, The Kansas Power Pool, The Unified Government of Wyandotte County

Operated by NAES Corp

650-MW, gas-fired, 2 × 1 combined cycle located in Pleasant Hill, Mo

Plant manager: Steve Hilger

Challenge. Many powerplants find it necessary to bring in rental generators outage after outage to ensure that all the work gets done. They pay a lot to rent light stands with built-in generators, so the work can continue through the night; plus, welding machines with built-in generators placed strategically throughout the plant. With this equipment comes the additional cost of monitoring, maintaining, repairing, and fueling it.

This need arose at Dogwood in fall 2016, when staff faced the largest outage to date in the plant's 15 years of operation. Dogwood previously had sustained two major gas-turbine outages in 2009, along with outages on the LP steam turbine and the ST generator. In 2014, we had to rewind one of the GT generators, and make piping and valve repairs that required postweld heat treatment (PWHT) support.

Staff had to get creative, running power from spare breakers to some of the equipment and powering the rest with rental generators. This required the full attention of our two-man electrical crew and several contract electricians to configure the power supply and cabling to various jobs.

A large chunk of our budget went for a generator that was brought in on a flatbed 18-wheeler to run the air conditioning unit and desiccant dryer (Fig 1). Refueling this behemoth required outside support from a local fuel co-op,

1. Rental generator gobbles up site space and requires ongoing support by plant staff for refueling, etc

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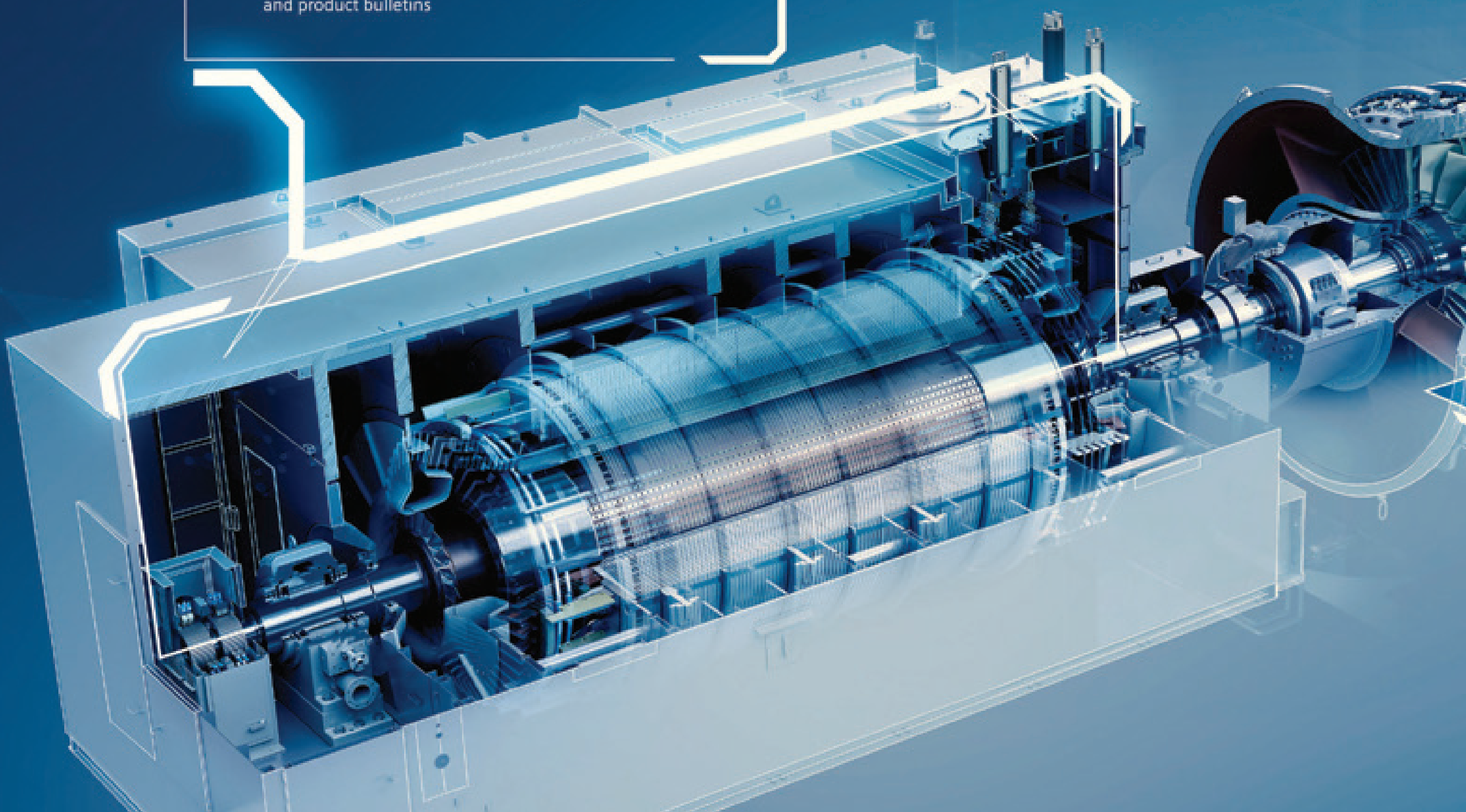
- Manways and outer air seal removal
- Remove/inspect/replace bearings, seals, blowers and coolers
- Removal of generator rotor using Siemens advanced tooling
- Other Siemens or Customer defined scopes such as service and product bulletins

Combustor Inspection

- Remove/inspect/replace all combustor components
- Borescope inspect via accessible inspection ports
- Visually inspect inlet and exhaust cylinder



Outage Customization

Siemens offers combustion inspections, hot gas path inspections as well as major and minor inspections. As the OEM, Siemens can assemble and disassemble your engine to design specifications.
Siemens can also customize any outage scope to meet your needs.

2. Dave Zalfen and Mike O'Reilly, were responsible for power-pack design and fabrication and power-supply and transformer additions

with the attendant safety concerns of transporting and offloading highly flammable fuels.

Following this outage in 2016, we were scheduled for another generator rewind, this time on our second unit. We also needed to perform a hot-gas-path inspection on the same unit, as well as a full-train steam-turbine outage (HP, IP, LP, generator, and exciter) plus several weld jobs and some grinding, cutting, and heat treatment. All of these tasks required auxiliary electrical service support.

Solution. Rather than continue paying local rental shops for use of their generators, we decided to upgrade our electrical infrastructure, which had often required supplemental power even for small outages. Our primary source for auxiliary power was existing power packs that would plug into a 480-V, 60-amp welding receptacle, of which we had 10 that had been installed as original equipment throughout the plant (Fig 2). These power packs included 18 120-V circuits, two 480-V circuits, and a 480-V/120-V stepdown transformer.

The upgrade plan was to install another 10 480-V, 60-amp weld receptacles throughout the plant, along with a 500-kVA transformer and associated relaying. We also included two additional power packs with 480-V/120-V stepdown transformers feeding two 480-V breakers, eight 120-V receptacles, and two 208-V receptacles.

In sum, Dogwood made the following substantial permanent power supply upgrades in 2016:

- Three additional 480-V welding receptacles in the steam-turbine area.
- One additional welding receptacle at each of the two gas-turbine packages.
- One additional welding receptacle on the upper catwalk area near several large valves that potentially require field machining in addition to welding and heat induction equipment.
- One additional welding receptacle on the east side of each HRSG, which previously had no power support.
- An additional 500-kVA, 4160-V/480-V oil-filled transformer that would power a panel with a 250-amp circuit, a 200-amp circuit, three 100-amp circuits, two 60-amp circuits, and two 30-amp circuits. Two welding receptacles would be fed out of this panel as well, and we added a relay at the 4160-V panel for transformer protection.

This ended up being a fairly large project with a lot of moving parts, especially the addition of the oil-filled transformer. The transformer required excavation for an underground conduit and concrete containment as well as the consideration of the protective relay. We had our existing infrastructure evaluated to ensure it could handle the eight additional welding receptacles and surveyed the plant overall to assess where power sources were lacking and where a likely need would occur.

Results. On project completion we noticed some obvious and immediate benefits. First and foremost, we now enjoyed plenty of power availability throughout the plant. During the fall outage, Dogwood did not have to rent a single generator for additional power support. In addition, we were able to eliminate the large flatbed generator with its substantial footprint, which not only eased our budget but freed up space for better traffic flow and for equipment needed to support other projects.

Last but not least, we no longer required plant personnel to monitor or refuel the generating equipment. This was no small issue: when we did our first generator rewind, we had to have the flatbed generator refueled almost daily, which required coordination and scheduling to refill the plant's 500-gal fuel tank every third or fourth day—including weekends. All of our needs for additional fuel support were virtually eliminated.

This was a large and expensive undertaking. We would not recommend it to a plant that foresees only small outages for the near future. However, the upgrade saved Dogwood approximately $45,000 in equipment rental, fuel and fuel surcharges, onsite electrical support, and contract electrical support for this major outage.

Eventually, almost every powerplant will have to perform major outages for combustion and steam turbines as well as generator rewinds. That could be three years down the road, possibly five, maybe even 10. But when you do your long-term planning, we suggest you factor in all of your rental generator needs and bounce those off of what your existing infrastructure can support.

You may find that reducing your immediate and future outage costs, reducing liquid-fuel costs, and the safety concerns in handling that fuel would offset the cost of an upgrade. And there's also the benefit of clearing away all of that rental equipment footprint, making for a cleaner work zone at the same time you're increasing the available power supply and trimming labor-hours.

Project participants:
Mike O'Reilly, power-pack design and fabrication
Dave Zalfen, power-supply and transformer additions
Glenn Brons, project oversight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Plant manager: Jim Murray

Chlorinator conversion from bleach

Challenge. Government limits on Orlando Cogen's wastewater discharge permit for sodium was reduced by half. Discharge sodium levels exceeded the new limits; sodium hypochlorite was added continuously for biological control in the cooling tower, which relies on blowdown to the city sewer for conductivity control.

To meet the new requirements, batch addition of sodium hypochlorite was implemented on a twice-per-day regimen. This barely got the facility's sodium discharge level under the new permit limit.

Plus, biological growth in the cooling tower could not be controlled with the new program. In only weeks, biological growth formed on the cooling-tower structure and fouled packing and fill material (Fig 1). Besides the obvious biological growth, bulk handling of liquid sodium hypochlorite was required monthly, the hazards of which required PPE of chemical suits, goggles, face shields, gloves, and boots.

The highly corrosive characteristics of sodium hypochlorite also caused numerous process equipment failures in piping, valves, and the injection pump.

Solution. Industrial-grade calcium hypochlorite in tablet form, which is used in the food-processing industry, was used in a chlorinator vessel along with a solenoid valve wired to an ORP controller. The latter opened and closed the solenoid valve, based on control-band set points for free chlorine level, allowing a slip stream of tower water to flow through the chlorinator dissolving the tablets. This process allowed continuous control.

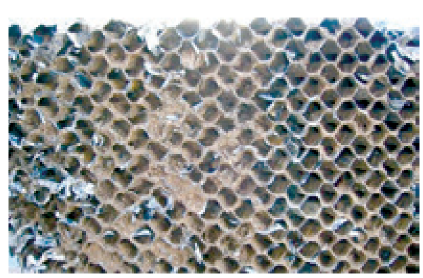
Results. A 40% to 50% reduction in sodium discharged was achieved using the calcium hypochlorite tablets. Complete biological control throughout the cooling tower was achieved within a few weeks (Fig 2).

The chlorinator process consists of only one moving part, the solenoid valve. The maintenance on this process has been reduced to practically zero with the exception of an annual cleaning of the chlorinator vessel, which takes only about five minutes to do.

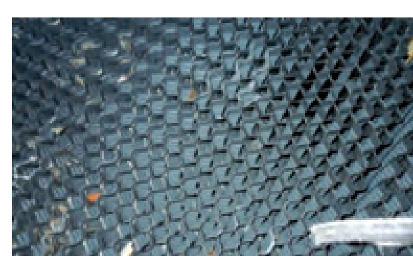
The cost of calcium hypochlorite tablets to maintain proper chlorine levels in the tower water is less than the cost of bulk sodium hypochlorite.

Finally, onsite handling and storage of liquid sodium hypochlorite is no longer required. Safe handling of calcium hypochlorite requires only gloves when filling the chlorinator daily.

Project participant: James Chaney



1. Biological growth while using batch addition of sodium hypochlorite



2. Biological growth after switching to calcium hypochlorite on demand

Man down: Lone worker emergency response

Challenge. Minimize risk exposure, improve monitoring capability, and reduce response time for single-operator shift operations. As with many facilities, the operating staff is composed of an ageing workforce with associated limitations and concerns, further amplifying the need for these improvements.

Solution. *Risk:* Plant policies were established, restricting potentially hazardous evolutions to normal working hours when support staff is available for assistance. Operator rounds were evaluated, readings in remote locations were satisfied using alternative methods—such as video—or eliminated.

Monitoring: The original man-down system consisted of a traditional check-in system with limited versatility, potentially poor response time, and was considered a nuisance by operators. A new system from Blackline Safety Corp was implemented. It consists of Loner monitoring devices (Fig 3), ANThill locator beacons (Fig 4), and a remote monitoring service.

The versatile Loner devices provide four modes of initiation: manual, fall detection, no motion, and silent alert. Tracking of Loner location is accomplished through GPS when outside and through ANThill locator beacons

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3. Loner location is identified via GPS

4. ANTHill locator beacons are installed at critical locations in the plant

5. PPE specified for this location is ready for use

staged in each building when inside.

Response: Loner initiation results in immediate direct voice communications with the Blackline Safety monitoring service. The monitoring service follows a user defined escalation protocol to attempt resolution prior to requesting emergency response, if possible. If emergency response is requested, the monitoring service provides responders with operator location and facility access information.

Results. No actual emergencies have occurred since the system was placed in service. A few accidental initiations have resulted in immediate response and resolution at the plant level. The system is tested quarterly and has performed flawlessly.

Project participant: Tim George

Arc-flash procedures made easy

Challenge. Implement an easy-to-understand arc-flash safety program and improve compliance with the requirements of OSHA 1910.269, "Arc Flash Safety for Utilities," and NFPA 70E, "Standard for Electrical Safety in the Workplace."

Solution. *Training and qualification*: All operators were trained on the basic requirements of electrical safety and completed arc-flash specific training through NFPA 70E online courses. All routine electrical operations were identified, and detailed procedures were created for each. These procedures establish the standard requirements for the performance of each task and eliminate the need for additional assessment and permitting.

Operator proficiency was established for each of the procedures. All operators are now qualified to perform only those evolutions, and only if no abnormal conditions exist. Any evolution outside of their qualification boundaries requires additional evaluation and permitting.

Arc-flash assessment: Safety Tracker software from EasyPower was selected based on its flexibility and ease of use. Many short-circuit analysis programs provide the end user with only fixed data tables from which information is obtained to create labeling and permitting.

Safety Tracker provides a fully customizable one-line diagram allowing user manipulation of electrical plant configuration, allowing for real-condition arc-flash data. Bus- and task-specific energized electrical work permits with associated shock and arc-flash hazard information can be generated, as well as planning/briefing worksheets and custom arc-flash labeling.

Arc-flash PPE: Each power distribution center is staged with the latest lightweight arc flash gear available, with multiple sizes to support all operators. The arc-flash protection rating of staged PPE is sufficient to cover all routine electrical operations in that respective power distribution center (Fig 5).

Results. The training and qualification program has defined the evolutions that operators can perform, eliminating the permit decision-making process. The Safety Tracker software's flexibility has enabled some evolutions to be performed under reduced arc-flash hazard conditions and significantly improved permitting and labeling. Staging the PPE has made it as convenient as possible for the operators to don proper arc-flash protection for the evolution and minimized the need to interpret labels and make PPE determinations.

Project participant: Tim George

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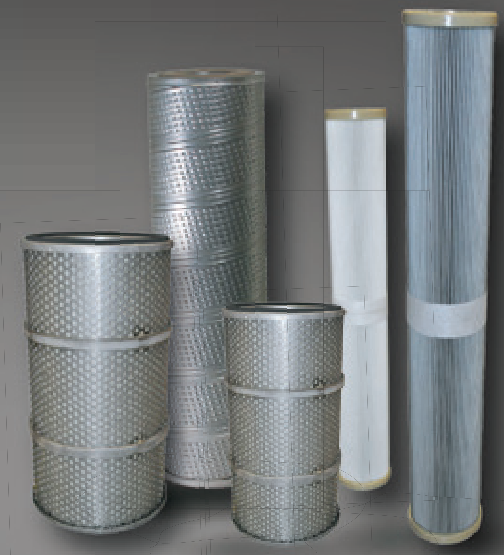

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Checklist for success: NV Energy commissions seven turbine DCSs in seven weeks

Commissioning seven gas-turbine (GT) control systems in seven weeks would probably be taxing under the best of conditions. In NV Energy's case, there were some extenuating circumstances.

First, the seven systems are located at two generating facilities acquired by the utility in 2014. Second, it is challenging to test a retrofit, due to air-permit emission limits. Third, NV Energy, like most utilities today, has limited central engineering staff for projects like this. Finally, the original estimates for the projects were established by the due-diligence team, but had to be carried out by engineering and operations. No field instrumentation was included in the scopes.

As background, three of the GTs, gas-fired (no backup fuel) GE 7EA peakers located at Sun Peak Generating Station (SPGS), have water injection for NO_x control and minimum balance-of-plant (BOP) systems.

The other four engines are at Las Vegas Generating Station (LVGS), which has three combined cycles powered by LM6000s equipped with water injection for NO_x control and SPRINT compressor inlet water spray for power augmentation. Two of the combined cycles are in a 2 × 1 arrangement (installed in 2003), one is a 1 × 1 (installed in 1994). The latter was not included in the controls upgrade project.

The controls retrofit at SPGS was justified on the basis of adding remote operation; the LVGS retrofit was justified to improve and automate transitions in and out of SPRINT mode. Both projects were commissioned in seven weeks during October and November 2016, with no third-party owner's engineer in the mix.

An interesting wrinkle, important to understanding how the projects unfolded, is that SPGS went first in the schedule. Because it required a Class A Nevada contractor's license by NV Energy's procurement group, the electrical contractor was lead, with Emerson, the DCS supplier, as sub.

Due to a less restrictive project scope for LVGS, this requirement was relaxed such that a Nevada Class C contractor could lead, which allowed the DCS vendor to be lead, and the electrical contractor as sub. Nevertheless, this led to two separate engineering specifications for each plant.

As reported by Clint Vanderford at the Ovation Users Group Conference in July 2017 and during a follow-up call with CCJ editors, the experience offers valuable lessons—from the acquisitions phase through commissioning new equipment—for others undertaking such projects.

In reviewing the challenges explained below, it's important to note that each plant had a different owner and both were IPPs, with design features that may not be considered "utility-grade." Also, some of these are typical "gotchas" which occur with every project of this type and magnitude, but still suggest wise cautions for others contemplating similar work.

Carefully review all instrumentation relevant to the retrofit. Many project issues stemmed from a lack of instrumentation expertise on the acquisition due-diligence team which led to the controls retrofit project team being unaware of important instrumentation issues. All of the gas turbines here feature wet NO_x control (water injection). Some of the instrumentation at SPGS is 1980s-vintage. LVGS had LM6000s equipped with newer instrumentation, but valve positioners in the Woodward control system posed problems. Plants often "live" with marginal instrumentation. The larger point here is that existing instruments will exhibit varying degrees of compatibility with a state-of-the-art DCS.

Clarify each participating group's capabilities and experience. Each facility's contract was managed differently. At SPGS, a local electrical contractor licensed in Nevada acted as the lead EPC contractor with Emerson as a subcontractor. At LVGS, Emerson was lead contractor with Dynalectric Nevada as sub.

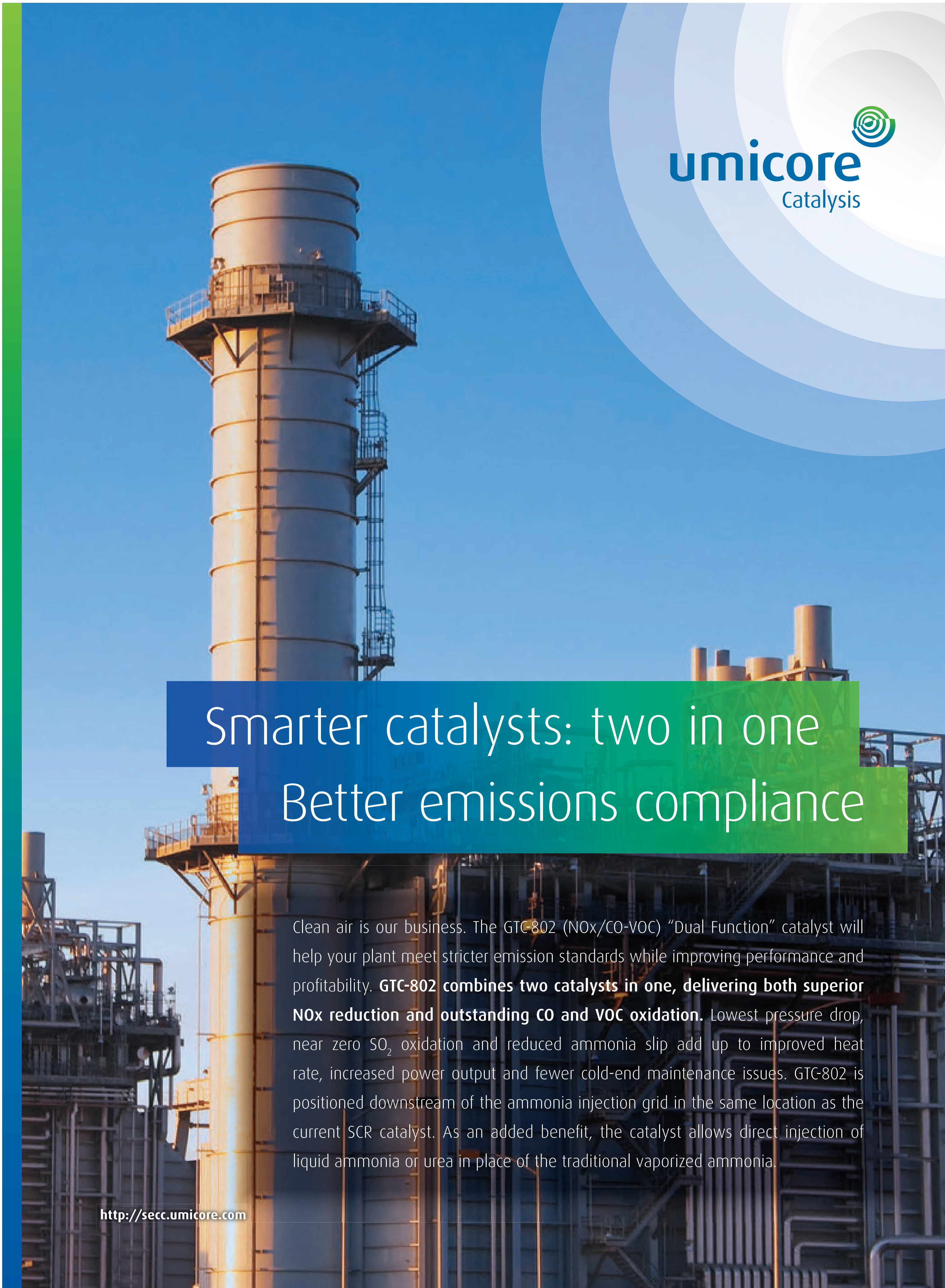
Lesson learned: The DCS supplier is a better EPC than an electrical contractor, in part because of the inherent understanding of the instrumentation. On the other hand, Emerson had little experience retrofitting LM6000 machines with Ovation; this inexperience surfaced in the areas of cabinet layouts and construction and diagnosing wiring circuits. Substantial new wiring had to be pulled to replace cabinets located at the turbine housing (the gas-turbine OEM's design basis) to cabinets located outside the control room (the DCS vendor's design basis).

Pay attention to the soft/hard interface. Vanderford noted that Emerson did a really good job delivering the "soft" product—that is, writing the logic and building the graphics. Wiring the existing plant components to the new DCS equipment was not so straightforward.

At LVGS, there was no one who could actually install the new gear, so it had to be hired out. A third-party contractor had to make sure everything was properly wired. The project team found numerous instances of "duct tape" solutions with the existing equipment which had to be remedied to hook up the new controls.

At SPGS, the ABB Bailey BOP controls and the GE gas-turbine controls were hard-wired—that is, no bus or data highway. "It was like peeling an onion," Vanderford said, "it took a few iterations to achieve our objective of having minimum hard-wired stuff." However, the protective circuits are still hard-wired. The project team also found numerous instances of electrical changes not properly documented.

Focus on the graphics. What the operators see on their screens helps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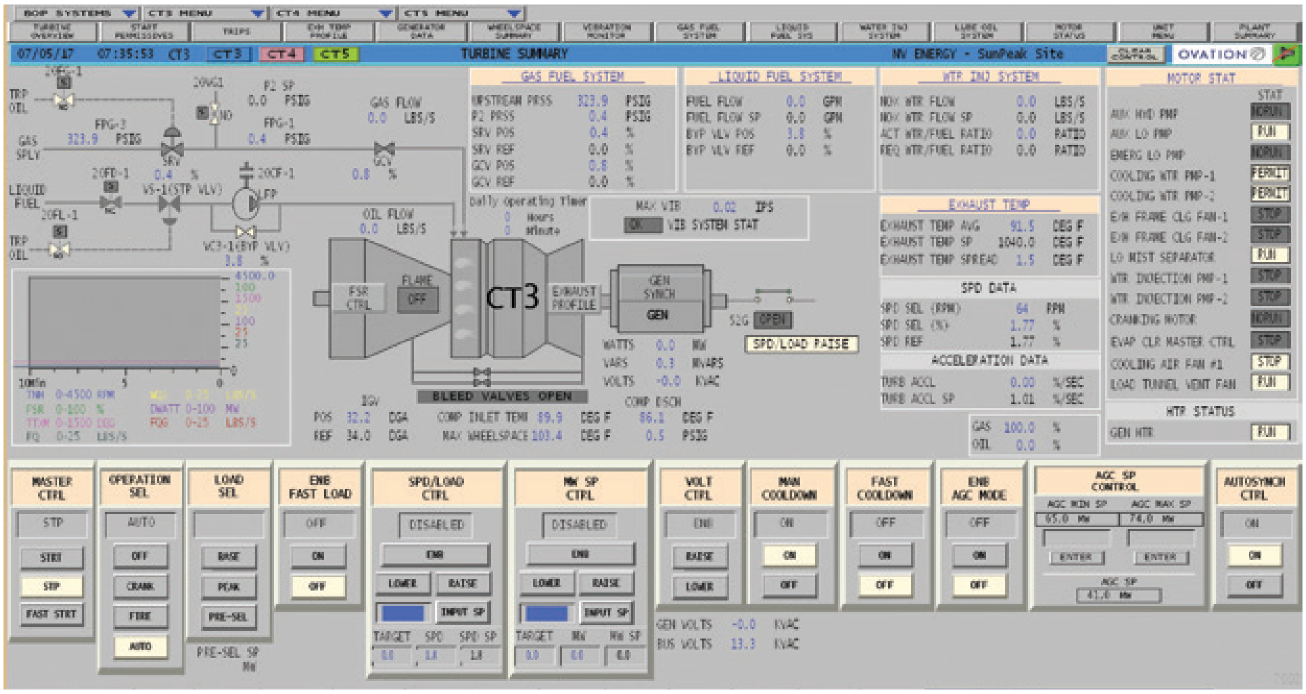
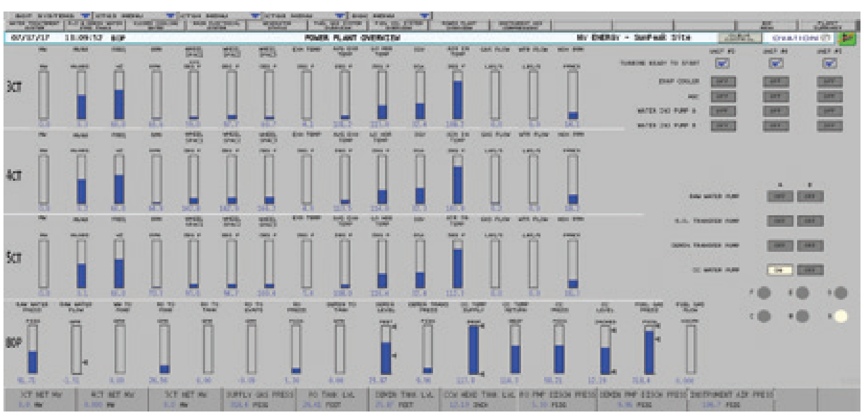


Creating high-performance graphics for operators (below) from standard GT graphics packages (above) was the subject of much "back and forth" between NV Energy project engineers and the DCS vendor



determine how well they can run the equipment. Emerson's Ovation team includes GT specialists, but they are typically not plant operators, and they build and deliver "standard" graphics packages. Those who specify and bid projects like these have to incorporate flexibility to modify the graphics so they work for GT plant operators, not GT engineers.

Vanderford said the Ovation "standard" graphics were crowded (figure) and not well organized, and that boilers "don't exist in the GT controls world. Many discussions were required with Emerson's Clifton Park GT specialists," he added.

Know your air permits *before* starting the project. It is challenging to test a retrofit like this because air-quality permit limits cannot be violated. Not all of the post-installation testing that was required at SPGS would fit within the air-permit emission limitations. As the regulatory agency does not issue variances, there was no way around this limitation. This made it difficult to commission the new turbine governor.

This also necessitated postponing the voltage-regulator replacement, because it requires one hour of operation at full speed and no load, even though the existing one is old and not easily maintained (though it is still deemed reliable). NV Energy is pursuing the permitting of a limited amount of operation at higher permit limits for the purposes of testing and tuning, which will allow the new voltage regulator to be commissioned.

Check out motor and other critical component specifications prior to testing. NV Energy experienced a starting-motor failure during the commissioning. An underrated motor had been installed before the project as a replacement, and it ended up running longer than it was designed for as part of the commissioning. The relays in the DCS were programmed to protect the load of the old motor, not the new one. An auxiliary lube-oil-pump motor also failed but Vanderford chalked this up to age: "Its time had come."

Trust, but be in a position to verify. Because of the lack of central engineering resources and minimum plant staff, NV Energy had to place a great deal of trust in its contractors. For example, Vanderford notes, "we lacked experience in governor logic, and had to trust the DCS vendor, while holding some money back until verification that the controls would work as designed."

The electrical contractor was more of a "generalist," though with abundant industrial facility experience, and required "coaching" by NV experts. Few on the plant staff had the requisite knowledge of the equipment to carry out a project like this.

In the end, says Vanderford, success in construction relied heavily on good will and good working relationships among the team members. Each project was run by the plant, although up until 2016, such projects would have been handled by a central project management group.

Overall, Vanderford reports, there were no major failures and no major delays and the transition to normal operations went well. That's quite an outcome when retrofitting seven gas turbines in seven weeks across two facilities with substantially different systems, equipment vintages, and former owner/operators. CCJ

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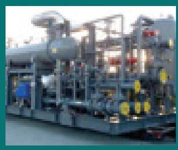
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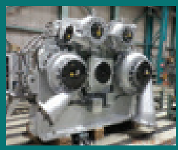
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Ravenous ruminants rid reservoirs of renegade reeds

By **Colleen Dolan** and **Regina Chan,** New Athens Generating Co

Athens Generating Plant is a grassroots 1080-MW combined-cycle facility located 30 miles south of Albany in Athens, NY. Powered by three Siemens 501G machines, the plant is owned by Talen Energy, Woodlands, Tex, and operated by NAES Corp, Issaquah, Wash.

Construction activities began in 2000 and included two storm-water basins designed to safely capture and release natural and facility discharge into federally protected wetlands. The man-made ponds are monitored by the New York State Pollutant Discharge Elimination System Permit Program.

Since commissioning in 2004, the ponds, located in opposite corners of the property and designated the northeast and southeast ponds, have become overrun with vegetation, mainly cattails and sumacs. Such vegetation is often found at power-generation facilities, especially those surrounded by woods and wetlands.

Storm-water ponds become inefficient when overcome with vegetation. And when pond berms attract vegetation (other than grass), root systems can undermine the berms causing leaks. At Athens, the cattails also attracted muskrats, which began making holes in the berms. Vegetation control therefore became a critical part of facility maintenance.

Unobstructed visibility of the site's perimeter also benefits plant security.

Storm water

Proper pond maintenance is critical for both operation and environmental conservation. Generally, storm water refers to runoff that does not soak into the ground, and can travel into waterways. In the case of Athens, that eventually leads to the Hudson River, north of Manhattan.

Storm-water runoff collects pollutants and debris as it travels, enabling concentrations of materials that can cause damage to lakes, rivers, wetlands, and other water bodies. Thus it can have negative impacts on animal and plant life, plus sources of potable water, and other things as well.

1. Cattails soon overwhelmed the Athens storm-water ponds

Because containment and controlled discharge are part of Athens' state permit program, vegetation must be controlled.

Pond areas

Cattails are aquatic perennial plants found exclusively in the Northern Hemisphere and are known as obligate wetland species. They are dominant in wetland environments, overpowering most competition with their dense canopy. Both broad-leaf and narrow-leaf species (Fig 1) overwhelmed the Athens ponds.

Three species of sumacs (Staghorn, Smooth and Poison) also appeared in and around the ponds (Fig 2). These shrubs and small trees produce flowers with dense pinnacles and fruit. Sumacs can reach a height of 30 ft.

The northeast pond is designed to collect and release water from natural sources and from the Athens facility. When vegetation became an apparent problem, the pond's discharge pipe was closed for long periods in an attempt to raise the water level where cattail growth would not be induced.

The area also was brush-hogged. These two actions significantly reduced the need for vegetation removal and maintenance.

But the pond berm and surrounding area soon became an alternative growth area, and uncontrolled sprouting became a new concern. Extensive mowing is the current viable solution.

The southeast pond (Fig 3) also is designed to carry, collect, and release, but the facility has not yet been required to open its discharge pipe. Water collected in this pond is from rain and occasional release from transformer containments. Therefore, the level normally is low, providing an ideal environment for vegetation growth within the pond. Both cattails and sumac have flourished and have invaded the berms and surrounding areas.

Brush hogging, extensive mowing and manual labor have not decreased the problems. Some cleanup activities actually have increased the progression of these plants.

Actions and alternatives

Biocides and herbicides were never an option. Alternatives were discussed with the New York State Department of Environmental Conservation, concluding that mechanical removal would be the most appropriate. But New Athens had attempted mechanical means since 2011 and these had proven neither economic nor efficient. The vegetation would return.

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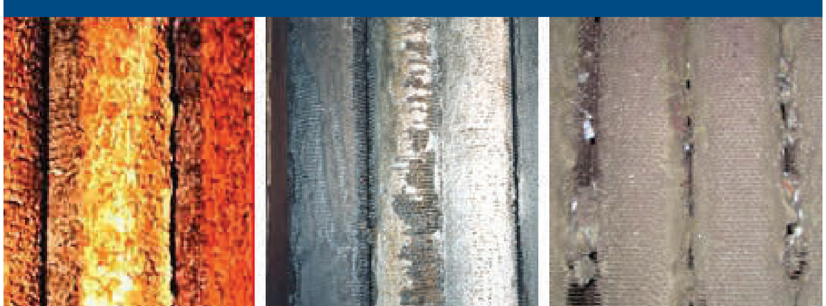

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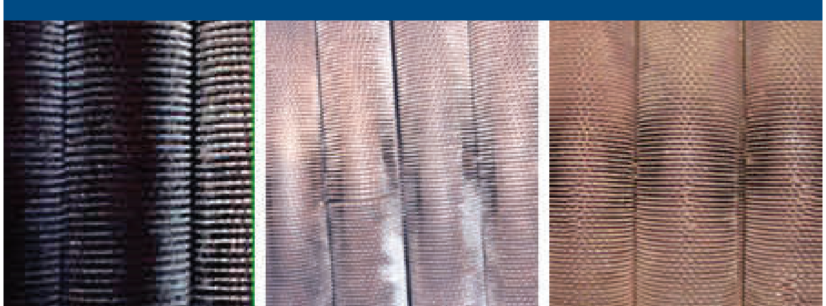

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Back to nature

Sometimes the best solutions are relatively simple and, in this case, local.

Athens personnel contacted a local farmer who raises goats. They are herbivores, naturally clearing land with their insatiable appetites, and capability to ingest a wide variety of plants. Their natural craving includes cattails and sumac. For the more tree-like sumac species, goats will eat the bark or use it to clean their horns, in addition to eating the leaves. This prevents new shoots from growing.

After surveying the southeast pond area, the farmer was willing to locate a small herd of 10 goats in a fenced area for eight weeks (Fig 4). He would visit daily to bring water, check animal health, and oversee progress. This became a trial run to determine whether or not the goats would be comfortable and willing to feed on the overgrowing vegetation.

Goats were placed in four different areas of the pond (refer back to Fig 3) throughout the eight weeks to test their appetites and adjustment to the environment. Photographs were taken at a specified hour each morning.

Area 1. The southern area of the south pond is a steep hill that meets the Conrail Railroad tracks east of the Athens facility. This zone is filled with sumac and has grown into a miniature forest. The view of the tracks (and security perimeter) is obscured by the dense canopy of leaves and thick branches. This area was chosen the first test because of its abundance of sumac (Fig 5).

Within 48 hours, the goats had made significant progress, eating away at the sumac leaves and cleaning their horns on the bark. Within 10 days, the view of the railway was significantly improved. Approximately half of the trees were stripped bare as the goats targeted the staghorn and smooth sumac. They also ate the grass, flowers, and weeds.

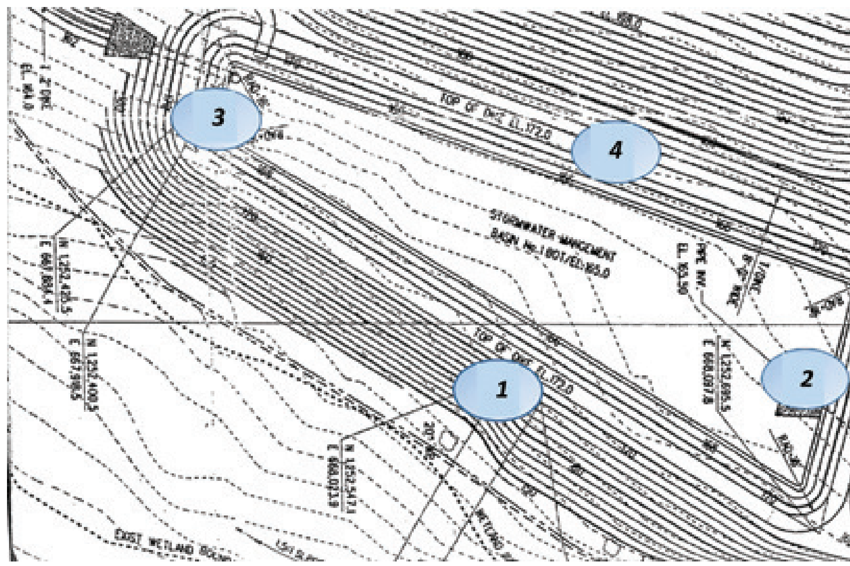
The goats concentrated on the steep hill. The untouched vegetation was either plants that they could not ingest, were too high to eat, were poison sumac, or were staghorn containing white flowers (young sumac getting ready to bloom).

Area 2. The goats were moved to the second zone after 10 days. This was the pond area containing cattails and surrounded by sumacs and other vegetation, and was the area of most concern to the facility (pond discharge pipe).

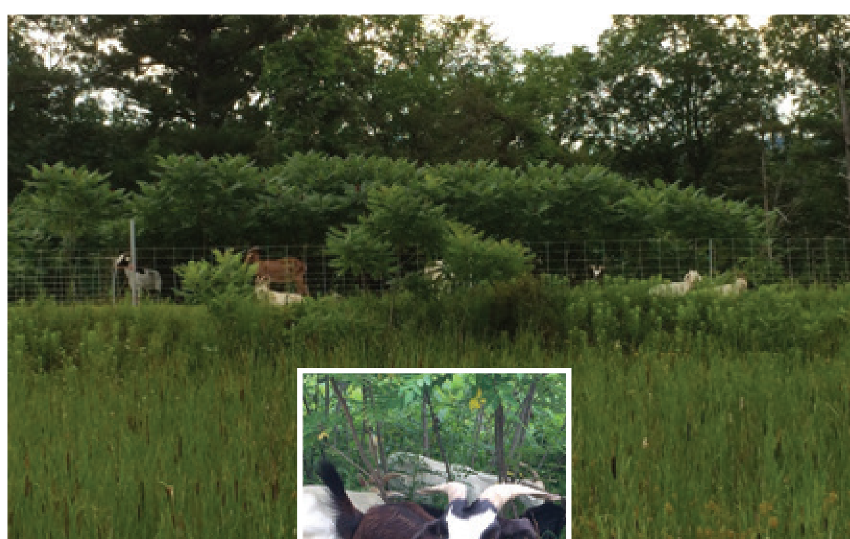
However, because of poor weather and standing water in the pond, the goats did not venture into the base but instead only grazed on the sides, eating the sumac trees. Their sensitivity to water overruled their preference for cattails, reducing their overall impact. They ate approximately 35% of the area, consuming leaves and breaking down barks, impeding future growth.

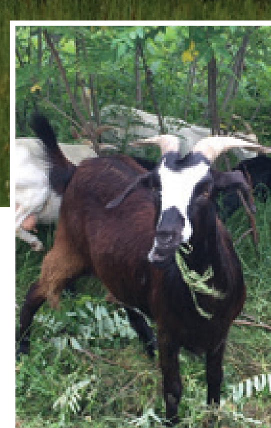
Area 3. After 14 days in Area 2, the goats were moved to a zone densely

2. Sumacs appeared in and around the plant's ponds



3. Goat-trial areas were set around the southeast pond





4. The herd and *the boss*

5. Looking toward the perimeter fence

6. Goat-trial results after two weeks in Area 2

populated with shrubs and weeds on the hill and with staghorn and smooth sumac at the base. This was the smallest test area, bordering a larger natural habitat. Thick vegetation made it difficult to monitor progress. The goats cleaned approximately 25% of the vegetation, primarily on the hill. Rain accumulated on the ground floor where other sumac resided, and the goats were soon moved to the next area.

Area 4. The final test zone was the north region of the southeast pond. This area is also a hill that meets with an adjacent fuel oil tank. It is not filled with cattails but instead consists of tall sumacs, shrubs, bushes, and common weeds. The goats could graze and then rest under the tall trees during hot days.

Approximately 40% of the area was cleared by the feeding. Another 10% was eliminated through sun exposure as the goats stripped the bark and ate the roots. Their preference for sumac reduced any significant impact on other shrubs; they would break the shrub leaves and pull on branches but would not consume them. The farmer became concerned for their nutrition and they only remained for one week.

Results

This trial seemed to benefit the facility, the goats, and the farmer.

For the plant, approximately 40% of the overall vegetation in the test pond area was cleared (Fig 6). It was environmentally sound; the vegetation was reduced and nutrients were restored back to the ground. It was also economical, providing a sensible program with positive results.

For the farmer, the goats were well fed and grew quickly.

Roadblocks were identifiable. Water in Areas 2 and 3 limited the goat herd's potential to clear away cattails. Dislike for young, tall staghorn sumac in Areas 1 and 4 limited overall sumac clearing. But the trial provided first-hand experience and useful data for future trials and programs. Many roadblocks (water accumulation, for example) can be reduced with early planning.

Goat trials will resume in summer 2018 at other plant areas. CCJ

Group-sponsored development projects share results, reduce costs

European Technology Development Ltd conducts multi-client projects to address concerns and challenges within the international electric-power industry. Known as ETD Consulting, the UK company's projects are aimed mainly at developing new tools, technologies, and methodologies for powerplant inspection, integrity, and life assessment/extension; and improvements to materials, welding, and design.

Since its formation 20 years ago, ETD also has been providing independent technical consulting and onsite services, products, and specialized training to the power and process industries using both existing techniques and those developed through its group-sponsored projects (GSPs).

Collaboration with the international power industry is key to developing new tools and cutting costs while achieving useful scientific results. This approach pools both financial and technical resources, technical know-how, and lessons-learned databases. Among the company's current group-sponsored projects of interest to CCJ readers are these:

- Aberrant P91 long-term creep rupture data collection, inspection, and repair.
- Crack assessments in boilers/HRSGs and turbines.

ETD concentrates heavily on the integrity and life assessment of plant systems and components based on disciplines of mechanical engineering, materials science and metallurgy, and inspection and maintenance in high-temperature applications—somewhat similar to what US-based EPRI and Structural Integrity Associates Inc do as well. It specializes in probabilistic crack and life assessments, which require large databases.

According to Dr Ahmed Shibli, CEO, "ETD has expertise in plant services and technical consulting backed by R&D conducted with manufacturers, plant operators, service providers, and researchers from around the world. We are in an ideal position to conduct such projects for industry sponsors, and bring together plant experience from best-run plants in Europe, Japan, US, Canada, Australia, and elsewhere." A few GSP examples follow.

1. Ferrite phase found in find-grained heat-affected zone/inter-critical HAZ in an aberrant P91 pipe

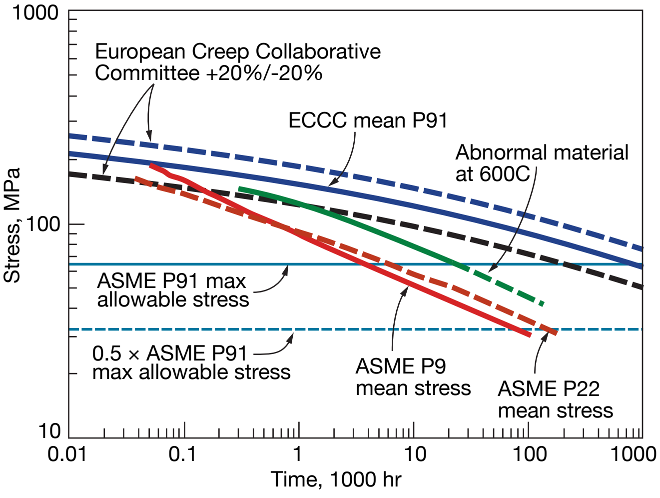
Creep rupture strength of P91 materials and welds, a six-year project, is generating long-term creep rupture data to help plant operators establish safe operating lives of aberrant or abnormal P91 base- and weld-metal microstructures (Fig 1) often found in powerplants and HRSGs. The aberrant materials and weldments arise when heat treatment during either steel production or component fabrication is not conducted to the precise requirements for P91—a high-chrome martensitic steel. With incorrect microstructure, creep rupture strength is reduced, leading to early failure.

Given the absence today of long-term rupture strength data for aberrant microstructures, some plant owners and operators are not sure how to deal with such components and often treat them as either P22 or P9 steels, sometimes unnecessarily condemning critical and costly components too early, at great expense to owner/operators (Fig 2).

Within this project, tests are being conducted on 15 aberrant microstructures at durations of up to 30,000 hours. Current sponsors include organizations from Europe and Japan.

As background, ETD plant experience includes NDT of boiler P91 welds at the 460-MW Quezon Power Plant in the Philippines; P91 work for EdF in France, Inpex in Australia, Malakoff and TNB in Malaysia; plus work at Uch Power Plant in Pakistan and other facilities in the Middle East, Europe, and Far East. Also significant is an ETD Grade 91 Users Group initiative for the supercritical Keephills Unit 3 in Canada.

Although not part of the original Abnormal P91 GSP scope, the work on this project also is helping to estab-



2. Cross-weld creep rupture strength of an abnormal P91 material may compare with that of ASME P9 and P91 steels at 600C

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lish new inspection regimes for both P91 and P92 components.

Inspection techniques and life assessment for P91 and P92 in-service welded components is a closely aligned GSP with a three-year duration. According to Shibli, "Welded-pipe creep tests are being performed and stopped at 30%, 50%, and 70% of estimated life to enable an assessment of new inspection techniques and study of damage development with lifetime consumption."

Inspection techniques include (1) replication, (2) hardness, (3) innovative UT, (4) boat sampling using a newly developed portable spark erosion machine, (5) portable scanning force microscopy (SFM) to detect early-life damage and the creation of 3-D creep-cavity images (Figs 3 and 4) using cavity volume for life assessment, (6) electromagnetic property measurements, and (7) AC- and DC-potential-drop techniques.

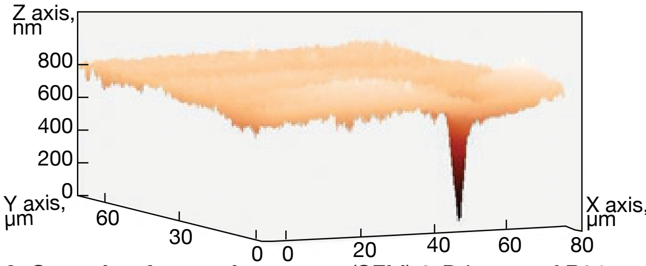
The aim of this GSP is to develop and experiment with innovative techniques that can detect and quantify creep cavitation damage in P91 and P92 steels at an early-life stage. At present this is difficult because traditional NDE techniques are inadequate for the task.

Three large P91 pressure vessels and one P92 vessel, with both butt and seam welds, are being tested under pressure and high temperature—and with end loads to obtain in-service-like Type IV failures in butt-welded pipes at a planned duration of about 10,000 to 15,000 hours.

States Shibli, "Tests have now been completed along with supporting cross-weld rupture data and finite-element analysis. Relationships between damage in the Type IV or fine-grained region of the heat-affected zone (HAZ) and the remaining life of the welded components are developed to help plant operators detect and quantify early-stage damage. This will give them time to develop repair or replacement strategies before potential and possibly abrupt failure takes place."

Participants are from the UK, US, Japan, Germany, Italy, and Belgium.

A similar project has been planned using P91 pipes containing aberrant microstructures to further demonstrate the above NDE techniques together with a few new and promising methods. This GSP will help in developing inspection strategies for components with aberrant microstructures. In addition, it will



3. Scanning force microscopy (SFM) 3-D image of P91 pipe showing the depth of a cavity

4. SFM in use on a P22 pipe at a refinery in Italy

demonstrate a Japanese-developed technique for strengthening creep-damaged pipe (Fig 5) for which ETD has the rights for further development. Existing sponsors are from the UK, US, Europe, and Japan; new sponsors are being pursued.

CrackFit is a new group-sponsored project that uses ETD's procedures and software to assess cracks in both low- and high-temperature high-pressure equipment (Fig 6). The technology presently covers 17 geometries of pressure vessels and piping components typically found in power and process plants. Steam and gas turbine geometries also are being investigated. CrackFit software significantly reduces the time required to complete assessments, in some cases reducing weeks to days.

Initial work by ETD was supported by the European Commission and leading European universities and industry; data were supplied by operating plants.

Says Shibli, "CrackFit comes with an optional crack initiation and growth database for base metal, HAZ, and welds for many materials of interest to the power and process industries. It deals with defects such as lack of fusion/penetration in welds (defects at weld toes), internal- and external-surface emerging or embedded defects in straight pipes and pipe bends, defects at stress concentrations such as sharp corners (T-pieces, nozzles), and defects in plates, among others."

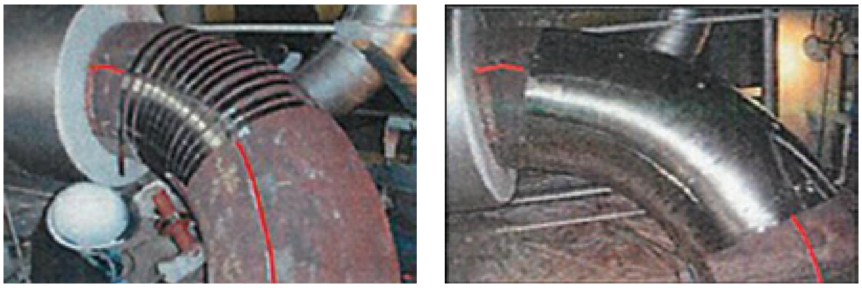
Shibli further explains that the software is "user friendly for industry engineers who would like to carry out defect assessments without having to go through the different established codes or country/in-house defect assessment practices." Procedures including BS7910 (a BSI-British Standards Code of Practice for the assessment of flaws), Nuclear Electric (UK) R5, the French nuclear code RCC-MR A16, and the European HIDA (high-temperature defect assessment procedure) are available as software options.

"The software allows for failure analysis (fast fracture, plastic collapse, and ligament rupture) and the evaluation of damage mechanisms such as creep, fatigue, and creep-fatigue interaction," he explains.

A fitness-for-service program incorporated into the software performs calculations to determine a defect's criticality in line with the assessment codes. The software carries out both deterministic and probabilistic crack assessments. Modules within the study are:

- Materials.
- Cyclic loading of powerplants.
- Sensitivity and probabilistic analysis.

Weldlife, a five-year GSP launching in early 2018, will investigate



5. Pipe strengthening of creep-damaged material

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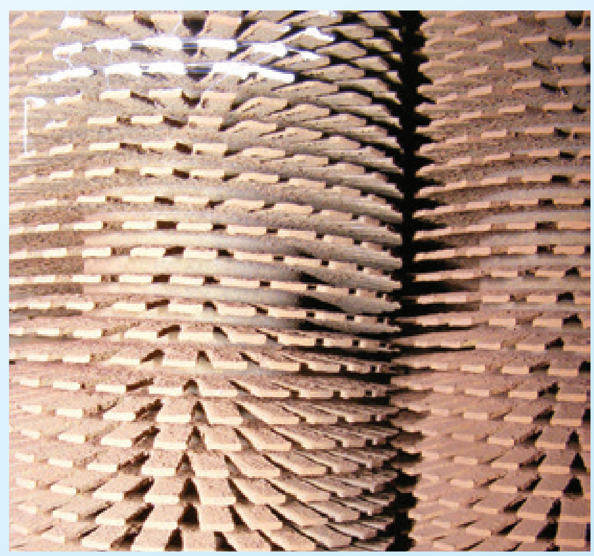

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- Each year in August:
  Three separate conferences… three different agendas
  Same dates, same location, shared meals and shared vendor fair
  - Combined Cycle Users Group – www.ccusers.org
  - Generator Users Group – www.genusers.org
  - Steam Turbine Users Group – www.stusers.org
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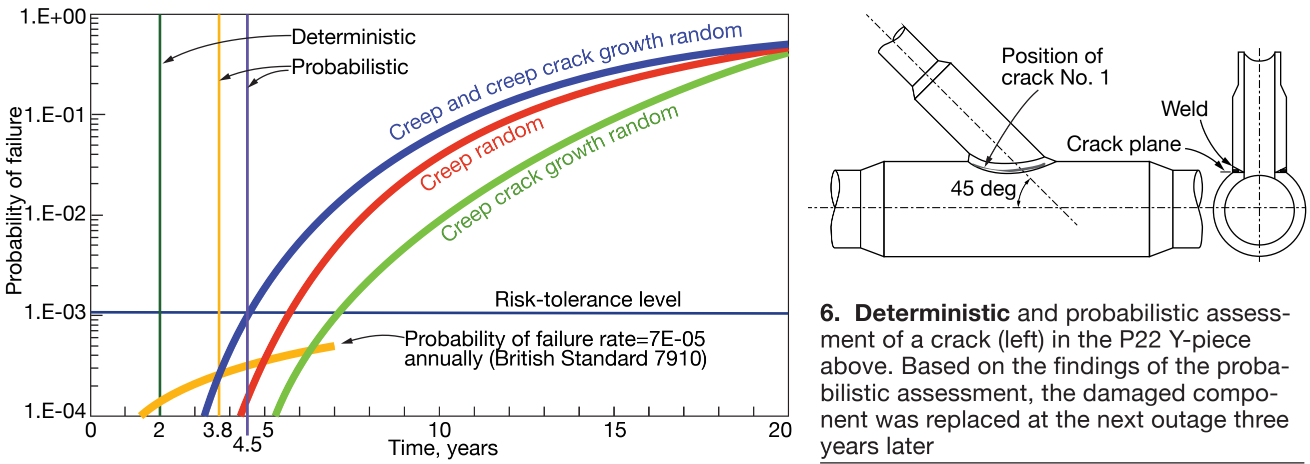
Forums

- 7F Combustion Turbines
- Combined-Cycle Steam Turbines
- Combined-Cycle Users
- Generators
- Heat-Recovery Steam Generators
  (moderated by Bob Anderson)
- Power Plant Controls

Power Users Group is a non-profit company managed by Users for Users. It is designed to help Users share information and get solutions to power-production problems.

www.PowerUsers.org

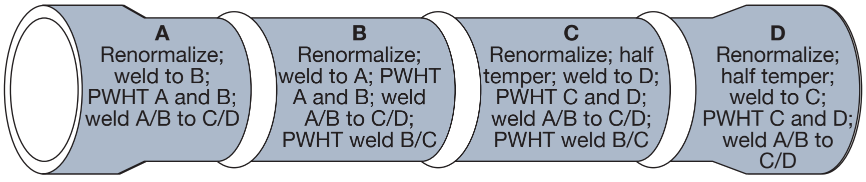


6. Deterministic and probabilistic assessment of a crack (left) in the P22 Y-piece above. Based on the findings of the probabilistic assessment, the damaged component was replaced at the next outage three years later

revising the heat-treatment cycle for P91 welding with some changes to the welding processes. The initial basis is specific research in both Japan and the UK that shows weldment rupture life improvement by a factor of two to three. Japanese and UK companies have committed support; additional sponsors are invited. Fig 7 shows some of the planned pipe tests.

Drones. ETD is also beginning a group-sponsored project to study drones, robots, and other automated devices available in the market, and to develop recommendations for appropriate and cost-effective devices that may even be used as consumables. This includes 3-D printed drones with light plastic frames and safety cages. Ultimate uses include inspection and possibly repair capabilities.

Shibli ended the interview, conducted by Consulting Editor Steve Stultz, by referring readers interested in learning more about these and other projects to the organization's website (www.etd-consulting.com). CCJ



Notes: Weld A/B on renormalized-only material; weld C/D on renormalized and half-tempered material; weld B/C on conventionally normalized and tempered material

7. Planned P91 pipe tests

How to prevent an actuator failure from tripping your plant

The value of user groups continues to grow in the electric power industry as the number of employees on the deck plates shrinks and personnel with deep experience retire.

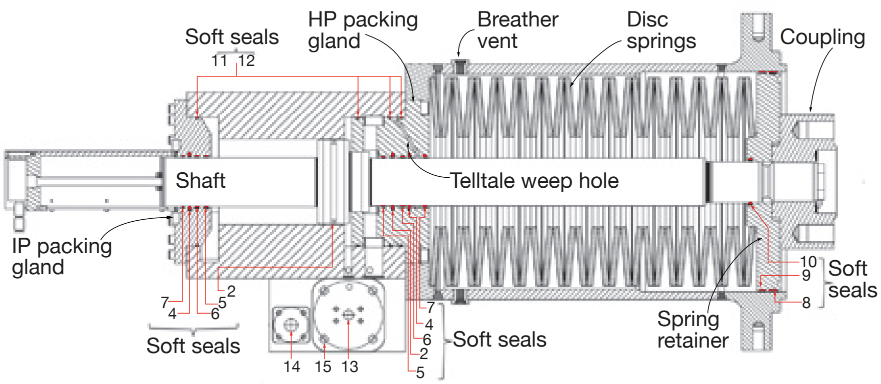
The plant manager for a 2 × 1 J-class combined cycle under construction told the editors he had received more than 500 resumes in the last two months for about 20 hourly positions at the facility. Two-dozen employees is the total headcount planned. Given that most candidates are not familiar with this gas turbine—only a handful of J engines are operating worldwide and the US fleet leader had less than a year of service time in February 2018—training time likely will focus on the GT because it is the revenue resource. Certainly would make sense.

What about the other equipment? Who is the subject matter expert (SME) on steam-turbine valve actuators, for example? Anyone? Not likely. The editors picked this for illustrative purposes because their Rankine Cycle experience comes from the nuclear and coal-fired plants home to large, hydraulically actuated steam valves and big staffs with SMEs for virtually every piece of equipment.

Before the Steam Turbine Users Group was launched in 2013, the major gas-turbine users groups may have dedicated half a day to steamers. STUG enabled owner/operators to drill down on important steam-turbine (ST) topics, like actuators, that weren't covered previously because of time constraints (Fig 1).

Actuator inspection and overhaul was on the agenda for STUG 2016 and then again in 2017. If you're a neophyte and don't understand why this subject would be discussed two years in a row, by the same company (MD&A), you ask someone on the steering committee.

Here's what the editors were told by a committee member with decades of GE steamer experience: Back in the days of "big steam," he said, GE, the dominant turbine supplier, made its own actuators, which might have run for 30 years with little or no maintenance. In the combined-cycle era, Bosch Rexroth AG has supplied the majority of actuators for large steam valves and those must be overhauled every five to eight years.



1. Generic actuator drawing shows key components

Some actuator designs have specific issues that require close attention. For example, Rexroth actuators for Toshiba steam turbines are very large and oriented horizontally creating wear points that might not be found in the vertically mounted actuators on GE machines.

In the mind of this committee member, at least, actuators for turbine valves may be the most important "forgotten" component in a steam plant. Many problems, he said, can be traced to water ingress and maintenance inexperience. At his company, in-service failures and numerous servo and solenoid issues that had occurred when station O&M personnel were charged with maintaining actuators in-house have been avoided by contracting the work to a specialty shop.

But, the turbine expert cautioned that there are no guarantees when it comes to actuator reliability. Inspection and soft-parts replacement, which typically are scheduled during steam-turbine minor inspections, are done at intervals of about five years—a long time given the wear and tear traced to today's demanding cycling requirements.

Because you don't know exactly what you'll find when an actuator is dismantled for inspection, be sure the overhaul partner you select can assure the ready availability of parts—unless you have a back-up set of actuators, as some owners do. Scuttlebutt suggests that getting parts from Rexroth, a German company, can be challenging. However, most users are likely to agree that Rexroth has the best actuator on the market today for steam valves.

To learn more about what owner/operators can do to minimize actuator issues, the editors spoke with MD&A's Anthony Catanese, an engineer on the front lines of the company's Ohio overhaul shop and the SME invited to speak at STUG 2017.

Actuator performance and lifecycle are influenced most by the cleanliness of the hydraulic fluid and your ability to restrict water ingress, Catanese said. Varnish presents a double whammy: It can plug the 4- and 10-micron filters for the servos, the actuator's "brain." Plus, it can combine with oxidation products produced during the degradation of the hydraulic fluid to form rust (Fig 2) and varnish (Figs 3 and 4) that inhibits actuator operation and may reduce spring life.

Given the importance of actuators and how easy they can be to forget in

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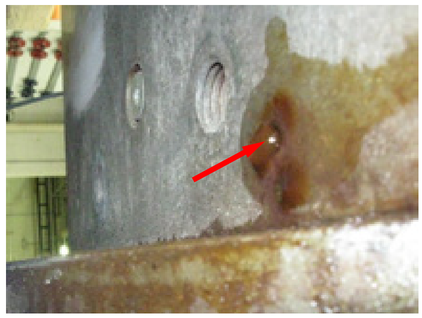
2. Steam leaks and moisture inside spring can contribute to rust and broken springs

3, 4. Cleanliness of hydraulic fluid is key to prolonged life of soft seals and auxiliary valves



5. Telltale weep-hole leakage indicates deterioration of soft seals in the packing glands

6. Damage to hard parts is caused by infrequent maintenance intervals and deterioration of soft parts

the daily crush of plant activity, consider assigning responsibility for them to one person in the O&M department. There's not that much to do except keep after the few recommended activities for relatively few valves—eight in the case of a GE D11, an integral part of the OEM's 2 × 1 and 3 × 1 combined cycles. Those plants typically are equipped with two each stop, intercept, control, and reheat valves.

Rexroth recommends the following for each valve:

- Quarterly, check the filter indicator.
- Every two years, change filters and check spring cans for proper function and corrosion.
- Every five years, change all seals.

When scheduling D11 overhauls, Catanese notes that some customers have opted to inspect and refurbish two valves every year to level both cost and outage time on an annual basis. Most often only about a week or two of scheduled shop time is required for the basic "open/clean/close" process and replacement of soft parts for a full set of eight actuators. An incoming inspection report with shop recommendations is generated shortly after actuator receipt. Plant personnel are invited to verify the report's findings, discuss the recommendations, and witness testing after work is complete.

Of course, the technician assigned responsibility for actuators should be looking at them periodically when out in the plant. One of the first signs of concern often is leakage out of the packing-gland telltale weep hole (Fig 5). If borescope examination of the spring reveals moisture or rust, maintenance should be scheduled soon.

7, 8. Keeping moisture out of spring cans helps prevent broken springs and shaft damage

Moisture causes rust which can cause broken springs which, in turn, score the shaft (Fig 6) and promote increased leakage. Plus, moisture can accumulate and contribute to the failure of springs on vertically mounted actuators (Figs 7 and 8). As a stop-gap measure, consider removing a breather vent and using dry shop air to pressurize the actuator, thereby preventing water/steam accumulation in the spring can.

Given the problems with varnish and moisture ingress that can arise over an actuator's lifetime, it makes sense to spend time at the design stage to select the optimal hydraulic fluid for the service. If problems arise in service, give thought to replacing the fluid with one better suited to your application.

Listed below are the three most popular hydraulic fluids for actuators

9. A proper shipping container is needed to assure safe transport and storage operating large steam valves. All are fire-resistant. Comments are culled from notes taken by the editors at user-group meetings.

- Fyrquel®. Poisonous fumes that can be released if the fluid is heated to decomposition is a concern of some users. Also, this fluid reacts with water to form phosphoric acid and gels conducive to spring damage/failure.
- Quintolubric®, like Fyrquel, is a hydrolytically unstable ester. It is associated with varnish and acid formation.
- EcoSafe® is hydroscopic, but the saturation limit where water becomes "free" is high—16,000 ppm. Given the sensitivity of actuators to free water, American Chemical Technologies suggests a conservative 7500 ppm as an upper limit for sampling purposes. Water remains tied up in the fluid and unable to attack metal. Plus, EcoSafe, a polyalkylene glycol (PAG), is chemically incapable of producing insoluble varnish. All products of decomposition remain infinitely soluble in the base stock.

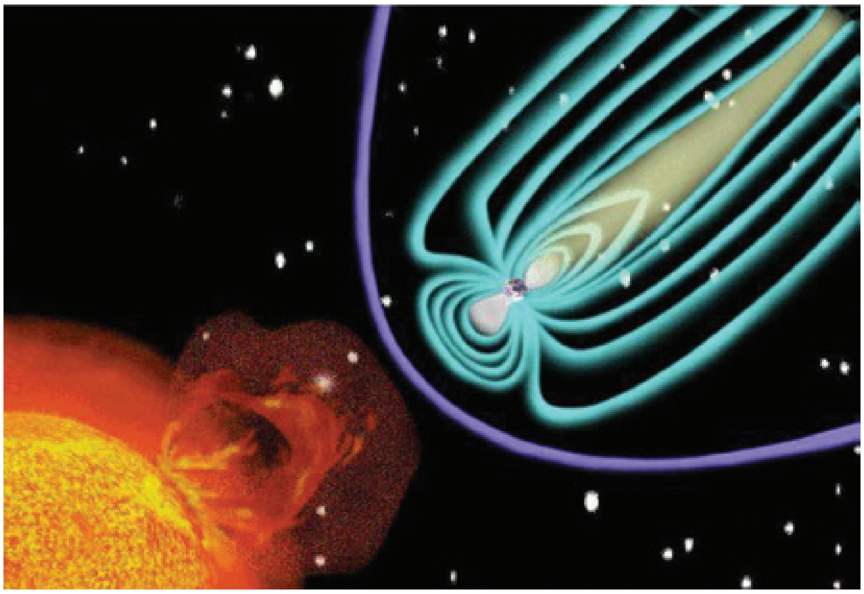
Finally, when your actuators leave the shop, be sure they are properly crated for shipment and possible long-term storage and secured in an upright position (Fig 9). CCJ

New NERC standard aims to mitigate effects of GMDs

By Thomas F Armistead, Consulting Editor

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

When one of the eruptions is aimed directly at Earth, the results can be catastrophic. Loss of reactive power is the most likely outcome from a severe solar storm centered over North America, according to a report released in 2012 by the North American Electric Reliability Corp. Significant losses of reactive power could lead to voltage instability and, if not identified and managed appropriately, power-system voltage collapse could occur. In response to the findings, NERC is developing and gradually implementing new standards for the continent's bulk-power system.

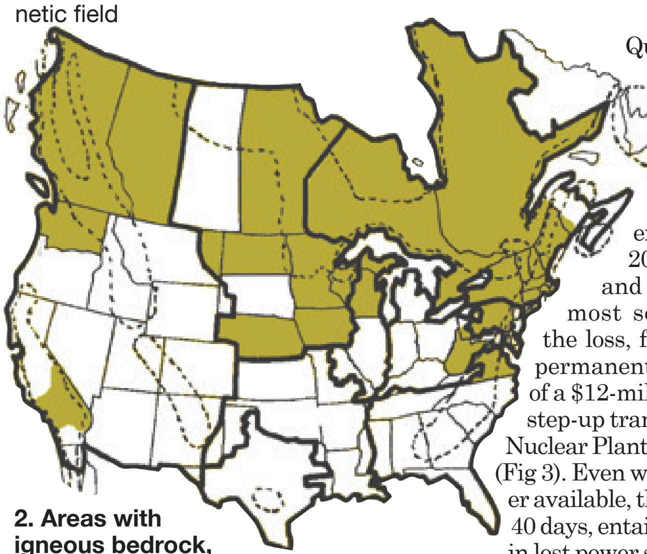


1. A powerful coronal mass ejection engulfs the Earth and distorts its magnetic field

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

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

But the resistive igneous bedrock of the Canadian Shield forced the current to seek easier conductance (Fig 2). It entered the electric grid through ground wires and propagated throughout Hydro-Québec's system. Within 92 seconds it brought down almost the entire grid, knocking 21,500 MW off line. The blackout lasted more than nine hours, affected 6 million people, and cost $2 billion.



2. Areas with igneous bedrock, located inside the dashed lines, are at higher risk of geomagnetically induced current (color)

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

Playing defense

To forestall a repetition or worse outcome, in January 2015, NERC filed TPL-007-1, "Transmission System Planned

Performance for Geomagnetic Disturbance Events." The standard requires North American ISOs and utilities to perform state-of-the-art vulnerability assessments of their systems and equipment for potential impacts from a severe, once-a-century benchmark geomagnetic disturbance event (GMD) and to mitigate identified impacts. Mitigation could include changes in system or equipment design or the installation of hardware to monitor or reduce the flow of geomagnetically induced currents (GIC). TPL-007-1 was approved by the Federal Energy Regulatory Commission in September 2016 (Fig 4).

The requirements are designed to be implemented over a five-year period, said Mark Olson, NERC senior engineer in reliability assessments. Entities began implementing the standard in 2017 and must take several steps leading to completion of the vulnerability assessments and mitigation plans by 2022. At FERC's direction, NERC is developing a revision to be labeled TPL-007-2. It will enhance the benchmark GMD event used in the vulnerability assessments and is due for completion by May 2018.

Another NERC reliability standard, EOP-010-1, was approved by FERC in June 2014 and took effect in early 2015. The EOP-010-1 standard requires grid operators to have procedures that can be put in place to reduce impacts of severe GMD events.

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

Anticipation

The National Oceanic and Atmospheric Administration (NOAA), which operates the National Weather Service, has a Space Weather Prediction Center in Boulder, Colo, which monitors solar activity. And like the National Weather Service, which forecasts hurricanes by observing precursors such as tropical depressions in the Atlantic, the Space Weather Center tracks the development of sunspot groups to forecast GMDs, said Bill Murtagh, program coordinator for the center.

When large, complex sunspot groups emerge, "they may create eruptive activity called mass ejections that can have impacts here on Earth," he said. "Isolated, complex sunspot clusters will produce coronal-mass ejections (CME) of significance that will create sizeable GMDs here on Earth."

The current 11-year solar cycle began in December 2008 and reached solar maximum in April 2014, Murtagh said. "In the waning stages of the solar cycle, we get quite a few coronal-hole high-speed solar wind streams." Coronal holes are large areas on the sun with lower magnetic fields allowing increased solar wind, he said.

"Solar-wind instruments will typically measure in backgrounds around 400 kilometers per second. One of the high-speed streams of solar wind associated with coronal holes will sweep past the Earth and buffet the Earth's magnetic field for a couple of days, sometimes up to about 600 km/sec, and that's a moderate-level storm."

What happens in a geomagnetic disturbance

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

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

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

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

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

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

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

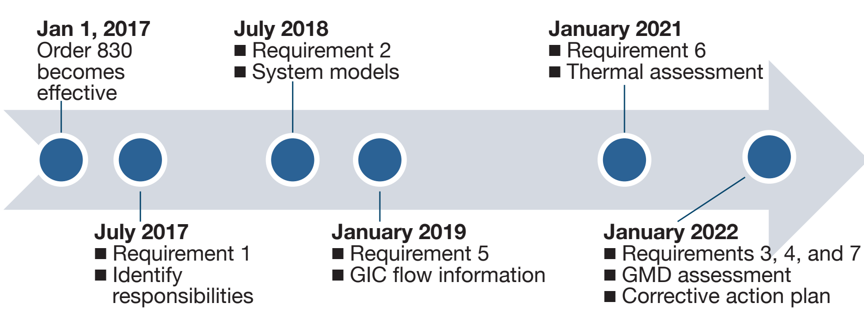
Heat damage or torsional damage could also appear on the generator/turbine shaft system, said John Kappenman, a leading expert on GMD and owner of Storm Analysis Consultants, Duluth, Minn. "Protective systems on the generator may not be well suited to detect this threat."

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

At this stage of the cycle, we should expect an increase in "moderate-level GMD, but we will continue to see isolated strong GMD associated with sunspot groups," Murtagh said. "We typically see a couple of big clusters emerge over the course of these waning years at the three- to five- or six-year point." A big sunspot group emerged in early September, he added.

The next solar maximum is expected in 2025, but Murtagh would not predict the intensity of the ramp-up to the maximum. "The 11-year cycle in itself is obviously quite predictable," but the GMDs are not. He compares predicting GMDs with predicting hurricanes at the beginning of hurricane season. "Sometimes you get two or three hurricanes and other times you can get 20 hurricanes in a season. In the sunspot cycles, we've seen very big cycles, like Solar Cycle 19 back in the 1950s and early 1960s, and then we've seen this cycle, which is actually the smallest cycle since the first decade or two of the 1900s."

Geomagnetically induced currents are the terrestrial events caused by GMDs. "When a coronal-mass ejection with its own magnetic field that gets shot out from the sun hits Earth, it hits Earth's magnetic field, so we get two magnets coming together," Murtagh said. "The interaction of the magnetic fields ends up inducing currents above us in the atmosphere, above the ionosphere, and those currents above manifest themselves on Earth in the form of geomagnetically induced currents."



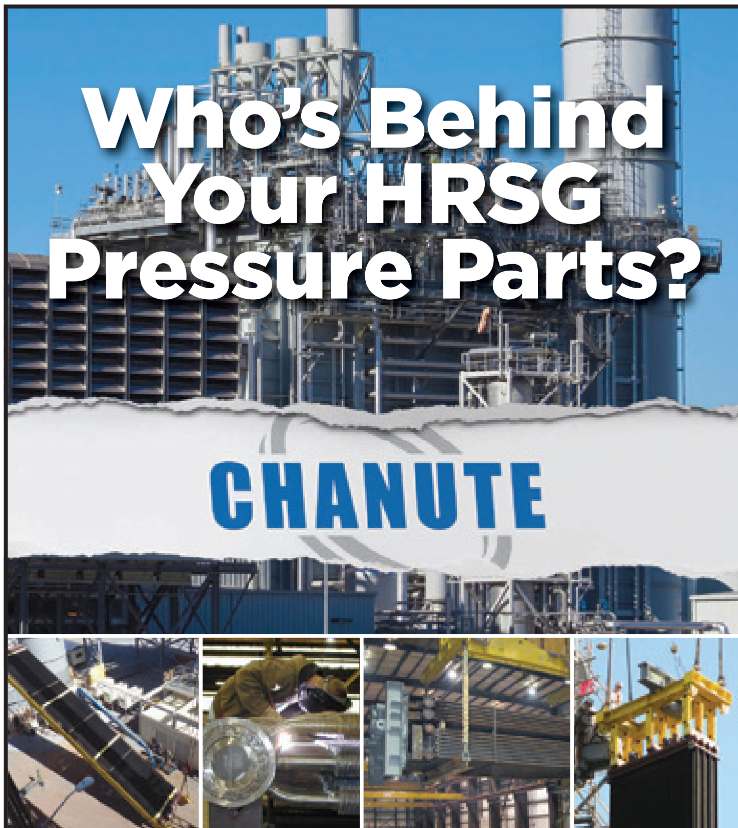
4. Implementation plan for NERC's new TPL-007-1 reliability standard extends through early 2022. Access the details at https://www.ferc.gov/whats-new/comm-meet/2016/092216/E-4.pdf

Earthly effects

Earth is affected only when a CME is directed at Earth, but there is no way, given the state of the science, to forecast when a CME directed at Earth will occur. Instead, Murtagh expresses the situation in probabilities. If he detects a very large sunspot cluster in the middle of the sun, "my probability of an eruption of a CME to occur is at 80%." Probability is as much as he can do with the science he has. Being able to identify a pre-eruptive signature that would allow more precise forecasting is one of the industry's "holy grails," he said. "We're not there yet."

Like the National Weather Service, Murtagh produces routine daily forecasts. If sunspot activity indicates an 80% probability, NOAA would announce that level of probability, as a local weather station might announce a 50% chance of a thunderstorm. But when the threat reaches a certain threshold, he starts putting out alerts and warnings, just as a weather station might announce a tornado watch or tornado warning.

"We do it the same way. That product would go out as a forecast, saying, '80% chance of an eruption today.' Then when the eruption occurs, and especially when we see a CME that's



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Earth-directed, we issue a 'watch product,'" which, like a weather watch, alerts recipients to the potential for an active threat.

NERC asked EPRI for assistance in responding to FERC's request for validation of the GMD standard, said Rob Manning, EPRI's VP of transmission and distribution infrastructure, and the research organization is working with the electric utility industry to evaluate the standard in further depth, doing calculations and validations and technical basis for the standard.

A geomagnetic disturbance created by a solar flare has only one characteristic: geomagnetically induced currents, primarily on the transmission system, Manning said. It manifests itself as heating in the transformer cores, depending on how high the current gets, because it saturates ac transformer cores. The primary danger from a solar-flare-type occurrence would be the loss of transformation in the switchyard. A secondary outcome would be harmonics in the plant. "If you're protected against harmonics in general, you're probably pretty well protected against GIC," he said.

EPRI sponsors Sunburst, a system of sensors deployed around North America, which measures GICs on the grid and reports them to utilities. "We can tell you at any time what the actual GIC current flows are," Manning said. "With a solar flare, we generally believe we would have adequate time to isolate transformers that are potentially susceptible to damage."

Unless you get a particularly catastrophic solar flare, it would be relatively slow heating, so you would have several minutes to several hours to take a transformer offline, which would then completely protect it from GIC.

The net result from that might be an unscheduled shutdown of the generating plant if there were a solar flare and the operators were able to confirm two things: one, that they are seeing GIC currents flow in the Sunburst system and two, the transformer is showing additional heating. If you see those two factors, that might be enough to shut down the plant to save it. You can reboot it back after the solar flare is past."

Distributed energy resources, energy storage, and other latter-day evolutions in the grid have not materially modified the risks of exposure to GIC. "The primary susceptibility to GIC currents is very long lines, radial lines," Manning said. A very long radial line can accumulate GIC, and it can only go to the end of that line, where it can damage equipment. Microgrids and distributed solar power are not likely to be susceptible to GIC.

At risk

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

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

Completion of Reliability Standard TPL-007-2 by NERC and approval of the standard by FERC by 2022 will provide transmission planners with new tools to help ensure the bulk-power system's ability to withstand and mitigate the effects of potentially damaging solar activity. **CCJ**

Real-time optimization pushes out into distribution networks

The optimization of the utility production and delivery system at the University of Texas, Austin (UT-Austin) is the poster child for a work in progress. After all, you don't optimize a 90-year-old powerplant, one with a mix of really old boilers and state-of-the-art gas turbine/HRSGs overnight or even in a few years. It's also a glimpse into the new world of microgrid integration with utility grids, although you'd hardly call this one "micro."

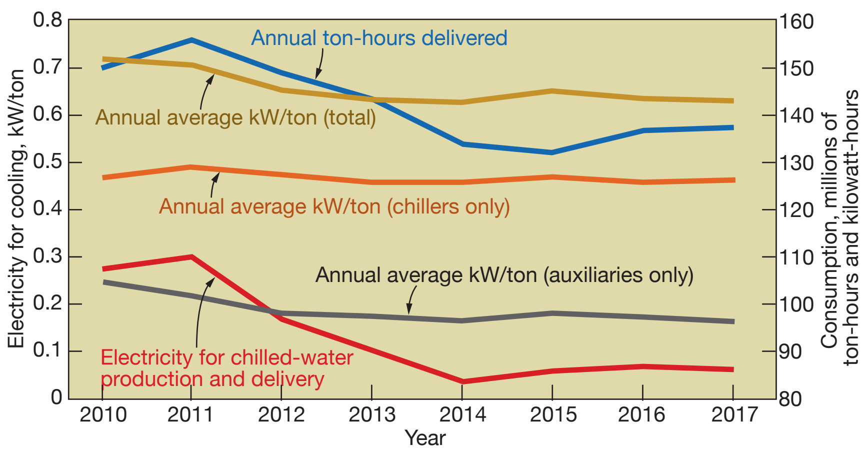
Five years ago, CCJ editors visited the Carl J Eckhardt Heating & Power Complex to report on the plant's use of state-of-the-art optimization and analytics software (CCJ, 3Q/2012, p 4) and numerous major equipment upgrades and additions. The plant delivers electricity, chilled water, hot water, and steam to a campus of more than 160 buildings serving over 50,000 students.

The editors stopped in during a jaunt through central Texas in January 2018 to get some detail around presentations given by Associate VP Juan Ontiveros and Associate Director Roberto Del Real at last year's Ovation™ Users' Group Conference, held in Pittsburgh. "We've now optimized the distribution network, not just the production facilities," they said.

Critical pieces of the most recent optimization effort are the upgrade of the Ovation Electrical Control Energy Management System (ECEMS), dozens of hardwired sensors, and a new chilled-water storage tank. The ECEMS replaces manual control of the four major electrical tie-lines and regulates the campus grid/municipal grid interface with these two overarching goals in mind:

- Don't exceed the campus' 25-MW peak demand charge.
- Maintain the grid interface at net zero without exceeding the responsiveness of the turbine/generators and while maintaining campus demand.

Simply, the controller monitors the purchased power during each 15-min demand period. The logic calculates the amount of purchased power (MW), which is in excess of the demand limit. When this number is greater than zero, it is the responsibility of the generator load-control program and load-shedding program to ensure that the demand limit is not exceeded.



Cooling-plant performance has improved dramatically in the current decade. Since 2010, UT-Austin has grown by 2.4 million ft^2 (gross) while reducing cooling requirements by 12.4 million ton-hours and the amount of electricity used for cooling by 20.9 million kWh

Campus internal generation is increased by the amount of power generated by this logic. This also gives the campus the ability to sell power back to the grid when the opportunity is presented. Real-time internal production costs and current grid market prices are used to constantly balance internal generation, purchased power, and power sales. At the same time, the ECEMS monitors hundreds of discrete load points with the capability to remove load in less than 100 milliseconds (ms).

UT-Austin also has optimized the chilled-water grid so that it uses the least amount of pumping power to meet demand. This has reduced peak pumping from 70,000 gal/min to 40,000. Differential pressure (dP) between supply and return lines, measured at key buildings on campus, is updated in real time while the pumping speed gets adjusted to follow a low-dP set point in endless iterations with a rate-of-change of 0.25 dP/min.

This low differential pressure has the benefit of satisfying campus demand with less pumping power. The lower-speed flow set points also are optimized in other chilling stations while keeping one assigned for controlling dP. Pumps are equipped with variable-frequency drives (VFD) which lower speed, thus achieving maximum accuracy and controllability.

Because pumping horsepower varies with the cube of rpm, reducing flow has a dramatic effect on power consumption. But it also has a positive impact on O&M: Over-pumping can lift the seats in the control valves and lead to other maintenance impacts.

The plant is equipped with 18 electrical chillers but now, because the optimization effort, occasionally only one chiller unit is needed during some winter periods to serve the entire campus. With the dramatic drop in peak cooling load came a drop in steam flow to produce the required electricity. The plant no longer has to over-deliver cooling at too low of a temperature in winter; now it is able to set the chilled water system at 44F, rather than 39F. This temperature reset follows outside air temperature linearly between 80F and 55F.

Electrical production efficiency is

maximized when plant output stays below 70 MW, noted Del Real and Ontiveros. Campus peak load is 60 MW but the powerplant has a maximum production capacity of 140 MW. By adding a 6-million-gal chilled-water storage tank, they explained, they can "shift" 10 MW during the night, make and store chilled water, and "baseline" the most efficient gas turbine/generator. Cutting out a chiller in the summer is an easy way to shed electric load, with stored chilled water from the off-hours making up the difference.

Thus, another goal of the overall strategy is to run the most efficient turbine/generator, the LM2500 installed in 2010, eight months out of the year, as opposed to four earlier.

The Ovation ECEMS controller gives the plant the capability to "island under any configuration of generators" (the defining characteristic of a "microgrid"). Said Ontiveros: "During islanding, load shedding becomes really important and the chilled-water storage acts like a big battery—it allows us to ramp the generators comfortably."

Having 70 variable-frequency drives (VFDs) with inverters, as well as numerous other inverters operating in the system, brings its own unintended consequences: Harmonics and low power factor because of nonlinear loads and inductive motors, respectively.

The ECEMS includes an automatic VAR control system, which summons VARs out of the generators to maintain a minimum 95% power factor. Advisory control is also a key feature that helps the operator making decisions on which capacitor bank should be brought online for voltage control. The city tie is kept at net unity power factor.

Said Del Real: "The grid connection is what controls our grid frequency. If separation from the city grid occurs, and if the load were to exceed generation, we would then need to shed load fast enough to 'beat' the disturbance, requiring a 100-ms response."

Thus, the ECEMS continuously analyses and updates campus electrical demand, advises the operator on when to stage capacitor banks in and out of service, monitors generator load profiles, and regulates city purchased power while maintaining appropriate power factors in a system that's become more sensitive because of the presence of dozens of sensitive loads.

Views into the "real-time energy dashboard" built into a campus mapping app allow operators to drill down to the building level (though not submetered) and see meters which are not working, monitor all utility flows, and even auto-text outage information to building custodians. Meters are also used to automate the billing to individual customers.

On the plant management side, another consequence has been that the facility is saving significant money on fuel because it operates at optimized production and delivery points, but fixed costs are higher because of the need to maintain the new equipment and demand-side strategies. As with many owner/operators, campus administration loves the cost savings but investing it back into the facility? Not so much.

Yet the performance quest, and the work in progress continues. Del Real said they are investigating transformer efficiency monitoring and "right-sizing" transformer capacity (since they tend to be oversized) as the next steps in optimization. CCJ

UT-Austin utilities production and delivery: Pertinent details

- 140 MW of internal generation capability, 60 MW of peak demand.
- 9.5 million gal of chilled-water storage capacity, two tanks, five chilling stations with 18 chillers total, six miles of piping.
- 60,000 tons of cooling capacity, 33,000 tons of peak demand.
- Four electrical grid ties to the municipal utility, 69-kV transmission feeds, 32 miles of electrical duct banks, internal electricity generated and distributed at 12 kV and 4160 V.
- 18-million ft^2 of building space served.
- Two gas turbine/generators with HRSGs, four gas-fired boilers feeding four steam turbine/generators at 425 psig/710F.
- 160-psig steam distributed through the campus heating grid.
- Two independent gas main feeds into the plant.
- Close to 1000 meters monitoring electricity usage, steam, chilled water, and domestic water.
- Overall annual efficiency of 84% to 87% based on Btu generated divided by Btu purchased, making it one of the most efficient district heating and cooling systems in operation, and the first university to be certified PEER (Performance Excellence in Electricity Renewal) by the United States Green Building Council.

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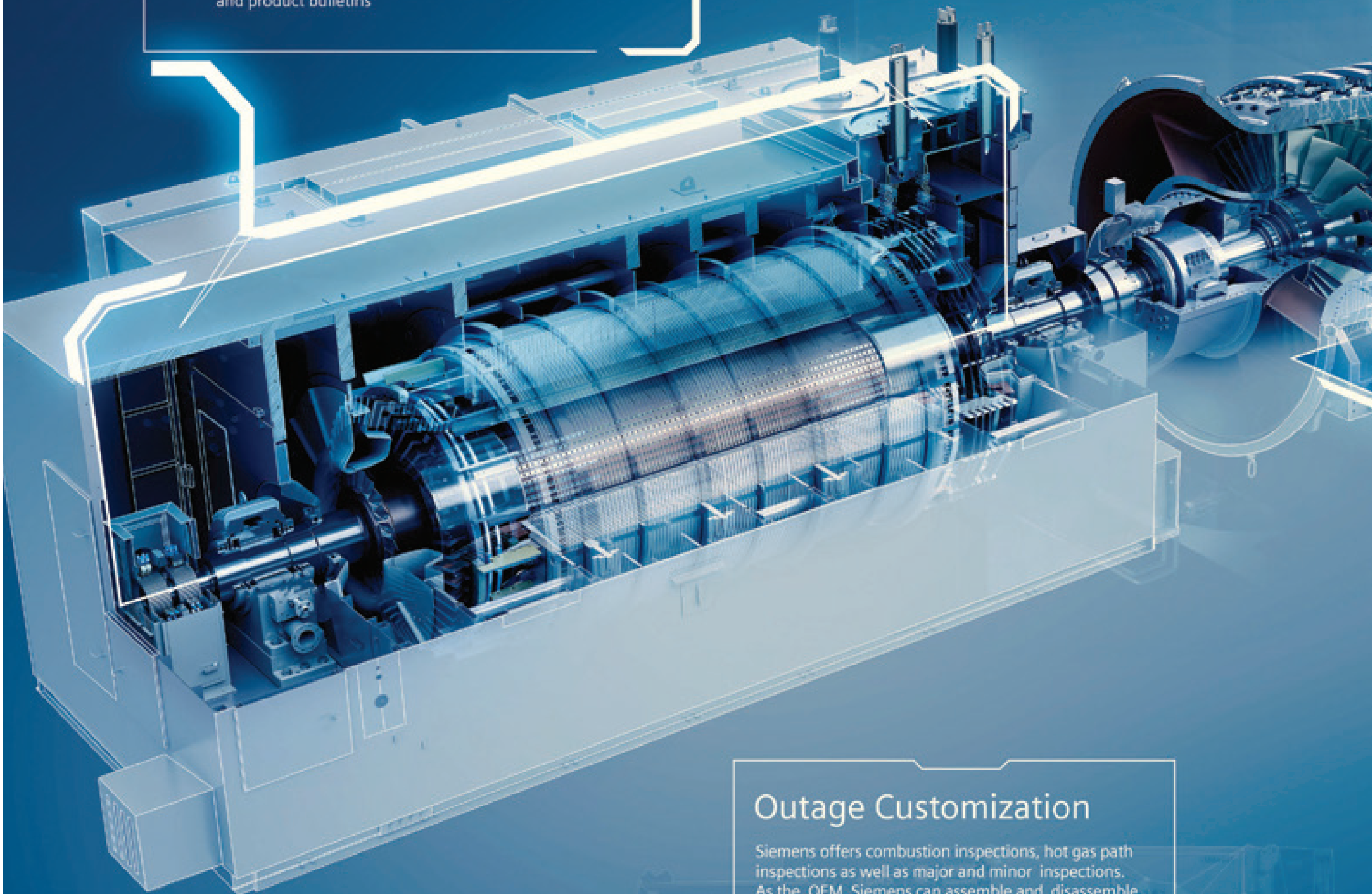

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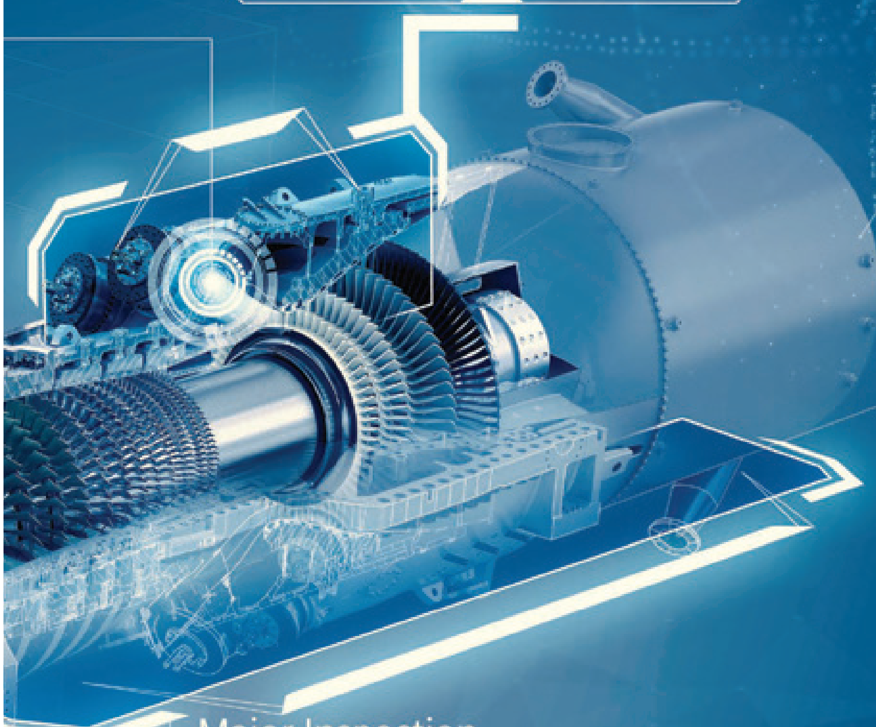
- Removal of turbine cover
- Remove/inspect/replace hot gas path components based on operational history
- Borescope inspect compressor section via accessible ports



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- Remove/inspect/replace compressor components based on service life
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Utilities embrace digital technology within the same old business models

The changing nature of electric supply

Special to the COMBINED CYCLE Journal
Jason Makansi, chairman, Editorial Advisory Board
GRiD TODAY

Spending two full days at the DistribuTECH® 2018 Conference & Exposition in San Antonio, Tex, in January, was an opportunity for the editors of GRiD-*Today* and CCJ to assess progress as the electricity industry "transforms" from centralized to distributed assets with customer service at the core of the enterprise. Or so all the executives were saying.

The concept of a "smart city" was certainly a prevalent theme, an evolution in buzzy phrases from smart meter followed by smart grid, as was the notion of a "digital utility." During the keynote talks, a utility executive for a large municipal noted that the company is uniquely suited to be a smart city.

An executive from the largest state-owned public utility in the country told the audience it is working to become the first "all-digital utility."

Both have built and are managing significant technology development centers to achieve these goals.

Of course, no one defined what exactly is a smart city or a digital utility, nor did anyone broach what the term smart city might imply about rural areas.

Later in one of the mega-sessions, a representative from one of the country's largest investor-owned utilities said they were "looking to replace existing assets with new, smarter, and better ones." This utility is, by the way, one of the largest coal-based utilities, too, which tells you something.

The traditional utility business model is to earn a regulated rate-of-return investing in assets over a long time horizon. Smart cities and an "all digital utility" are grand central planning strategies which utilities are comfortable with, even if they are designed for "decentralized" infrastructure.

The muni executive gave an insightful company factoid: Last year the utility had 8470 MW of capacity in operation; in 2020 they expect to reduce that to 7880 MW, while adding 650 jobs. Clearly, those workers are not destined for the powerplants or transmission network. The executive said the company considers the community it serves "energy advisors." That's an advisory committee meeting one would probably make any excuse to avoid.

Not your father's utility bill. The customer-services technology platforms being implemented are nothing like a paper utility billing statement delivered monthly. The hardware model, according to presentations and what was being exhibited on the floor, is the smart phone; the customer experience model is Amazon, and the engagement is intended to be 24/7/365.

Descriptions and demonstrations of these customer/utility interfaces were truly dazzling, with systems controlling a two-way transactional electricity flow interface with the utility, rooftop solar, smart thermostat and HVAC, behind-the-meter storage, electric-vehicle charging station, and more. Customers can chart and alter (or not) behavior, costs, and revenue (if they are selling power back) patterns through data visibility.

Demand side management (DSM), in other words, has come a long way from the utility subsidizing the replacement of an old refrigerator with an efficient one, while the ratepayer plugs in the old one in the basement to keep the beer cold. That was DSM circa 1970s.

Still early days. Despite the promise and potential, the smart-digital transformation is still in its infancy. Utility representatives generally talked more about their "initiatives" and future plans, their technology development programs, and results from initial demo facilities than they did of replicable commercial projects. As one example, the muni utility mentioned above has only one microgrid currently in operation. Meanwhile, the engineers and technocrats grappled with the nuts and bolts of making this stuff work.

Across several sessions addressing microgrid challenges and lessons learned, what was clear is that the one function that essentially distinguishes a microgrid from a conventional power and electrical system serving an industrial facility, for example—the capability to "island" (or safely disconnect) from the utility or larger grid in responding to a disturbance, keep operating, and then automatically reconnecting when the disturbance is cleared—is still the greatest challenge.

In one presentation, the microgrid manager noted that "it was a challenge going from island" operation back to the grid-connected operating state. Further, that seamless transitions work but you may need to shed some load." That actually doesn't sound like a seamless transition.

Another microgrid operator "was not able to demonstrate transitioning from islanded to grid-connected operation. In this project, one problem was that the battery-storage communication system couldn't react fast enough to synchronize the battery to utility frequency.

Other challenges mentioned by several with demo-project experience included:

- Accommodating cloud-induced variability with solar PV systems.
- Contracting for, and integrating, state-of-the-art components from multiple suppliers into a coherent system design.
- Understanding and complying with building codes and standards and new standards for microgrid components and grid interfaces, which are still evolving.
- Control and communications protocols and cybersecurity issues among different subsystems (storage, PV, microturbine/generator, etc).
- Loop testing hardware with real-time digital simulation (described by one presenter as critical).
- Handling reactive load profiles and providing reactive power support (one presenter mentioning the application of "smart" inverters).

Finally several C-suite challenges were noted, perhaps unintentionally. For example, a representative of a large nuclear-based utility with a national footprint said they were "pursuing a customer and energy services business model" while also noting that "the customer experience [stuff] is only 5% of the utility's annual expenditures." Protecting current revenue sources while pursuing hot new growth areas is always a fundamental challenge for executives of large companies.

One executive noted that "the future is in energy storage." However, it's also true that reliable, affordable storage is what could decouple customers from the utility grid, reduce the need for purchased utility power to the emergency backup category, and allow new market entrants to manage a customer's residential or commercial energy infrastructure. Thus, the real race may be to pay off existing "dumb" assets and retain ratepayers with dazzling new services delivered through an Amazon-like interface before Amazon and others like it dis-intermediate the utility altogether. CCJ

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Turbine blade, vane cooling—a primer

By Lee S Langston, professor emeritus, UConn

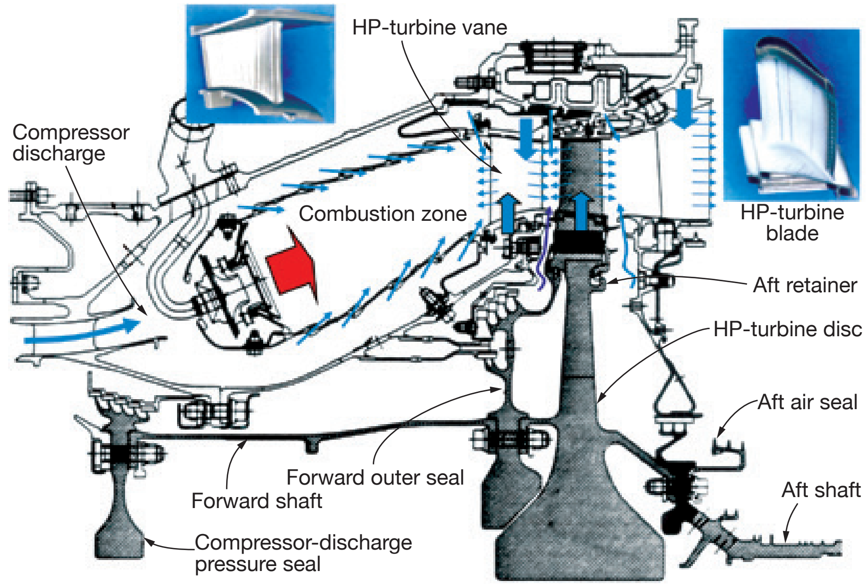
The most efficient powerplants ever produced are now entering service. These latest and largest combined cycles—powered by GE's 7HA, Siemens' SGT6-8000H, and Mitsubishi Hitachi's M501J engines—are all clocking in at 62% - 63% thermal efficiency. This makes them the most efficient heat engines yet perfected by engineers, with all three OEMs striving to reach 65% in coming years.

The gas turbines are state-of-the-art. They make extensive use of turbine blade and vane cooling, thereby allowing the high turbine inlet temperatures required to achieve record-breaking efficiencies. Cooling air drawn from the compressor gas path (as much as 20%) is used to protect hot section parts in both combustors and turbines.

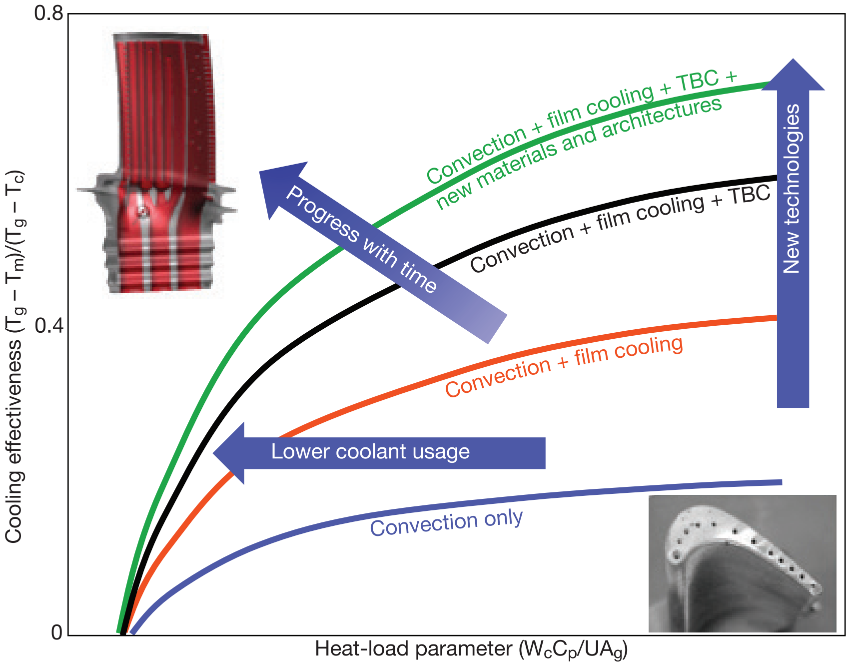
Turbine cooling details. Thermal efficiency increases with the temperature of the gas exiting the combustor and entering the turbine—the work-producing component. Turbine inlet temperatures for modern high-performance commercial jet engines can reach 3000F, while gas turbines in electric-power service typically operate at 2700F or lower and military jets in the neighborhood of 3600F. (The turbine designer must accommodate for excursions above these nominal temperatures, because of combustor hot streaks, etc.)

In the highest-temperature regions of the turbine, special high-melting-point nickel-base-alloy cast blades and vanes are used because of their ability to retain strength and resist hot corrosion at extreme temperatures. These so-called superalloys, when conventionally vacuum cast, soften and melt at temperatures between about 2200F and 2500F.

This means blades and vanes closest to the combustor can be operating at gas-path temperatures far exceeding their melting points. To endure temperatures of 500F to 1400F above melting, they must be cooled to acceptable service temperature (typically eight- to nine-tenths of their lower melting



1. Cooling of high-pressure hot-section components—including stationary vanes or nozzles, rotating blades or buckets, shrouds, combustion liners, and flame-holding segments—may be active or passive



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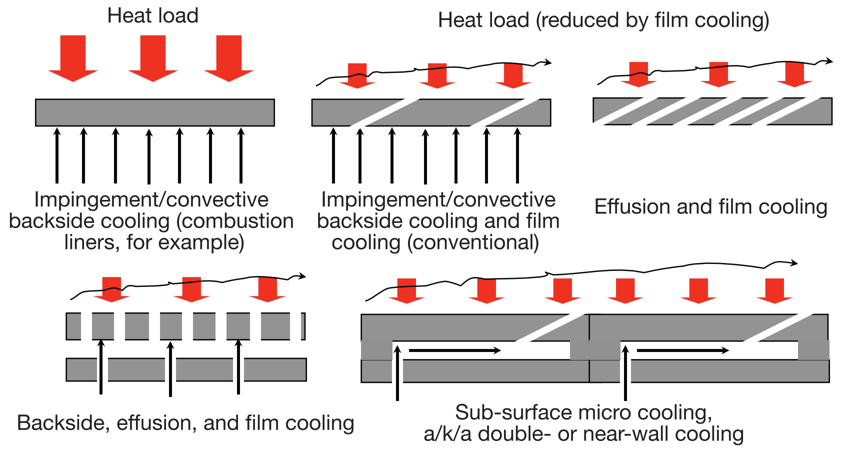

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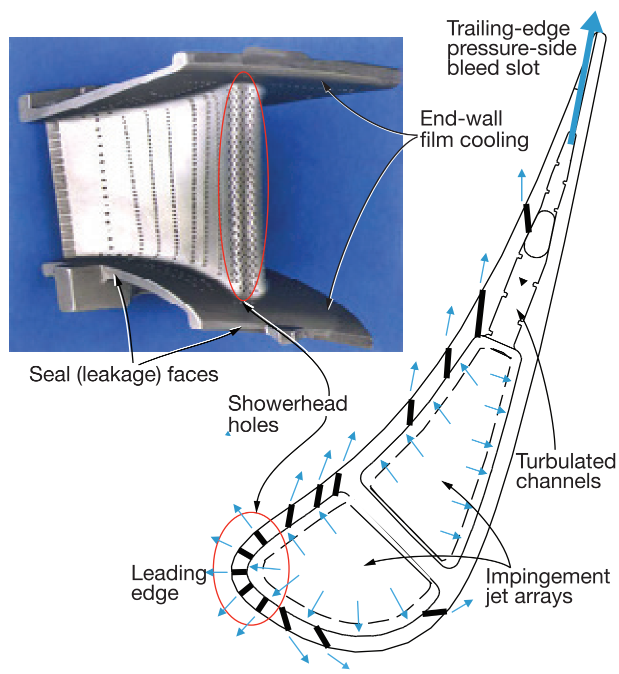

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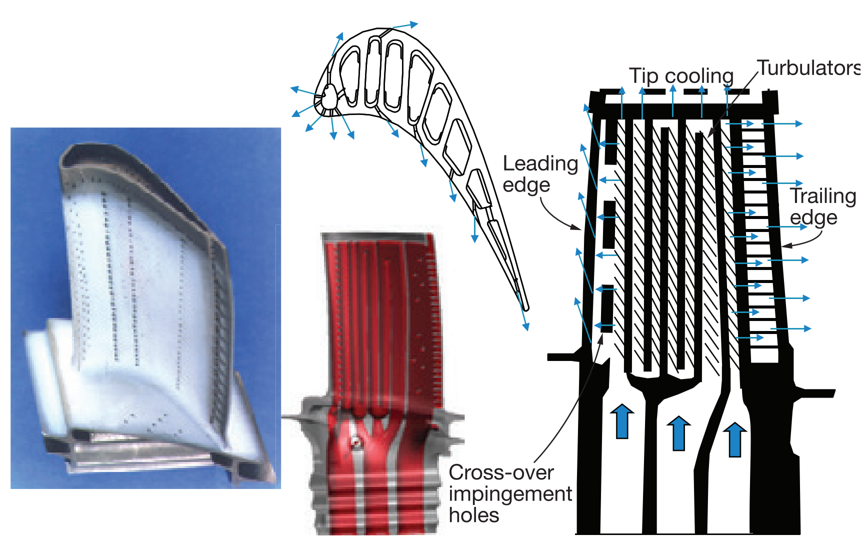

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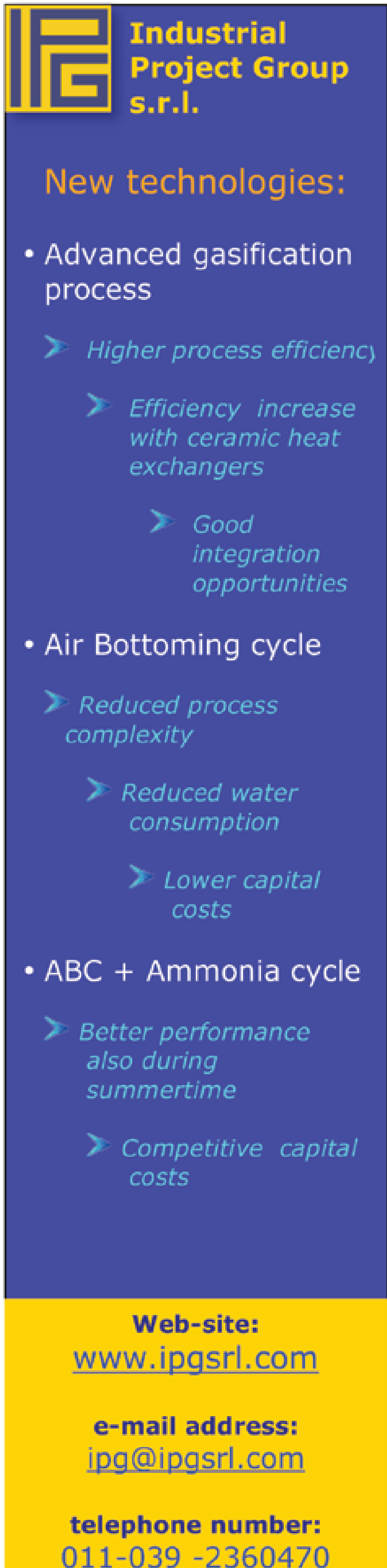

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Outlook. Turbine blade and vane cooling play a key role in making gas turbines for electric-power service more efficient and reliable. These cooling technologies, especially film cooling, will continue to advance gas turbine efficiency and life in the future. CCJ

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Turbine blade, vane cooling—a primer

By Lee S Langston, professor emeritus, UConn

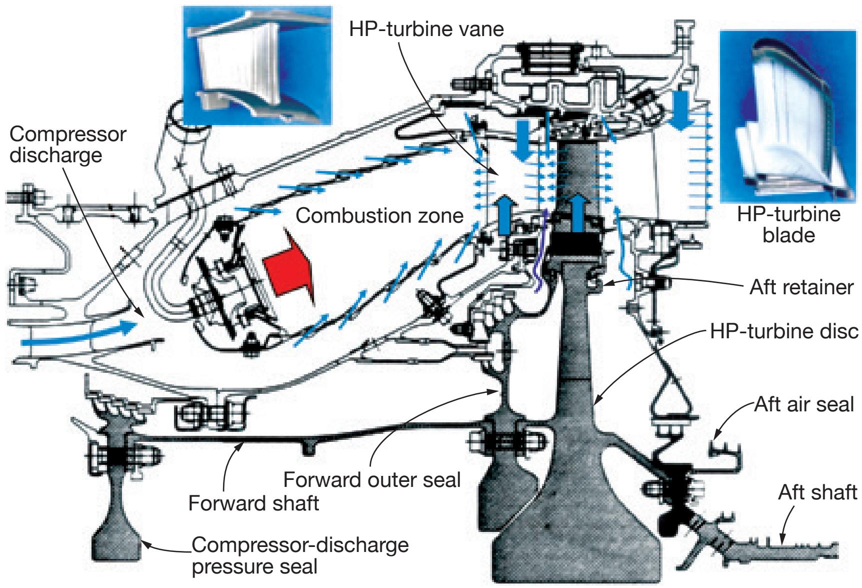
The most efficient powerplants ever produced are now entering service. These latest and largest combined cycles—powered by GE's 7HA, Siemens' SGT6-8000H, and Mitsubishi Hitachi's M501J engines—are all clocking in at 62% - 63% thermal efficiency. This makes them the most efficient heat engines yet perfected by engineers, with all three OEMs striving to reach 65% in coming years.

The gas turbines are state-of-the-art. They make extensive use of turbine blade and vane cooling, thereby allowing the high turbine inlet temperatures required to achieve record-breaking efficiencies. Cooling air drawn from the compressor gas path (as much as 20%) is used to protect hot section parts in both combustors and turbines.

Turbine cooling details. Thermal efficiency increases with the temperature of the gas exiting the combustor and entering the turbine—the work-producing component. Turbine inlet temperatures for modern high-performance commercial jet engines can reach 3000F, while gas turbines in electric-power service typically operate at 2700F or lower and military jets in the neighborhood of 3600F. (The turbine designer must accommodate for excursions above these nominal temperatures, because of combustor hot streaks, etc.)

In the highest-temperature regions of the turbine, special high-melting-point nickel-base-alloy cast blades and vanes are used because of their ability to retain strength and resist hot corrosion at extreme temperatures. These so-called superalloys, when conventionally vacuum cast, soften and melt at temperatures between about 2200F and 2500F.

This means blades and vanes closest to the combustor can be operating at gas-path temperatures far exceeding their melting points. To endure temperatures of 500F to 1400F above melting, they must be cooled to acceptable service temperature (typically eight- to nine-tenths of their lower melting



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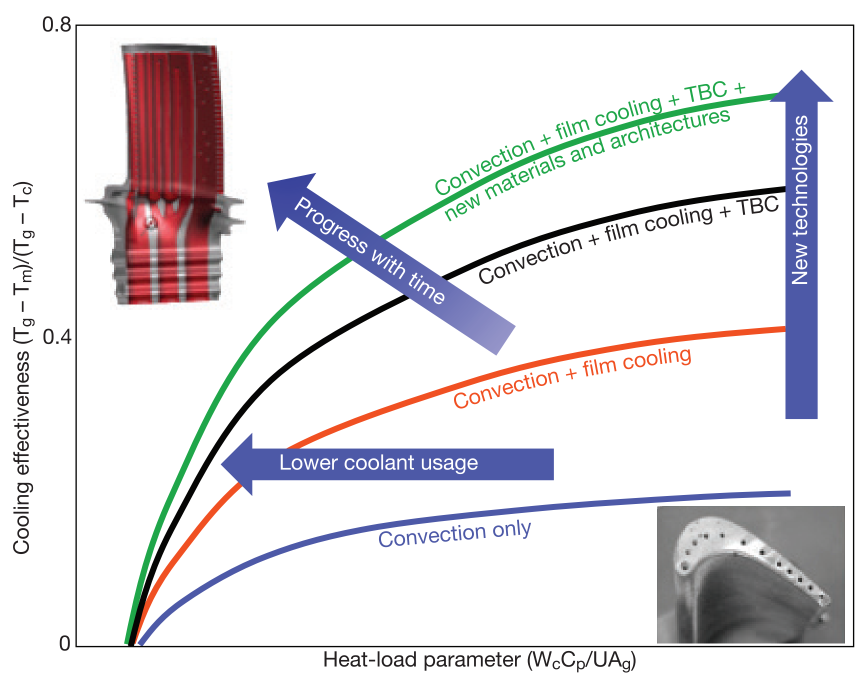

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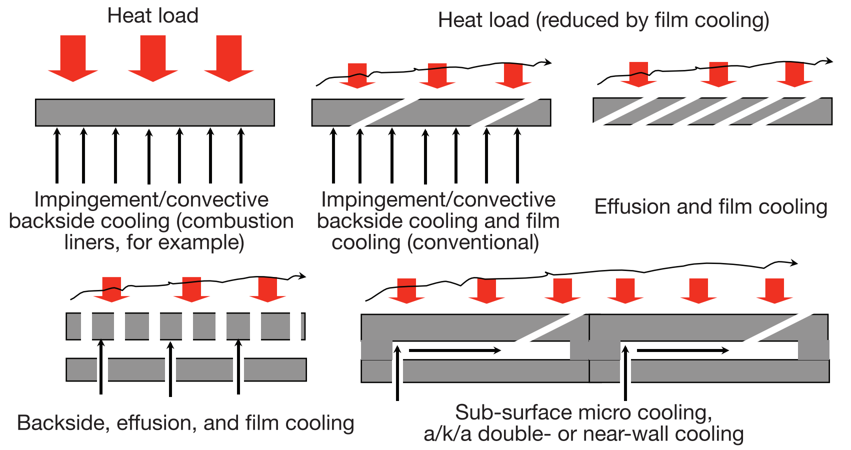

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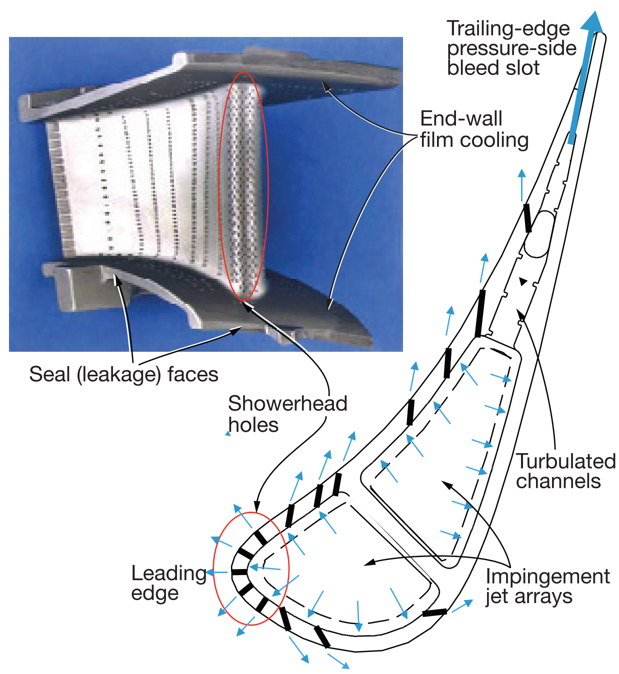

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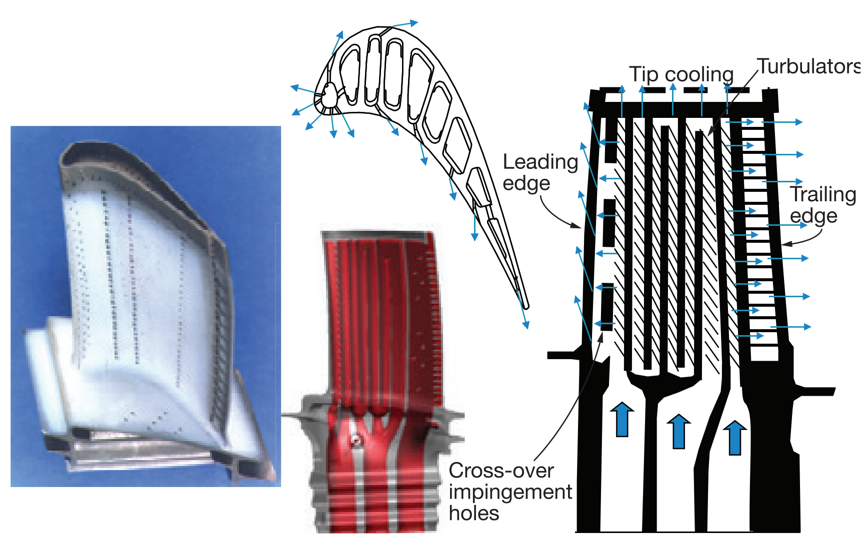

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Performance improvements in fans, heat transfer, water chemistry reflect global effort

By Steven C Stultz, Consulting Editor

The Ninth Annual Meeting of the Air-Cooled Condenser Users Group (ACCUG), held Oct 3 - 5, 2017 in Las Vegas, began with a moment of silence and tribute to the host city and its residents. Las Vegas had just suffered senseless violence directed at the annual country musical festival known as *Route 91 Harvest.* ACCUG participants arrived the following day to experience what quickly became known as *Vegas Strong*—a swift, heroic, and thorough response by the city and its people.

ACCUG17 went ahead as planned. The three-day event featured specifics of performance issues and measurements, equipment challenges and solutions, system chemistry, and design details that could be discussed, shared, and taken home for the benefit of operating plant personnel, owner/operators, and researchers. As you read through the summary below, keep in mind that details are available in the PowerPoints aggregated at www.acc-usersgroup.org.

Looking ahead, planning for the 2018 conference is still in the formative stage. The meeting likely will be held on the East Coast in early fall.

Performance measurement

Huub Hubregtse, ACC Team (Zierikzee, Netherlands), began by explaining that all ACC installations have two distinct performance measurement procedures—one used during commissioning, the other during operation. His presentation focused on the latter.

The operator is interested in the details of ACC performance, and from good measurements can decide what modifications or adjustments might be required. Accurate performance determination depends upon correct online measurement of fan performance, air-side thermal performance, fouling, and leak rate. There is an engineering requirement to then interpret the data.

The plant DCS records turbine backpressure, steam temperature at the turbine exhaust, condensate temperature, extraction temperature, steam flow, and ambient temperature at the weather station. With this information, the *performance calculation method* (a thermal design model) can calculate turbine backpressure as it *should* be. When compared with actual or historical backpressure, differences indicate either performance loss or performance improvement.

Fan performance determination requires the following data:

- Actual air flow from the fan.
- Static pressure in the plenum.
- Static pressure at the suction side of the fan.
- Fan power.

Air-side performance is evaluated based on the temperature rise of the air across the finned heat-exchanger tubes. The hot air temperature is commonly measured at the outlet of the bundles (50 positions). Air flow is measured from the fan bridge in at least four directions.

1. Eskom's Medupi Power Station in South Africa, rated 4764 MW, features the world's largest air-cooled condenser. Three of the plant's six coal-fired units were in commercial operation at the time of the 2017 ACC Users Group meeting in Las Vegas. According to published reports available to the editors, Medupi will achieve full commercial operation in 2020

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ACC fouling has two effects. First, air flow is restricted, resulting in a higher static pressure than the original design. Second, the heat-transfer coefficient of the finned tubes is reduced by *insulation layers* (fouling) on the surface. Thus, ACC performance tests should therefore be made after tube cleaning.

Leak rate has an important impact on performance. If the rate is above the standard leak rate of 0.3 to 0.5 mbar/min, ambient air is entering the ACC. This can reduce heat transfer, and values of 7% to 10% performance loss have been recorded.

Questions and discussions included the impact of *steam quality* on these calculations, technology options available for measuring precise air flow, and measurements at fan inlet versus outlet (access being a significant factor).

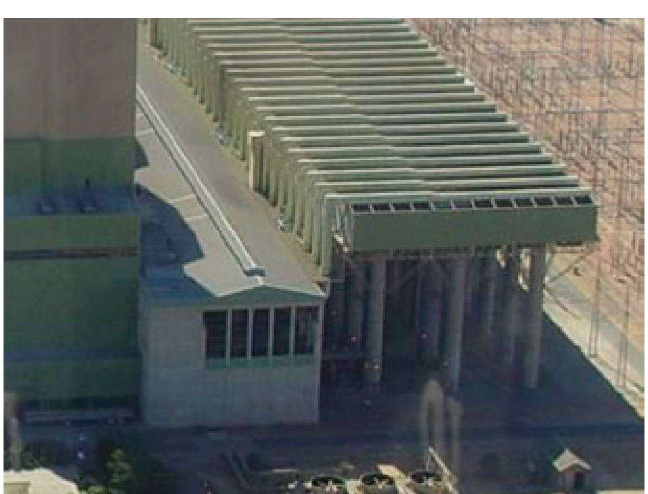
Performance on windy days

At the 2012 ACC Users Group meeting in Gillette, Wyo, Eskom's Johannes Pretorius gave a detailed presentation on how owner/operators develop and implement specifications for large ACCs in South Africa (SA). He also outlined a realistic ambient-air-temperature specification process.

Ockert Augustyn, Eskom, Johannesburg, SA, returned in 2017 to discuss the operating performance—particularly during windy conditions—of the world's largest ACC at Medupi Power Station. Medupi has six 794-MW coal-fired units; three were operating at the time of the meeting (Fig 1).

Eskom, which produces about 95% of South Africa's electricity, operates large ACCs at four multi-unit installations. Fans measuring 30 ft in diameter number between 48 and 64 per condenser; platform heights are 145 to 195 ft. Water restrictions dictate use of ACCs.

Augustyn stressed that all ACC performance requirements are specified by the purchaser; the supplier is responsible for compliance and




2. The Matimba Power Station's ACC (left) provided valuable lessons learned for the nearby Medupi (right)—especially regarding site layout, fan height, and wind walls

3. The at-grade wind walls at Medupi (photo) were extended from Matimba's 33 ft to 47 ft

4. Hail screens were installed at Yellowstone Energy LP's Billings (Mont) Plant to protect finned heat-transfer surface

design. However, repeating the message from 2012, the supplier can be at an advantage because performance testing is not conducted at high-wind conditions.

He then outlined the risks for the purchaser (Eskom). A supplier could be reluctant to add safety margins or other features that would render their offering less competitive, and the purchaser may not be able to disqualify offers or justify higher costs if all suppliers meet the specification. More important, performance characteristics in windy conditions are essentially unknown until after commissioning (too late for design changes).

Because most suppliers are in compliance with specifications, the advantage is theirs, and the purchaser needs to be knowledgeable of all potential risks and limitations.

Operational experience for Eskom shows significant capacity loss during adverse weather conditions (high temperature and high wind speed, in particular). At the older Matimba site, CODs of its six 665-MW units extended from 1988 to 1993 (Fig 2); 12 vacuum-related unit trips attributed to wind occurred during the first seven years of operation. In 2016 alone, there were multiple cases of load losses exceeding 1000 MW.

Planning for Medupi drew upon Eskom's experience at Matimba and other plants:

- Atmospheric conditions were based on 130-ft elevation above grade.
- Design wind speed was 20 mph in any direction.
- Wind wall height was extended to the top of the steam duct.
- An 8-ft-wide solid walkway was placed around the entire platform perimeter (for maintenance work, but also to reduce hot air recirculation).
- Wind cross on ground level was 33% of fan inlet height.
- Performance guarantees were verified by CFD before construction.

Also required was an increased gap (165 ft) between the ACC and turbine building (compare Figs 1 and 2).

The at-grade wind walls at Medupi were extended from Matimba's 33 ft to 47 ft (Fig 3).

Augustyn explained: "We went with what we knew, then made things stronger and bigger."

Medupi entered commercial operation in October 2015 and has experienced no vacuum-related load losses. ACC performance comparisons of Medupi and Matimba benefit from proximity of the two plants. Eskom representatives would return later.

Hailstorms

Moving away from South African heat, Dan Burns, Burns Engineering Services (Minnetonka, Minn) presented "Protecting an air-cooled condenser from hail damage," referencing a patent-pending system at the Yellowstone Power Plant in Billings, Mont.

Yellowstone is a two-unit coke-fired plant with an ACC commissioned in 1995 having two streets and 10 cells.

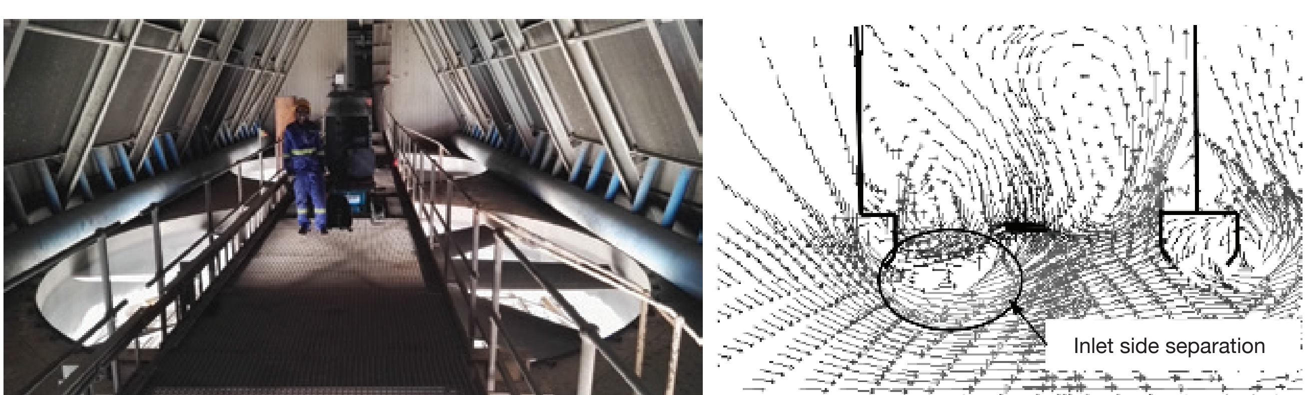
A major hailstorm hit the area on May 18, 2014, with hail up to 2.5 in. diameter. Severe damage occurred to the finned surface areas. Dented fins restrict air flow and thus reduce heat-exchange capability.

The protective material selected was standard SS316L metal wire screen, tensioned over a support structure (Fig 4). Screens were placed above the steam distribution duct at 75 ft above grade and on the perimeter.

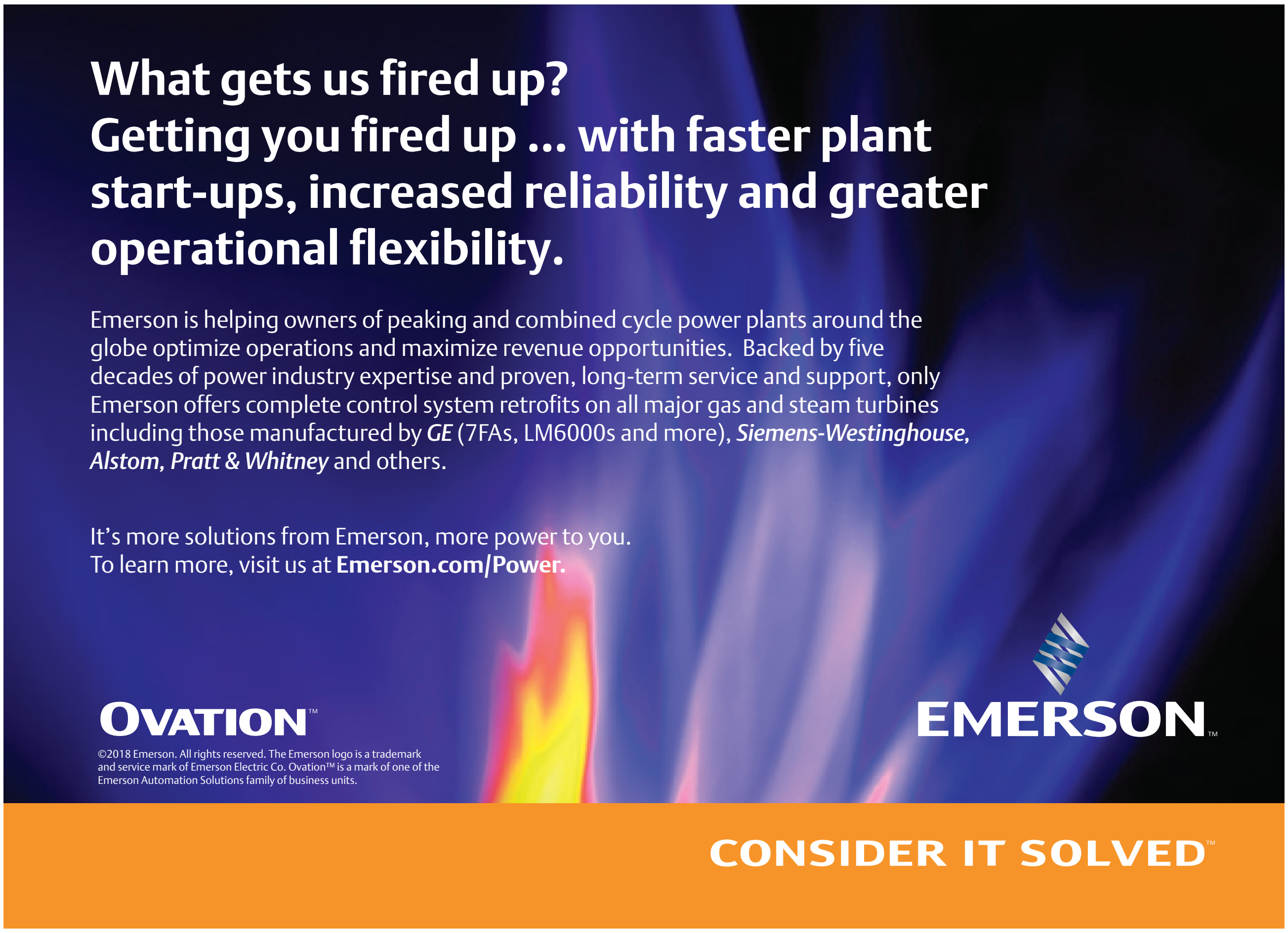
Discussion topics included material options, angle of hail attack, cost, and opening size versus hail buildup.

Dynamic response

Danie Els of South Africa's Stellenbosch University, presented "Dynamic response of ACC fans," describing precise details of onsite measurements for blade and shaft loading, laboratory analysis of vibration sources, and simulations of fan-system dynamics



5. Understanding fan-system dynamics is an important first step in ACC performance optimization. Onsite measurements at one of South Africa's six-unit stations were critical to analyses of actual blade and shaft loads. At left, note that the fans are suspended from a bridge that runs through the ACC. Sketch, right, illustrates the distorted inlet air-flow conditions experienced by one fan which were caused by winds and other fans, plus the downstream flow obstruction (bridge)



(response versus design).

Els began by explaining distorted inlet airflow conditions caused both by winds and the influence of other fans, as well as common downstream flow obstructions (Fig 5).

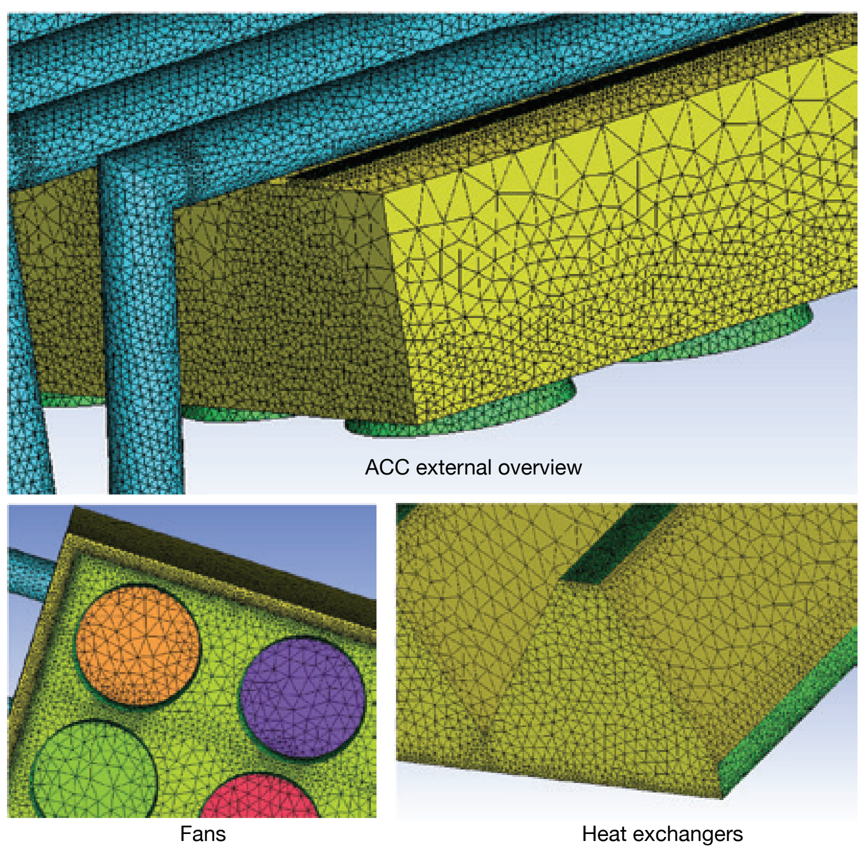
He followed with blade-loading measurement details including fan location within the ACC and spatial relationship to boiler and generator hall, followed by wind speed, wind direction, and vibration frequencies. Laboratory analysis looked at the effect of the fan bridge on fan-blade vibration, using variables of flow rate, distance between fan rotor and bridge, and bridge solidity.

Details of shaft bending versus wind direction followed. Matimba was used as a reference plant.

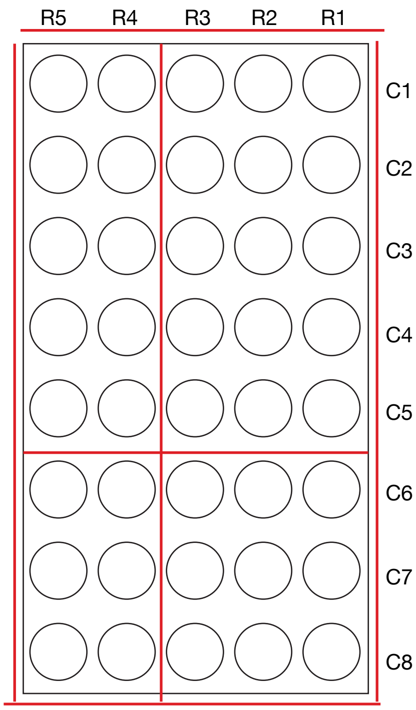
Wind screen design by CFD

Cosimo Bianchini, a CFD specialist at Italy's Ergon Research had participated in 2016 by video link from Italy. He was on location in Las Vegas to enhance both detail and discussion on CFD modeling of wind screens.

His presentation "CFD analysis for optimal wind-screen positioning" began with the basics: powerplant performance can be affected by wind's impact on the ACC, reducing net power by 10% or more for each 22 mph of wind.



6. Geometric modeling using CFD reproduced the 3D local air field around the ACC with sub-modules for fans and heat exchangers



7. Optimal configuration and location of the wind screen reflects a compromise between performance and simplicity (cost)

8. MEA/Anodamine treatment mitigated upper-duct corrosion found during the 2011 inspection (left). Photo at right was taken in 2016

Two common sources of wind-induced ACC losses are fan performance degradation and recirculation of hot air into downwind fan inlets.

Bianchini outlined the overall modeling strategy:

- Reproduce the 3D local air field around the ACC using CFD.
- To maintain computational costs within reason, do the following:
  - Assume constant wind magnitude and direction.
  - Assume other plant systems operate at nominal conditions.
  - Include active CFD sub-modules for fans, heat exchangers, and wind screens.

The test case presented was an ACC of five streets (eight fans each) partially surrounded by tanks and buildings. Fan diameter was 38 ft, deck elevation 65 ft.

Geometric modeling (Fig 6) used an unstructured hybrid grid (total of 10,000 cells):

- Tetrahedral elements were used to model the free-stream.
- Prismatic cells were used to better define the boundary layer.
- Many solid walls were treated as thin surfaces:
  - Most ACC walls are solid.
  - Fan and bundle surfaces (fan model and radiator model).
  - Wind screens and lifting devices (pressure-jump model).

One advantage of modeling is the ability to test variations. In this case, 11 mitigation devices (screen plans) were tested by combining various suspended and ground designs. The optimal configuration, a compromise between performance and cost, was the cruciform fabric screen (30% open area) and suspended vertical screens around the ACC walls (Fig 7).

The conclusions: wind screens can mitigate wind losses, showing a gain of up to 14% at 22 mph. This *recovery factor* starts decreasing at intermediate wind speeds. Actual flow rate depends on wind-screen configuration, wind speed, and wind direction.

Chemistry and corrosion

Barry Dooley launched the second day with an update on cycle chemistry and flow-accelerated corrosion (FAC) damage, offering a world view for all ACC designs and all chemistries. Last year the presentation highlighted inspection, and understanding the resulting data.

Dooley, a member of the steering committee, again stressed that the relationship between total iron and pH is consistent worldwide, and corrosion results in elevated iron levels. High concentrations of iron within the cycle lead to HRSG deposits (and expensive chemical cleaning), tube failures (including overheating), and potentially steam-turbine deposits. He repeated, "Overall, an ACC controls unit cycle chemistry."

He reviewed the Dooley/Howell Air-Cooled Condenser Corrosion Index (DHACI) with specific visual examples. (See section on Comanche 3 below.)

Dooley stressed the importance of investigating for "holes in the tubing or welding" at tube entries.

He then offered a list and status of current solutions for FAC:

- Increase bulk condensate pH up to 9.8 with ammonia: Effectiveness has been validated.
- Increase local pH with neutralizing amines: Appears effective.
- Add film-forming products: Appears to work but the science is incomplete.
- Use filters and condensate polishers: Can lower iron transport but does not stop FAC.
- Add coatings, sleeves, inserts: Insufficient information.
- Convert to alternative materials: Rare, no validation.
- Change the design: Designs vary, but FAC still occurs.

He also stressed that, even with proper chemistry changes, damage takes time to repair (using examples of 18 and 24 months).

Dooley ended with a complete review of Technical Guidance Documents available for fossil-fired steam and combined-cycle plants available free of charge through iapws.org. His final thoughts:

1. Increasing condensate pH to 9.8 gradually eliminates the FAC damage at the tube entries and iron levels will reduce to IAPWS-suggested levels of 5 to 10 ppb.
2. Damage on cross members is not repaired as quickly by increasing pH because the mechanism of metal loss appears to be different.

ACC corrosion

Bill Stroman, KAAM Group Inc, Carlsbad, Calif, followed Dooley with "Chemistry options to address FAC-like corrosion." The subject was two identical ACC-equipped 1 × 1 combined cycles. Because of "the cost of scaffolding," the upper ducts had not been inspected since commissioning (11 years).

At present, Unit A operates intermittently; Unit B is primarily baseload but beginning to cycle. During a recent inspection, FAC-like corrosion was noted in the upper ducts and transition duct.

Based on experience with other generating stations, Plant A operators switched to MEA (monoethanolamine) treatment in 2012, then due to cycling switched to an MEA/Anodamine filming program in 2013 (to improve offline protection). ACC upper duct inspection showed improvements (Fig 8) after the change. Inlet vanes showed similar improvement. Duct

inspection also showed water beading (hydrophobicity) from the Anodamine treatment (Fig 9).

Plant B also showed ACC improvements although it remained with the ammonia MEA treatment program. One significant improvement was the steam turbine expansion joint protective shroud (Fig 10).

Comanche 3 hybrid

Andy Howell, Electric Power Research Institute, and chairman, ACC Users Group, presented a seven-year status report of the ACC in the hybrid wet/dry cooling system at Xcel's Comanche Station Unit 3. The 750-MW supercritical coal-fired unit began commercial operation in 2010.

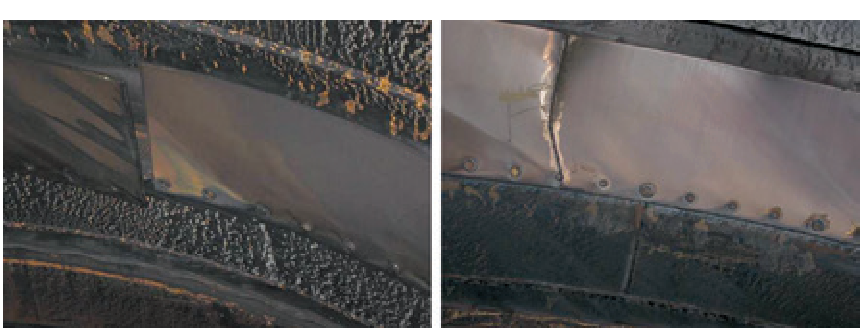
System pH has been maintained between 9.45 and 9.60 with ammonium hydroxide; iron is less than 0.3 ppb at the economizer inlet and 1 to 3 ppb at the high-pressure heater drain. Internal ACC inspections were conducted at 14, 50, and 81 months.

The presentation provided a valuable backgrounder on the Dooley-Howell ACC Corrosion Index rating system and ACC.01, "Guidelines for internal inspection of air-cooled condensers" developed by the ACC Users Group and available at www.acc-usersgroup.org/reports.

Conclusions for this presentation were:

- ACC tube inlet corrosion has been inconsistent while steam-cycle chemistry has appeared to be consistent, and
- Options for evaluating tube corrosion, such as thickness testing and corrosion coupons, have been implemented at Comanche 3 and may prove useful.

9. Duct inspection showed water beading from the Anodamine treatment at the tube inlet (left) and on the lower-duct metal surface (right)



10. Protective shroud for the steam-turbine expansion joint was found in better condition in 2016 after MEA treatment (right) than it was in 2011 (left)

Gearbox design

Chad Brown, engineering manager, Amarillo Gear Co, Amarillo, Tex, discussed "Reliability in an ACC gearbox: from a designer's perspective." His agenda covered standards, application considerations, and serviceability.

Brown began with the written standards, developed in a consensus-based

process to clearly describe required characteristics. Such standards set the baselines, promote efficiency and quality, and safeguard people and equipment.

Among the standards discussed were those endorsed by the American Gear Manufacturers Assn (AGMA), International Organization for Standardization (ISO), and German Institute for Standardization (DIN).

"One key," stated Brown, "is to know that there are differences, and that one standard is not necessarily better or worse than the other. But it is important to understand the variances." In one example, he listed an AGMA example as "empirical, based on experience" and the ISO counterpart as "theoretical, based on academia."

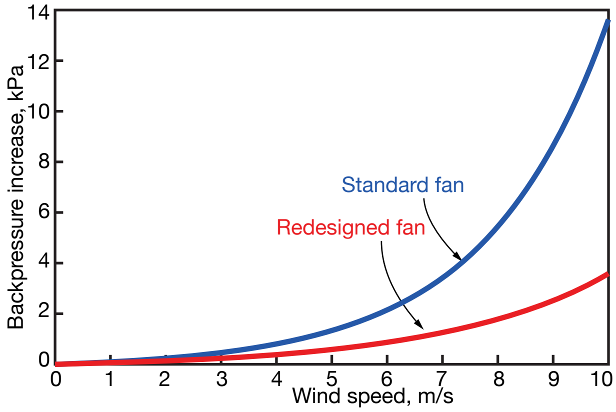
He then offered an in-depth look into CTI Standard-167, "Gear speed reducers for application on air-cooled condensers," issued in 2017 by the Cooling Technology Institute.

Brown was not promoting his company; he was promoting quality and standards. His conclusions:

1. Understand the hierarchy of standards to your advantage when designing and selecting a gearbox for air-cooled condenser use. Remember: Different standards yield different results.
2. CTI STD-167 should be used to provide the highest reliability in an ACC application. It "levels the playing field," suggested Brown.
3. ACC gearboxes face unique challenges that need to be understood and addressed by the owner/operator, plant engineer/constructor, ACC OEM, and gearbox manufacturer to ensure maximum reliability.

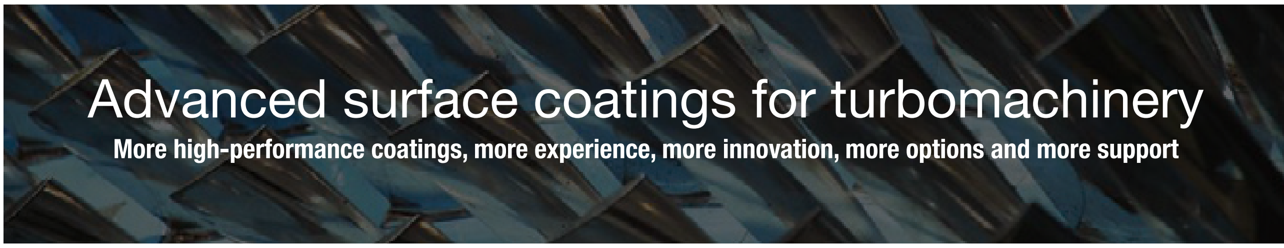
Gearboxes in South Africa

Augustyn returned to discuss Eskom's 20 years of gearbox experience in the large South African units. Within its ACC fleet, Eskom has various gearbox configurations with a wide range of problems, remedies, and alternatives.



11. A low-profile hoist and associated rigging was needed to install new gearboxes at NV Energy's Frank A Tracy Generating Station (above)

12. Fan design improvements provided by a global consortium for Eskom dramatically reduced ACC backpressure on windy days (left)



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The utility operates nine different types of gearboxes from three manufacturers. Its gearbox population exceeds 1200.

Casing types are both mono and split. Lubrication is both splash and force-feed. Oil is both mineral and synthetic. Fan bridge layouts differ.

An interesting note was a plan to leave grating open space (around the gearbox) for maintenance. His point: "If you are 190 ft above grade, it's 115F ambient, and you ask someone to temporarily remove some grating, it probably won't be put back."

Eskom is also considering direct-drive gearboxes (the industry's first is now operational at Dry Fork Station in Wyoming).

Gearboxes at Tracy

Sean Berryman, maintenance manager, followed with a review of gearbox experience at NV Energy's Frank A Tracy Generating Station. The plant's 2 × 1 F-class combined cycle is a 541-MW load-following unit operating at 96% equivalent availability and providing 35% of Northern Nevada's energy needs. This includes an ACC with 30 fans arranged in six streets. Fans are rated at 250 hp, and gearboxes at 500 hp. All fans are required during summer operation.

Historical gearbox failure has been 15% to 25% (2011 to 2017).

Moving forward, 20 new 750-hp gearboxes will be installed. This will require larger hoists (3 tons versus 2) and low-profile hoist/rigging to lift the new boxes over the motors (Fig 11).

As an aid to not only maintenance time but to employees, a rack-and pinion-elevator has been installed. Another site innovation is online oil filtering of gearbox sumps using a hand-held, operator-friendly system.

Tube cleaning

Romain Pennel, a director at AX Systems, Bailleul, France, presented on a cleaning system created in France in 2008 by Miroslaw Glusko.

Pennel began with an overview of fouling mechanisms, showing how they create an isolation film and limit air flow through the fins, thereby reducing heat transfer. This includes fouling from the natural environment (such as pollen or sand) and from industrial sources (fiber, dust, and oil). The result: Reductions in vacuum, turbine steam flow, and power generation.

ACC configurations covered in the presenter's discussion of cleaning systems and challenges included flat, A-frame and V-frame.

Examples of what *not* to do with regard to external cleaning of heat-transfer surfaces included the following:

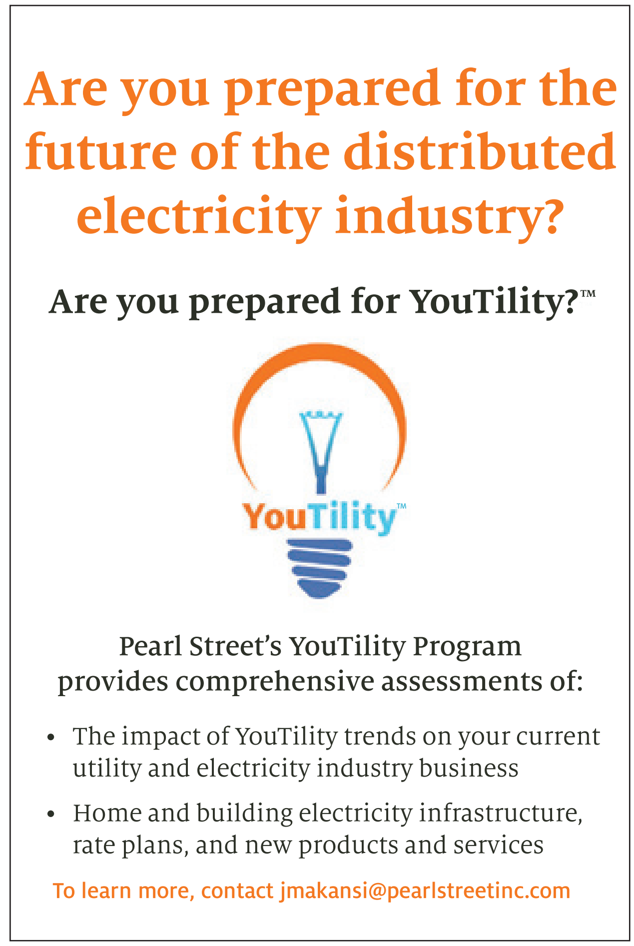
- Don't use manual high-pressure spray equipment: It's easy to bend fins when the spray head is not perpendicular to the tube surface.
- Avoid sandblasting. Risks include fin damage and removal of any tube coating—aluminum, for example.
- Say "no" to use of a bicarbonate solution for cleaning. Risk is the electrolysis effect between aluminum and $NaHCO_3$

A case study was presented on a 29-MW waste-to-energy plant in the UK, commissioned in 2014 with two A-frame ACCs. Power had dropped to 26 MW and vacuum to 0.7 bar, suggesting the need for cleaning. Post-cleaning results showed vacuum at 0.9 bar and power at 28.29 MW.

Tube-cleaning document

Andy Howell followed with a status on the planned ACC Users Group document ACC.02, "Finned tube heat exchanger tube cleaning." The current outline for the document is below:

- Operational factors limiting ACC efficiency.
  - Ambient temperature.
  - External tube fouling.
- Foulant removal.
  - Water.
  - Air.



13. Solar-powered steam generators at Ivanpah, the world's largest concentrated solar thermal facility rely on ACCs

14. Walter M Higgins Generating Station has contributed significantly to industry knowledge on the behavior, operation, and maintenance of air-cooled condensers. Owner NV Energy was the driving force behind the formation of the ACC Users Group and held the organization's first meeting at its headquarters building. Solar array in background adds to the site's generating capability

- Carbon dioxide (dry ice) pellets.

- Frequency of finned-tube cleaning.
- Implementing the cleaning process.
- Tubing structural/operational inefficiency issues.
- Safety and environmental.
- Conclusions.
- References.

All participants (and CCJ subscribers) are invited and encouraged to participate with suggestions, reviews, and comments.

Ultra-efficient fan design

Participants returned again to the Matimba ACC in South Africa. At the time of construction, this unit was the largest ACC in operation anywhere in the world (3690 MW in 2001). Eskom has firmly established itself as a "world leader in dry-cooling technology."

The plant has also suffered historic losses, specifically in windy months. But it is not economically feasible to reduce load losses entirely. Typical annual production is 24,000 GWh. Vacuum-related losses in 2016 were 350,000 MWh, or less than 1.5% of total production. "Economics make it difficult to find a solution that justifies the capital expenditure without the guarantee of total load-loss reduction," explained Augustyn.

Eskom conducted a thorough review

of previous CFD work, including placement of wind screens. This led to a detailed review of fan performance.

Aerodynamic design was reviewed with CFD, keeping the same duty point. Static efficiency was set at 60%, and a *steep curve* was established to protect against wind. Stellenbosch Univ became involved. A consortium was established to design, manufacture, install and commission a 30-ft-diam fan. Consortium members included Kelvion (Germany), Enexio (Germany), ECILIMP Termosolar (Spain), Soltigua™ (Italy), IRESEN (Morocco), Waterleau Group NV (Netherlands), and Notus Fan Engineering (South Africa).

A unique manufacturing process offered consistent weight distribution and a repeatable infusion process. When eight blades were weight-tested, there was only a 500-g difference (less than 1%). There also was a 50% weight reduction with the new design.

Blade angle settings achieved increased volume flow and reduced fan power consumption.

A striking benefit was improvement in turbine backpressure vs. wind speed (Fig 12).

Aerodynamic improvements:

- New fan consumes 15% to 20% less power for similar flow displacement.
- Volume flow rates can be increased by 10% to 20%.
- Cells have greater protection against wind effects.

Structural improvements:

- Blades are not resonating (vibrational loads on gearbox greatly reduced).
- Fan blade weight is reduced by 50%.
- Blade shape and structure are consistent (interchangeable blades).

Funding was provided by the European Union through its Horizon 2020 Research and Innovation Program.

Air in-leakage

Oscar Hernandez, InterGen, a member of the steering committee, offered details on air in-leakage at three ACCs in Mexico and two in the UK.

At one plant in Mexico, accurate online instrumentation detected a change in dissolved oxygen concentration leading to repair of a spray nozzle. In another, dissolved oxygen again triggered an investigation leading to a steam-turbine gland seal out of position. For both, credit was given to accurate online instrumentation and continuous chemistry monitoring.

A lengthy list of key indicators beyond chemical parameters was reviewed, highlighting such items as increase in backpressure, decrease in condensate temperature, and loss of ACC vacuum. This was followed by a list of common air in-leakage sources including missing hardware, penetrations, welds, turbine shaft seals, expansion joints, pump seals, manways, and valves. Thermal imaging was recommended, looking for *black spots*.

IAPWS is reviewing the subject of air in-leakage for a new Technical Guidance Document planned for 2018.

Ivanpah and Higgins

On the final day, participants were offered tours of two facilities: the Ivanpah Solar Thermal Plant and the 2 × 1 combined cycle Walter M Higgins Generating Station.

Kristen Pogozelski, who is leading optimization efforts for Ivanpah's liquid ring vacuum pumps (LRVPs), addressed the participants on Day One.

Each of the three solar thermal steam generators at Ivanpah (Fig 13) has a three-street ACC with five fans per street. The facility was commissioned in 2013.

Units have been showing reduced vacuum, impacting megawatt production. Helium testing found leaks in the main boiler feed pumps, turbine bearing gland, steam supply line, and at several areas in the vacuum pump skids. The main target became the liquid ring vacuum pumps.

Laura Sterk, NRG Energy, gave an overview of Ivanpah to orient attendees for the plant tour.

At Higgins (Fig 14), the summer peak is about 530 MW. Operational since 2004, the plant has continually performed in the top 10% of combined-cycle plants in the US with a 99% availability, according to NV Energy's Dave Rettke, NV Energy, a member of the ACCUG steering committee. Rettke conducted the tour.

Dry cooling enables Higgins to make the same amount of electricity with only 7% of the water used by a comparable conventional water-cooled facility. The plant's ACC has eight streets, each with five 30-ft-diam fans.

Inspection and maintenance are keys to success at Higgins. The site conducts thorough weekly walkdowns of all equipment, recording all observations. As Rettke explained, "It's important to see an ACC as a *live structure* under the influences of wind, vibration, and thermal changes."

Many unique procedures and tools have been developed by Higgins personnel. Ongoing vigilant observation by site personnel has allowed the plant to maintain high availability, even while it has moved from base-load to cycling operation. CCJ

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How does PAG stack up against mineral oils after a decade of experience?

An increasing number of turbine owner/operators suffering varnish issues associated with the use of mineral-oil lubricants has been migrating to non-varnishing polyalkylene glycol (PAG) over the last decade (see sidebar for a chemistry refresher).

EcoSafe® TF-25, based on a PAG formulation developed by Dow Chemical Co and marketed exclusively by American Chemical Technologies Inc (ACT), continues to attract converts—most notably among the industry's shrinking pool of experienced engineers responsible for the care of gas and steam turbines.

New-product introductions in the electric-power industry are notoriously difficult given the unwritten code that warns against being the first to try a new product. The typical response: "No Number Ones!" Generally there is little, if any, upside for users taking such risk.

EcoSafe TF-25 gained a toehold 10 years ago at two combined cycles powered by 7FA gas turbines experiencing expensive random trips attributed to varnish. In the seven years following the product's powerplant debut in November 2007, 50 turbines, in round numbers, had converted to PAG from mineral oil. It took only three more years to convert another 50 units. Momentum continues to build.

Does this trend suggest mineral oils might be a superannuated lubricant for turbine service? No. Or, that there are no effective methods for removing varnish from mineral oils? No. What you will learn from the two 10-year case histories summarized below is that EcoSafe TF-25 was an effective solution at these locations given their specific conditions, and something you might consider under similar circumstances.

Tests conducted at both generating plants after a decade of service suggest the expected useful life of EcoSafe TF-25 is in the neighborhood of 35 years. Might a judiciously selected and properly maintained mineral oil last as long? Some experts say it's possible.

Consider attending the upcoming meeting of the Steam Turbine Users Group (STUG, www.stusers.org), Aug 27-30, 2018, in Louisville, to become more knowledgeable about the properties of turbine fluids and their care. You'll have the opportunity to learn about such things as (1) sampling best practices for accurately tracking the condition of your fluid to assure its proper maintenance, (2) the forgiving nature of PAG with respect to water intrusion—often overlooked—which is a primary cause of mineral-oil degradation in steam turbines, etc.

Northeastern Station, Oologah, Okla, was the first powerplant to convert from mineral oil to EcoSafe TF-25. The 7FA known as Unit 1 in its 2 × 1 baseload, must-run combined cycle made the switch in November 2007, Unit 2 the following March. Reason: In 2005, about four years after commissioning, the gas turbines began experiencing seemingly random trips due to "loss of flame," a somewhat generic condition with several possible root causes.

Investigation of operating data indicated the fuel-gas control valves were not functioning properly. A physical inspection of the hydraulic control circuits found that a tenacious gummy material, later identified as varnish, had been depositing throughout the lube and hydraulic systems. When it collected in servo valves, the varnish caused fuel valves controlled by the servos to misoperate, restricting fuel flow and causing the random turbine trips. In 2007, the plant tripped about 50 times (three times in one weekend alone) and suffered 18 servo failures, according to plant personnel.

Plant management sought a non-varnishing lubricant after speaking with colleagues dealing with varnish issues who advised that seemingly practical "solutions"—such as heat tracing, oil conditioners, some varnish mitigation equipment, etc—would likely be ineffective. Personnel at a sister plant recommended contacting ACT having had success with PAG chemistry in steam-turbine hydraulic systems. Good suggestion.

In relatively little time, system-wide varnish deposits were returned into solution because of the inherent detergency and solubilizing characteristics of EcoSafe TF-25. Subsequent inspections of servos, now serviced every three to five years, and the lube and hydraulic systems have shown them varnish-free. The bottom line: Since conversion to PAG, the gas turbines have not tripped because of a varnish-related problem.

A goal of the battery of tests conducted on the 10-year-old fluid was to determine its remaining life. According to the OEM's gas turbine lubricant recommendations document, GEK 32568h, a turbine oil/fluid should operate trouble-free until its antioxidant (AO) level drops to 25% of the new value. High-performance liquid chromatography was used to determine the AO content in Northeastern's turbine fluid. It calculated the plant's AO loss at 1.99% annually meaning an expected life of 37.7 years.

Tests also revealed the decade-old fluid had the same lubricity and load-carrying capability as new fluid. A mini-traction machine was used to measure both sliding and rolling frictional forces.

Unit 4 at Oneta Energy Center, Broken Arrow, Okla, one of four 7FAs that power the facility's two 2 × 1 combined cycles, also was converted to TF-25 in November 2007 when what was later identified as varnish inhibited operation of the gas turbine's inlet guide vanes. Result: The unit would not start.

In the 10 years since converting to PAG (about 41,000 fired hours and 1500 starts later), plant staff reports EcoSafe TF-25 has performed flawlessly. Tests suggest the fluid should last an additional 20 years. CCJ

Chemistry backgrounder

The stress experienced by a turbine lubricant contributes significantly to the ageing of petroleum oil, causing the *non-polar* fluid to oxidize. However, the resulting byproducts of decomposition are *polar* and insoluble in the base oil; they come out of solution as varnish. Polyalkylene glycol, by contrast, is a *polar* fluid and, while it too oxidizes, the byproducts of decomposition are *polar* and infinitely soluble in the base stock. No varnish is produced.

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Pictured on Left:

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1. Rotor restacking

2. Repair/rebuild of exhaust sections is a significant part of DTS's 501F work today

3. Who's Who at Doosan Turbomachinery Services: Glenn Turner, VP engineering; Keith Bosheers, VP sales and marketing; Matt Lau, VP operations; Billy Coleman, president and CEO; Jaekap Kim, CSO; Kerry McGuire, CFO; Dion Beckner, sales manager. The senior management team combined has well over a century of relevant gas-turbine experience

In today's topsy-turvy world of electric-power generation and delivery anything can happen, and it does. Recall that only a couple of years ago, the OEM with the largest position in the generation sector purchased a major competitor and tried to take by storm the industry's aftermarket business—worldwide. That might have led some to conclude that other companies would shy away from investments in outage, maintenance, and repair activities and there would be fewer options for powerplant owner/operators.

Not true. One example: Doosan Heavy Industries & Construction Co (Doosan), a 123-year-old company with deep ties in power generation, purchased privately held ACT Independent Turbo Services July 26, 2017, renaming it Doosan Turbomachinery Services (DTS) and establishing an aftermarket presence in North America to serve the world. The Korean firm did not have a formal gas-turbine repair group before acquiring ACT.

Doosan had a small footprint in the North American electric-power market at the time, which is why you might not be familiar with the company. But it has been a force in Asia, Europe and the Middle East for decades. Doosan may have been best known here for its fossil-fired boiler and combustion systems expertise and products gained through the company's acquisition of Mitsui's Babcock Energy Ltd in 2006.

More than 90% of Doosan's \$16.4-billion revenue stream (2016) is generated by its infrastructure support activities divided among six business groups: EPC, turbine/generator (Sidebar 1), nuclear, power service, water, and castings and forgings. Doosan Turbomachinery Services reports directly to James Kim, director of the gas-turbine business unit in the turbine/generator business group.

Gas turbines. Doosan has a gas-turbine manufacturing history that dates back to 1991, when it was licensed by GE. In 2007, it also was licensed to produce gas turbines by Mitsubishi Hitachi Power Systems (Sidebar 2).

Today the company is transforming itself into an OEM, expecting to introduce a 270-MW (60 Hz) engine to owner/operators in 2022. Full-scale/full-load tests are scheduled for mid-2019 to mid-2020 in Doosan's Changwon (Korea) manufacturing facility. Development of a 340-MW (60 Hz) H-class engine is well underway with design completion anticipated about a year after commercial introduction of the F-class machine. Previously the company developed and tested a 5-MW gas turbine/generator which was offered commercially in 2009.

Changwon is an "A to Z" manufacturing facility for gas turbines, as it is for steamers, handling everything from the production of producing castings and forgings through engine assembly and testing. A big plus for gas-turbine customers is the facility's capability in the manufacture of turbine and compressor discs for all legacy engines. Inconel discs are under development.

Changwon's hot-parts shop, equipped for manufacturing and repairs, does coatings, heat treatment, machining, welding, inspection, etc. The full-speed/full-load test rig has more than 3000 sensors to verify gas-turbine operational stability, structural integrity, and performance.

DTS, which opened its doors as Advanced Combustion Technology in 1996, expanded dramatically in both size and capability in the second decade of the new millennium and today has a global footprint among the industry's leaders in aftermarket gas-turbine services (Sidebar 3).

Industrial gas turbine (IGT) component repairs were the company's bread-and-butter until 2012. The editors vis-

1. Turbine/generator development highlights

Doosan was a pioneer in the development of steam turbine/generators, its work in the field dating back 114 years. The company has supplied more than 650 units worldwide (about half of those in Europe) for conventional fossil-fired steam plants, combined cycles, nuclear, etc, with a combined capability of more than 130,000 MW (about half that total in Asia). Milestones include the following:

- 1904—first steam turbine/generator, rated 412 kW.
- 1932—first reheat unit.
- 1965—200-MW reheat unit.
- 1976—200-MW nuclear unit.
- 1977—500-MW subcritical unit.
- 1991—1000-MW nuclear unit.
- 1993—500-MW supercritical unit.
- 2005—500-MW ultra-supercritical unit (3625 psig/1050F/1100F).
- 2007—700-MW supercritical unit, 1450-MW nuclear unit.
- 2013—1000-MW ultra-supercritical unit.

Today Doosan manufactures steam turbines and generators, and excitation and control systems, for industrial and utility customers with ratings up to 1500 MW (50 and 60 Hz), plus supporting Rankine cycle equipment (condensers and heat exchangers). Manufacturing centers are located in Changwon, Korea, and Doosan Skoda Power in Plzen (A/K/A Pilsen), Czech Republic. Together they can ship units with a combined rating of up to 9000 MW annually.

2. Gas-turbine manufacturing

Highlights of Doosan's work as a licensee of GE and Mitsubishi Hitachi Power Systems include the following:

- 1996—two Frame 6Bs for the Hallim combined cycle in Korea.
- 2000—two Frame 6Bs for a project in Thailand.
- 2001—two Frame 6Bs for another Thai project.
- 2008—two M501Fs for the Yeongwol combined cycle.
- 2011—two M501Gs for the Pocheon combined cycle.
- 2012—two M501Fs for the Sejong combined heat and power (CHP) project.
- 2013—three M501Gs for the Hanam & Seoul CHP project.
- 2014—two M501Gs for the Dongtan CHP project.

3. Milestones in DTS's history

- 1996—Advanced Combustion Technology (ACT) opens a 35,000-ft^2 shop dedicated to the repair and rejuvenation of mature-frame nozzles/vanes, blades/buckets, transitions, liners/baskets.
- 2006—Fuel-nozzle flow test and repair facility added.
- 2010—ACT was sold to private-equity firm and renamed ACT Independent Turbo Services.
- 2011—Billy Coleman named CEO and president; certified as a Tier-1 advanced F-class component repair facility; 6-axis rapid-hole EDM, 3-axis sinker/ram EDM, and Schenck moment weigh machine commissioned.
- 2012—Phase 1 rotor shop opened in La Porte. Three Schenck balance machines and a Schenck-ESI static disc balancer installed.
- 2013—Certified to ISO 9001/OHSAS 18001; Phase 2 rotor shop expansion completed and 100-ton crane added; state-of-the-art stacking pit commissioned.
- 2014—Repair/upgrade solution developed for 501F two-piece exhaust system.
- 2015—Phase 3 rotor ship expansion completed; Certified as Tier-1 F-class rotor shop.
- 2016—Consolidated operations at LaPorte.
- 2017—Two coating booths commissioned; Doosan acquired ACT and renamed it Doosan Turbomachinery Services.
- 2018—Discs for 7EA manufactured.

Future plans include a cold-rotor coating facility and final expansion of the rotor building to 420 ft long.

4. La Porte facilities

Doosan's La Porte complex is divided into five active shop areas, with a sixth set aside for expansion when necessary:

- Rotor bay with dual 30-ton cranes.
- Rotor high-bays 1 and 2, each with a 100-ton crane and dual 30-ton hooks.
- Component repair shop, 30- 10- and dual 5-ton cranes.
- Thermal spray coating area with dual 30-ton cranes.

ited the original shop of the founding owner during a user-group meeting in the mid-2000s and the expanded facilities in the same location near Houston's William P Hobby Airport early in this decade after the company was purchased by an investment group.

The new, high-tech La Porte shop, toured by the editors in February 2018, dwarfs its predecessors with more than 100,000 ft^2 of production facilities on an 11-acre site with room to expand (Sidebar 4). ACT had begun transitioning to La Porte under the direction of industry veteran Billy Coleman in 2012 with the opening of what it called its Phase 1 rotor shop.

Particularly important to gas-turbine owner/operators are the rotor and heavy-mechanical capabilities added as part of ACT's expansion in the 2011 to 2017 period before the sale to Doosan, and since. Today, the company has a Tier-1 F-class rating by major power producers and ISO 9001 and OHSAS 18001 certifications.

The La Porte team's accomplishments in rotor repair are a source of great pride at DTS. Forty GE rotors, Frame 3s through 7FAs, have been repaired there already—including five 7FAs in 2017, two with complete unstack/re-stack (Fig 1). One rotor had a long history of problems and was running with up to 6 mils vibration. Repairs reduced that to 1.2 mils, validating staff capabilities.

Doosan's first 501F rotor was at La Porte during CCJ's visit. Replacement of the torque tube and air separator were among the action items. Other noteworthy 501F work involves the exhaust system where issues abound, at least according to presentations and discussion at user-group meetings. Seven two-piece exhaust systems, overhauled and upgraded with Doosan's zero-hour mod, have been returned to service (Fig 2).

The management team (Fig 3) stressed DTS's wide range of repair experience on both new and mature engine technologies and its work in developing innovative engineered solutions to solve chronic issues facing users. The following stops were included in the shop tour:

- Component repair.
- Rotor unstacking/restacking, deblading/re-blading.
- Heavy mechanical—exhaust sections, for example.
- New parts, including 7EA and 7FA rotor discs.
- Cleaning and surface treatment.
- Rotor balancing up to 175,000 lb.
- Thermal spray booth.
- Machining centers with lathes, boring mills (vertical and horizontal), blade tip and surface grinder, etc.
- Electrical discharge machining (EDM) and CNC.
- Welding booth.
- Heat treatment.
- Sonic-nozzle flow testing. CCJ

Rowan

How to detect gas-turbine leaks offline

Challenge. Small leaks are a near certainty in any gasketed system subjected to numerous thermal cycles. Most leaks outside the gas-turbine compartment generally are easy to identify on site walk-downs when the plant is operating. However, entry into the compartment with the gas turbine in service usually is either prohibited or restricted. The challenge facing many O&M technicians: How do you identify GT leaks offline?

Without obvious physical "clues" these leaks can go undetected indefinitely or until they progress further and endanger reliability, heat rate, or unit safety. In the past, several methods have been used to find leaks. "Rag on a stick or pipe" is a classic, as are foil-wrapped flanges; the latter being recommended by various OEMs and fairly effective in practice.

The latest models of hydrocarbon imaging cameras can be useful for identifying natural-gas leaks. But when the gas turbine is operating, excessive compartment turbulence from ventilation fans makes pinpointing a gas leak difficult, if not impossible. Also, these cameras provide no helpful identification of 7FA compressor extraction system leaks common in the ninth- and 13th-stage piping. Given the amount of energy required to drive the compressor these leaks are low hanging fruit for any operating company trying to reach peak unit performance.

Plant Rowan

Owned by Southern Company

Operated by Southern Power

985-MW, gas-fired, 2 × 1 combined cycle plus three units in simple-cycle service, located in Salisbury, NC

Plant manager: Chris Lane

1. Ultrasonic leak detector is effective when the gas turbine is offline and in crank mode

Solution. Plant personnel now conduct system inspections with an ultrasonic leak detector, a UE Ultraprobe® 3000 (Fig 1), with the gas turbine in "crank" mode—at or near 847 rpm for a 7FA. There is ample compressor discharge pressure (CDP), back-fed from gas nozzles and diffusion-air and atomizing-air connections, to verify the integrity of all gas pigtails, flanges, and tubing—even gas-control-valve flanges and packing. Plus, the ninth- and 13th-stage extractions, second- and third-stage nozzle cooling, and piping flanges for the inlet-bleed-heat system as well.

Technicians can use this ultrasonic system with the turbine online (in a pinch), but they cannot recommend it in practice. Specific leaks could not be properly identified because getting close enough to any suspected issue was either impossible or too hazardous. There are several safety issues associated with locating leaks online and the practice is believed an unnecessary risk best avoided–especially considering how easy it is to find leaks offline.

The following are some examples of leaks caught during a recent onsite audit:

- Fig 2 shows a PM1 ring header-to-pigtail flange gasket failure on Can 14. The failure was at the bottom of the flange, facing the turbine. Because of its location, the leak couldn't be seen. The foil wrap was blown out on the bottom but you could not see this from the top.

Also, escaping natural gas was not visible to hydrocarbon imaging because of the amount of air turbu-

2. Technician points to the ring header-to-pigtail flange (left) where the gasket (right) was damaged and allowing leak-by

3. Flange, typical of those in ninth- and 13th-stage extraction lines (left), was broken to replace damaged gasket at right

lence in the compartment. The hazardous gas detectors identified a small leak; however, this slowly decreased as the unit came to operating temperature—a very typical scenario. This leak was located, offline, within 10 minutes using the above "acoustic sweep" protocol.

Fig 3 illustrates a flange leak and gasket condition typically associated with the ninth- and 13th-stage extraction lines. This surely had a negative effect on unit performance. Though the drop in CDP can be difficult to calculate, it remains an easy improvement for unit performance.

Results. The plant has drastically reduced the number of small leaks that typically would have gone undetected. The number of man-hours spent looking for these leaks has been greatly reduced as well. Audits are conducted prior to a water wash, if unit forced cooling is required, or even during the offline water wash process, as appropriate, to avoid the need for additional maintenance outages.

Project participants:

Shaun Lynch, operations technician III
Marcus Kniffin, operations technician II
Mike Sivick, maintenance team leader
Dan Leone, operations team leader

Rathdrum

Rathdrum Power Plant

Owned by Tyr Energy

Operated by NAES Corp

275-MW, gas-fired, 1 × 1 combined cycle located in Rathdrum, Idaho

Plant manager: Gary Allard

Concrete wall facilitates cleanout of cooling-tower basin

Challenge. Rathdrum is permitted as a zero-discharge (ZD) facility. As such, the plant does not discharge any process water offsite. Undesirable solids are removed from the various process-water streams by a mechanical process in the ZD area of the plant. A downside of the ZD system is that the plant is not permitted to discharge the large volume of cooling-tower water during outages, challenging staff in the removal of soda-ash solids that accumulate in the basin.

Clean out of these solids during each annual outage is a best practice because it virtually eliminates plugging of plate-and-frame heat exchangers located throughout the plant. Water must go somewhere to allow basin cleanout. We could move some of it to a 100,000-gal waste tank, but this would fall way short of the tower's 378,000-gal capacity. We would have to rent more than a dozen 21,000-gal Baker tanks at a cost of roughly $5000 per tank to hold the remainder.

Solution. With help from a local engineering firm, staff came up with a plan to clean the basin without renting Baker tanks. It involved building a 54-ft-long wall, equipped with two 2 × 4 ft stainless-steel gates, to divide the basin in two. With the wall in place, plant personnel could pump all the water out of one half, clean that half, and then transfer the water back into the clean end to allow cleaning of the other half (Fig 1).

To prepare for the project, staff conducted a cooling-tower evaporation test to determine how much water could be evaporated from the tower, and how quickly. A few portable Baker tanks were rented to hold any water that could not be evaporated or transferred to other holding areas within the plant. We also had to remove the sound-suppression chevrons from the tower in order to access the basin.

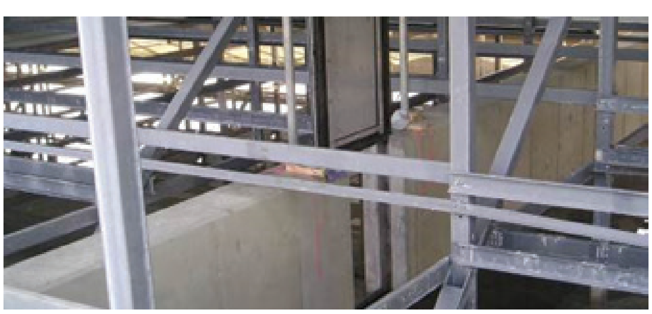
The plant shutdown went well, and we kept the tower basin temperature at approximately 85F to help with evaporation. We transferred as much water as possible to the holding areas to minimize the amount of makeup needed to refill the tower. The five 24-in.-diam riser pipes added a good deal of volume to the basin's 378,000 gallons. Additional water flowed back to the tower basin when we began isolating each of the risers, so the Baker tanks came in handy.

To move the remainder of the water once the main circulating pumps had been shut off, we rented a gasoline-engine-powered trash pump with a 3-ft discharge connection and a capacity of approximately 25,000 gal/hr to expedite the transfer.

After emptying the basin, staff found that the solids measured over a foot deep in some areas. A waste disposal company was hired and its vacuum truck sucked out all the residue and disposed of it. The center of the basin was cleaned out first so the contractor could start installing rebar and building forms for the concrete wall (Fig 2).

Once the wall was completed and the gates installed, staff filled the tower with gates down to test the integrity of the barrier. The gates leaked excessively at first, but held after repairs were made. Next, plant personnel filled the tower to capacity, opened both gates, and started the circ-water pumps to test the flow through the gates. With both circ pumps in service, we achieved a differential level across the wall of between 15 and 20 inches.

After consulting with the engineering firm, plant decided to cut addition-



1. The 54-ft-long concrete divider wall with two stainless-steel gates allows transfer of water from one side to the other, enabling cleanout of the emptied half (above)

2. Disposal company cleaned out the center of the cooling-tower basin first, allowing contractors to start building forms and installing rebar for the concrete wall (right)

3. Since the original installation, plant personnel modified the weir compression panels into knife gates operated by valve wheels

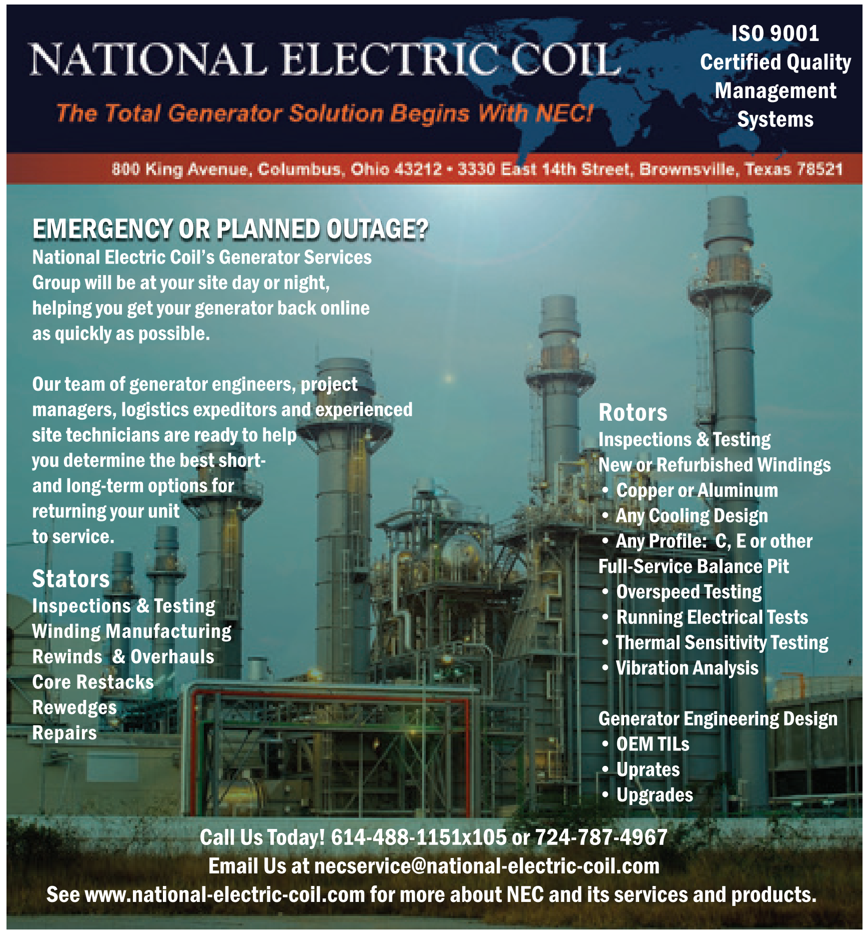
al weir notches in the wall to improve flow characteristics. Once the staff had transferred water to allow them access, the contractors cut two 3-ft-wide overflow weirs 18 in. deep. We coated the cut surfaces with epoxy to protect the exposed rebar and allowed it to cure overnight.

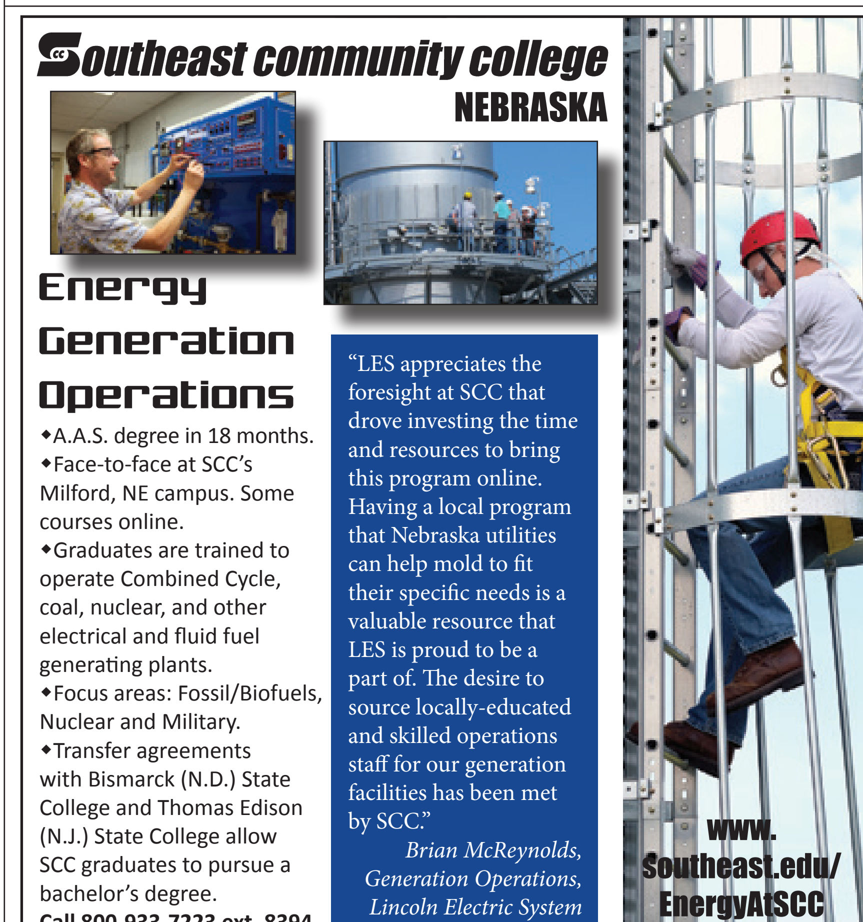
Once again, we filled the tower and placed it into service. The weir notches seemed to allow adequate flow across the wall; the differential level now measured 2 to 3 inches. We installed two-sided gasketed compression panels over the weir opening to prevent water flow between the two basins during cleanouts.

Results. Since the original installation, we've modified the weir compression panels into knife gates operated by valve wheels (Fig 3). These allow the gates to be fully compressed into their channels, further reducing any leakage between the two halves of the basin. We recouped the original cost of building the wall—$15,000—the following year, because we no longer had to rent Baker tanks for storage. Overall, this upgrade has greatly improved our annual planning, staging, and cleaning of the facility's cooling systems.

Project participants:

Tim Mortimer, maintenance supervisor
Mark Villagomez, lead maintenance mechanic
Steve Woolley, EHS supervisor





Nuevo Pemex

Nuevo Pemex Cogeneration

Operated by NAES Corp

277-MW, gas-fired, 2 × 0 cogeneration facility located in Villahermosa, Tabasco, Mexico.

Plant manager: Hugo Ordoñez Ruiz

Leak-testing gas turbines with helium

Challenge. The Nuevo Pemex cogeneration facility in the state of Tabasco, Mexico, is equipped with two 7FA gas turbines, each coupled to a single-pressure HRSG. In cogeneration mode, the plant generates 277 MW and 1.76 million lb/hr of steam.

Maintaining the performance of gas turbines in accordance with OEM specifications, as well as in line with estimated life-cycle degradation, is vital for proper plant operation. Scheduling regular maintenance to identify and repair leaks in the air intake duct prevents compressor fouling, erosion effects, and deposits on the compressor rotor—all of which degrade performance.

Leaks can be traced to defective expansion joints or manhole seals, defective welds, and faulty component assembly. Several household items can be used to test informally for vacuum leaks—including tissue paper, plastic wrap, soap foam, smoke, and shaving cream. However, the following methods deliver more precise, quantifiable results:

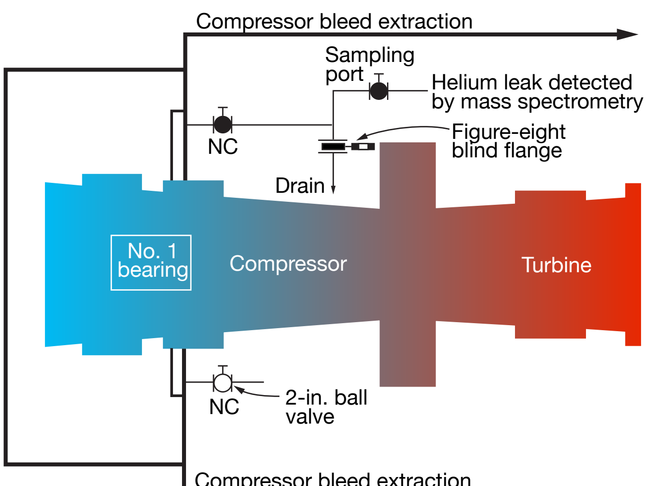
- Ultrasonic measurement (UT).
- Vacuum decay test or pressure rise test.
- Helium sniff.
- Helium spray.

Each of these alternatives has its pros and cons. For example, ultrasonic emits a sound that can be higher or lower, depending on the size and frequency of the leak. Very small leaks emit a high-frequency sound that humans can't hear. This method is not reliable in complex systems where ultrasonic sounds can be produced by multiple leaks as well as other sources. In addition, the leak rate can only be estimated—not measured accurately. Ultrasonic instruments are suitable for finding large leaks but not the small ones typically found in gas turbines.

By contrast, the helium spray method provides a high level of sensitivity as well as quantifiable and reliable results. Helium gas is introduced into the turbine's air intake, where it mixes with ambient air. A mass spectrometer probe is used to detect any helium present at the ninth compression stage. This technology is sensitive enough to detect leaks that traditional methods such as pressure decay and bubble-testing won't find.

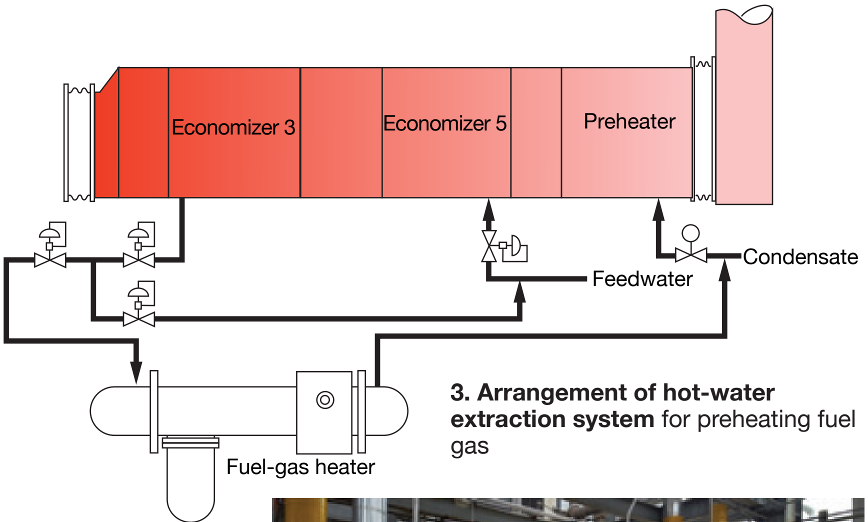
Helium gas makes an excellent tracer. It's non-toxic, inert, non-explosive, and has a particle size so small that it flows freely through any pores or imperfections. Because the ambient atmosphere typically has a helium concentration of only 5 ppm, it allows for greater sensitivity in the test. Before spraying, we measured the amount of helium in the ambient air to establish a baseline. Any value that exceeded this zero point would indicate a leak.

The helium spray method is effective with equipment such as a turbine, which generates a vacuum during operation. The gas in the turbine's air intake duct has a lower differential pressure (relative to the atmosphere). Staff sprayed helium in each of several areas considered susceptible to leaks. If the helium-enriched air entered the axial compressor through a leak, would be detected in the air sample taken from the ninth compression stage.



1. Ninth-stage drain pipe was modified by adding a figure-eight blind flange downstream of the 2-in.-diam shutoff ball valve. Between these two fixtures a sampling port with a ¼-in. ball valve was installed

2. Helium leak test equipment as installed at Nuevo Pemex



3. Arrangement of hot-water extraction system for preheating fuel gas

Since helium is a very light gas, it's important to perform the test on the upper parts of the equipment. It expands rapidly and tends to rise, so if sprayed in a lower area, it can potentially enter a different leakage test point and thus register as a false point of leakage.

4. Water extraction system improved heat rate by 1.6%

Solution. During a planned outage prior to the air leak test, plant personnel modified a ninth-stage compressor water drain pipe by adding a "figure eight" blind flange downstream of the 2-in. shut-off ball valve. Between these two fixtures, they installed a sampling port with a ¼-in. ball valve (Fig 1). During the test, we opened the sampling port, allowing continuous extraction of small amounts of air from the compressor. This enabled us to position the helium probe so that it wouldn't affect turbine operation (Fig 2).

Next step was to determine the time it takes helium to travel from the point of spray to the sampling point. To do this, we sprayed the helium directly upstream of the first-stage filtration system. Travel time for the helium was approximately two seconds, which we used as the reference period.

Sometimes when we injected helium in areas near air prefilters—around an implosion door, for example—and the detection time was greater than two seconds, we concluded that there was a leak. However, the same air flow and turbulences suck air with helium concentration in the environment to the filtration system. When a reading suggested the existence of a leak, we found it was necessary to check the measured value against the reference value—which revealed a detection time of less than two seconds.

Using a Pfeiffer HLT560 mass spectrometry leak detector, we tested the following locations:

- Manhole registers.
- Instrumentation tubing and fittings.
- Expansion joints.
- Implosion door.
- IBH pipe flanges.
- Rainwater drain pipe between the prefilters and fine filters.
- Thermocouples.
- Nozzles for offline washing system.

Results. Staff found no major leaks, but did find small ones in the offline washing nozzles. These were sealed with silicone until permanent repairs would be possible. Note: We weren't able to leak-test the online water wash nozzles because of high operating temperatures. However, based on our findings with the offline nozzles, we sealed the online nozzles as well during a subsequent planned outage. We found a few other small leaks in the differential-pressure transmitter fittings, one in the manhole register, and one in an expansion joint.

Plant achieved the main objective: Optimizing air flow to the compressor. Because the leaks identified and sealed were small both in size and number, technicians were not able to detect a measurable uptick in turbine performance. However, performance improvements in facilities where significant leaks are detected and repaired have been well documented.

Project participants:
Hugo Ordoñez Ruiz, plant manager
Henry Barrios García, plant engineer.

Using HRSG water to heat GT fuel gas

Challenge. Nuevo Pemex initially operated as a simple-cycle facility with an auxiliary boiler to supply hot water to a heat exchanger that preheated fuel gas for the GTs. But after conversion to a cogeneration plant, it made economic sense to use hot water from the HRSGs for preheating the fuel.

Solution. In coordination with Cerrey SA de CV, the HRSG supplier, staff designed and developed a hot-water extraction system. This consisted of a hot-water line connected to the bottom header drain in Economizer 3 to extract water at 404F. A second line to the feed pump discharge was installed to cool the water slightly before it reached the fuel heater inlet. After transferring heat to the fuel gas, water returns to the HRSG at the preheater inlet (Fig 3).

To ensure proper functioning of the gas turbine, GE stipulates requirements for flow, pressure, and temperature of the hot water supplied to the fuel heater. To assure compliance, we added a control valve to maintain water flow at 40,300 lb/hr; a second valve to attemperate the water supplied with cold water to maintain the temperature at 356F; and a third valve to release pressure if it exceeds 550 psig.

Results. The plant's fuel-gas consumption decreased measurably after the water extraction system was installed in January 2016; heat rate improved by 1.6% (Fig 4). By cutting our fuel consumption, we also reduced greenhouse gas emissions. Running in cogeneration mode with the new extraction system, we achieved 100% reliability. (In simple-cycle mode, reliability was adversely impacted by the auxiliary boilers, which had several failure-prone components.)

The auxiliary boilers now are in reserve. The HRSG preheater condensate recirculation pumps are held in reserve as well. This is because the 250F return hot water from the new extraction system is blended with condensate (142F), bringing the temperature to 158F or more, thus preventing the flue-gas temperature from dropping below the dew point and forming condensate.

Project participants:
Ordoñez Ruiz
Henry Barrios García
Guillermo Mondragón García

Faribault

Air attemperation system assures superheated steam on startup

Faribault Energy Park

Owned by Minnesota Municipal Power Agency

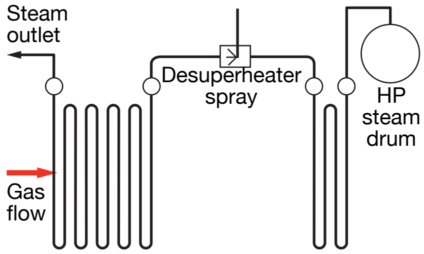
Operated by NAES Corp

300-MW, dual-fuel, 1 x 1 combined cycle located in Faribault, Minn

Plant manager: Bob Burchfield

Challenge. During the early phases of plant startups, gas-turbine (GT) exhaust heats up HP superheater tubes in the heat-recovery steam generator (HRSG) faster than steam can transfer heat away from them. Steam flows generally are too low during startup for effective heat transfer until the steam turbine reaches an appreciable output. Desuperheaters, a/k/a attemperators, sometimes are ineffective during startups because they require a certain amount of steam flow to perform correctly.

Many control room operators address the problem by increasing desuperheater sprays to near-maximum rates during startups, just prior to ramping the gas turbine—this to prevent a GT runback caused by high metal temperature. However, excess sprays often create saturated steam conditions, and this, in combination with thermal cycling, eventually contributes to downstream pipe, tube, and weld failures. Fig 1 illustrates a typical GT exhaust, superheater, and desuperheater spray configuration.



1. Superheater and desuperheater arrangement is typical for an F-class combined cycle

Solution. While studying the impact of faster GT load ramp rates on the HRSG, staff consulted with HRST Inc to analyze thermal stresses and develop solutions to mitigate risk. Distributed control system (DCS) and thermocouple data confirmed that saturated steam conditions could not be mitigated simply by tuning the attemperator valves.

HRST recommended an air attemperation system (AAS)—their QuenchMaster™ model—similar to one being installed at another facility (Fig 2). The AAS operating concept is relatively simple: Ambient air is injected downstream of the gas turbine to cool the hot GT exhaust before it contacts the HRSG piping and tubes. Reducing exhaust temperature by about 50 deg F usually is sufficient to keep tube metal temperatures below recommended limits and reduce the magnitude and frequency of superheater spray-water valve operations.

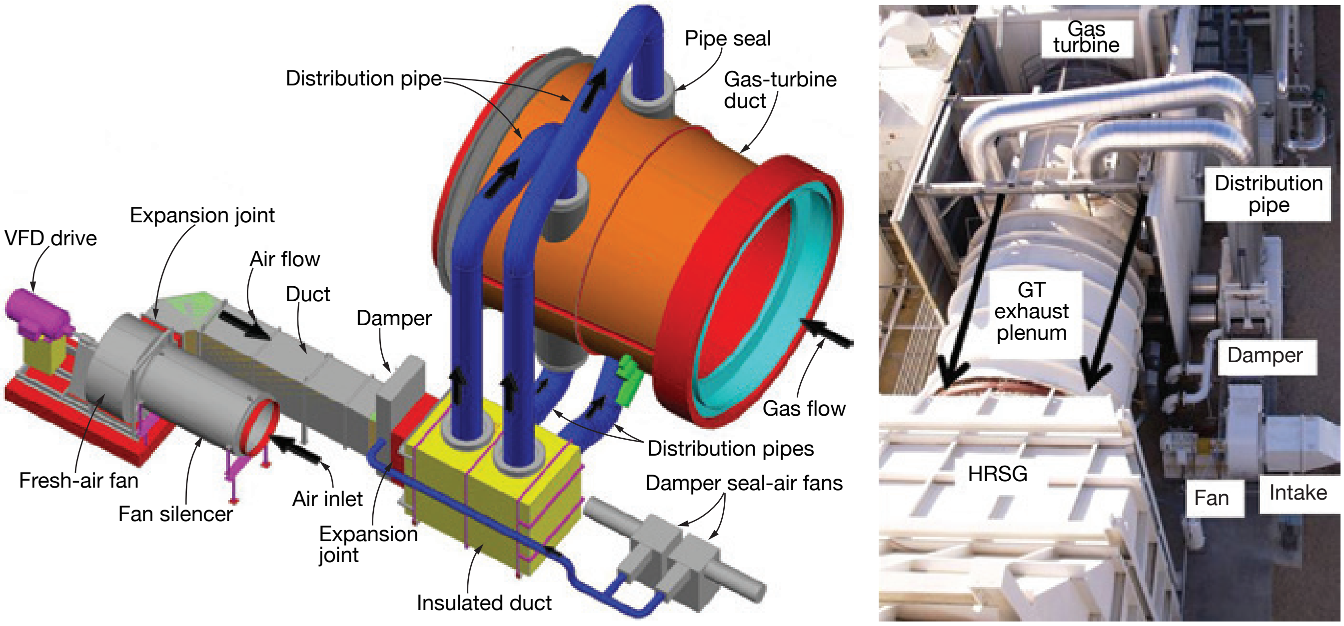
Calculated savings based on reduced plant startup times and HRSG material failure analysis confirmed the value of the QuenchMaster. The project was approved and subsequently completed in 2012.

In addition to the QuenchMaster labor and materials, construction included the following:

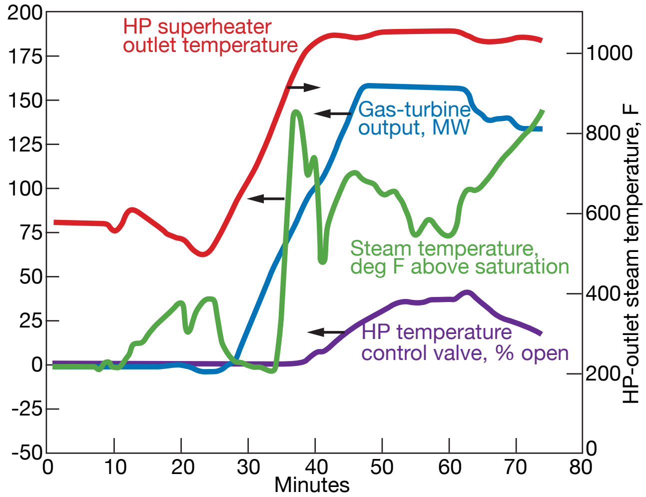
- Soil analysis and new concrete pad.
- Electrical installation to power a 200-hp fan equipped with variable-frequency drive, along with instrumentation and controls.
- Field engineering support for DCS logic changes and graphics.
- A minor air-permit amendment that required little effort thanks to a straightforward operating narrative supplied by HRST.

Results. Prior to installing the air attemperation system, DCS superheat calculations revealed that steam conditions reached saturation dozens of times during each startup (Fig 3). Post-installation testing demonstrated that the QuenchMaster achieved the guaranteed 35 deg F of superheat when in use. Actual results were close to 50 deg F above saturation temperatures with the same starting conditions (Fig 4).

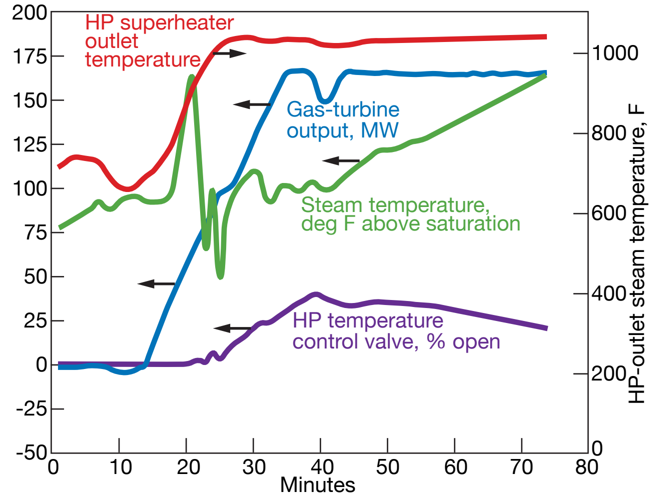
Thermal modeling and damage-fraction analysis indicated that HRSG parts with a normal expected life of 30 years would likely fail after approximately five years under the plant's proposed fast-start profile. The same modeling with the AAS in service restored part lives to near-original expected lifespans.



2. Air attemperation system cools GT exhaust before it contacts the HRSG's HP superheater



3. Hot-start profile before installation of the air attemperation system. Note that HP steam temperature is at, below, or close to saturation for the first 35 minutes of the start

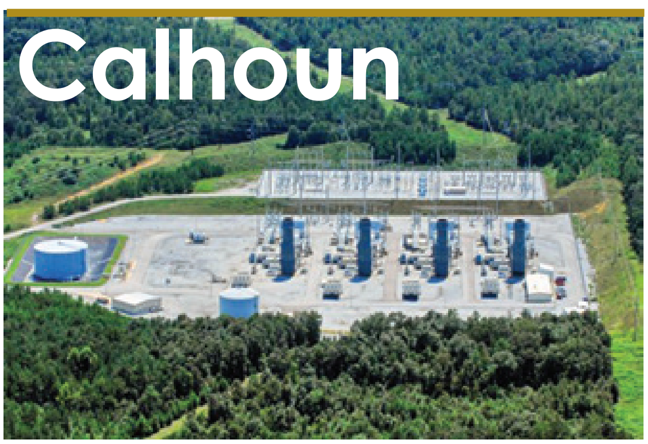


4. With the AAS HP steam temperature is comfortably above saturation during the entire hot start. Also, the GT achieves its desired load about 13 minutes faster than without it

Independent 7F fleet data indicate Faribault's start times are faster than 90% of the facilities operating in similar combined-cycle configurations.

After 4.5 years of operation, we've found no adverse indications during annual X-ray and other NDE inspections of targeted inspection points.

Project participants: Shawn Flake, Bob Burchfield, Ben Garrison, Doug Klar, Bob Flicek, Tim Mallinger.



"T" piping arrangement with go/no-go switching valve allows testing of relief valves without removing CO_2 from the tank

Cardox-tank double relief valves facilitate testing, maintenance

Challenge. Relief valves for the Cardox tank were piped directly into the tank. If there were an issue with either of the relief valves sticking, the tank would have to be emptied prior to doing any work. The tank also had to be emptied to test the relief valves.

Solution. Staff worked with a vendor to make a "T" piping rig with a go/no-go switching valve so relief valves can be tested without removing the CO_2 (photo).

Results. Testing is accomplished by swapping the valve and removing the offline valve. Also, the relief valves have frozen open when tank is venting, and we were able to swap it over to the standby valve to isolate. All of the above prevents either loss of CO_2 or additional budgeting for vendor to remove CO_2 tanks for testing.

Project participant: Mike Carter

Calhoun Power

Owned by East Alabama Generating LLC

Operated by Consolidated Asset Management Services

748-MW, dual-fuel, four-unit simple cycle located in Eastaboga, Ala.

Plant manager: Mike Carter

CEMS backup A/C insert

Challenge. CEMS shacks only have one air-conditioning (A/C) unit. Every other critical A/C-cooled compartment onsite has redundant units. Plant has failed an A/C unit in the CEMS and had no back up to keep critical equipment cool.

Solution. Install an insert into the side of the building capable of holding a "window" A/C unit. Also install an additional receptacle with its own breaker outside of the distribution panel. When not in use, an insulated manway will be in place.

Results. Any A/C failures in the CEMS have not been a problem. The "window" unit can keep the shack cool until repairs can be made.

Project participant: Robin Fletcher

T A Smith

T A Smith Energy Facility

Oglethorpe Power Corp

1250-MW, gas-fired, two 2 × 1 combined cycles located near Dalton, Ga

Plant manager: Rich Wallen (former), Michael D'Avico (current)

Acoustic monitoring provides early leak detection

Challenge. Effectively identify and monitor heat-recovery steam generator (HRSG) tube leaks and attemperator leakage/leak-by. It is difficult for operations personnel to determine remotely when valve leak-by is occurring. EPRI says the failure to adequately atomize attemperator spray flows to high-pressure superheaters (HPSH) and reheaters (RH) is one of the leading causes of premature damage to pressure parts.

Severe thermal-mechanical fatigue damage to the HPSH, RH, headers, and steam piping attributed to quenching by un-atomized condensate exiting the attemperators continues to be a significant industry problem, resulting in avoidable deterioration of unit reliability and significant unnecessary maintenance costs.

Current methods available to plant operators—such as flow-measuring devices and valve-position indication—are not always effective for identifying valve leak-by during no-flow demand conditions. Successfully addressing the quenching problem requires installation of a monitoring system that can alarm the operators of a spray valve or block valve that was "closed," but still leaking through (Fig 1).

1. Acoustic monitor is installed on reheater attemperator spray valve as part of the EPRI-sponsored project at T A Smith

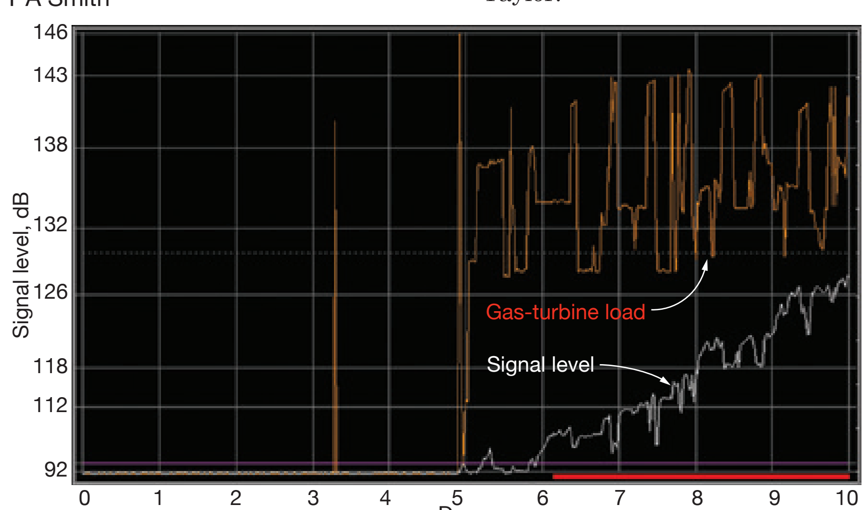
Solution. Plant partnered with Mistras Group in an EPRI-sponsored project and installed the company's AMS acoustic leak-detection monitoring systems on all four HRSGs, as well as on attemperator valves for one unit.

Acoustic monitoring has become an essential part of listening for early tube-leak detection on conventional steam generators and is being adopted now by coal-fired-boiler and HRSG owner/operators. The system is intended for steam leak detection in pressurized vessels—including power boilers, recovery boilers, and feedwater heaters. It performs this function by continuously measuring the internal sounds from the boiler or feedwater heater signaling an alarm when the sound exceeds a preset threshold for a predetermined amount of time.

This technology over the past several years has proven to provide HRSG operators with the first indication of a tube leak, well in advance of all traditional methods. Early leak detection can mitigate the technical and economic consequences of tube leaks. The positive results of acoustic monitoring in HRSGs encouraged staff to consider it for attemperators.

Results. Acoustic monitoring of HRSGs allows owner/operators to manage tube leaks until planned outages by minimizing the number of thermal cycles on the boilers (Fig 2). It also allows staff to better understand potential economic impacts from specific operating profiles. Early indications on attemperators reveal data that allow staff to quickly identify leak-by on valve arrangements.

Project participants: Rich Wallen, Dan Plaisted, Ryan Andrews, Tom Taylor.



2. Acoustic trend line (white) reveals a leak beginning on Day 5. Warning enabled a scheduled shutdown that saved the plant an estimated $80,000 to $100,000

3. T A Smith personnel take time for a photo-op with their Best Practices Award outside one of the two safety shelters installed

Training for this generation and beyond

Challenge. Train personnel adequately and effectively for combined-cycle operations while maintaining focus on budget constraints. Many offsite training offerings are expensive—travel, food, lodging, meals, course fee, etc—and the cost per student can be high.

Solution. Plant partnered with Technical Training Solutions to develop an in-house training program for both Mark VI GT controls and advanced D-11 steam-turbine controls. The total solution incorporated two full weeks of instructor-led onsite training for more than 15 students, plus 365 days of access to upwards of 75 training modules for the staff of 33 employees.

4. Storm shelters each protect more than 30 people against the elements

Results. The highly visual training method implemented leveraged best the different learning styles of today's changing workforce at a cost saving estimated at more than $250,000. Computer-based-training test results indicate a greater retention of learning compared to that for mature methods. This has become a cornerstone of the plant's program for maintaining operational excellence and on-going computer-based training will remain a budget line item.

Project participants: Rich Wallen, Frank Henderson, Joe Duncan.

Tornado safety shelters

Challenge. Safely house station personnel in the event of adverse weather conditions. Tornados and associated wind events are a common occurrence in areas around the plant, especially during the summer.

Solution. Plant purchased two storm shelters from Home Depot to provide safe housing for up to 64 persons (Figs 3 and 4). The shelters meet FEMA 361 and ICC-500 guidelines designed to provide near absolute protection against EF5 tornado winds. They are located at easily accessible locations on the plant site.

Results. Project was executed in less than three months from conceptual design to full implementation—including concrete pours.

Project participants: Barry Johnson, Tim Lieving, Chris Estelle, Ryan Andrews.

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Vandolah Power

Generator isophase-duct-bus purge-air solution

Challenge. Moisture intrusion into the isophase bus duct serving Unit 3 of this four-unit simple-cycle plant caused its PT (potential transformer) and other electrical connections in the breaker enclosure to fail after rain events. Water leaking into the GSU (generator step-up transformer) bushing enclosure would travel down the isophase duct into the generator breaker enclosure (Fig 1).

Solution. Short-term solution was to repair the leaks on the GSU and fix the modification flaw on the A-phase bushing enclosure introduced during plant construction (Fig 2). The same repairs made on Unit 3 were made on all four units at the site.

Long-term solution options were (1) retrofit the bus duct with a positive-pressure system to prevent moisture ingress or (2) install a purge-air system using instrument air to lower the dew point in the bus duct and absorb moisture. The latter, at less than 3% the cost of the former, was selected.

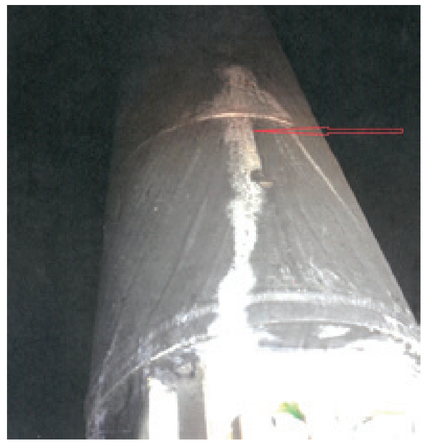
Air from the instrument air system is routed to a purge-air station (Fig 3) which provides air at 2.5 psig to the isophase ducts (Fig 4). Purge air is routed to the secondary side of the plant's four GSUs and the primary side of its two auxiliary transformers (Fig 5).

All work, including fabrication of the regulation station and supply tubing to the isophase ducts, was completed by plant employees.

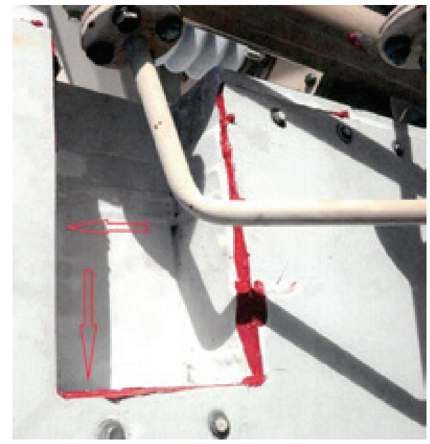
Results. There have been no isophase failures, nor any loss in generation, since the modifications were installed. Benefits of the improvement project also included the following:

- Increase in unit availability.
- Improvement in unit reliability.
- Less maintenance now is required on generator breaker components (man-hours, parts, breaker repairs).
- Service life of the isophase bus and the generator breaker is increased by eliminating moisture ingress; less corrosion.
- Performing work in-house reduced project cost.

Project participants: Michael Singletary, Dale Porter, David Hogue.



1. Unit 3 isophase bus bar (A phase) presents evidence of moisture intrusion



2. Bushing enclosure was modified during plant construction. The flaw introduced has been repaired

3. Purge-air station is equipped with an additional desiccant air dryer, pressure regulator, and pressure gage with isolation valves

Vandolah Power

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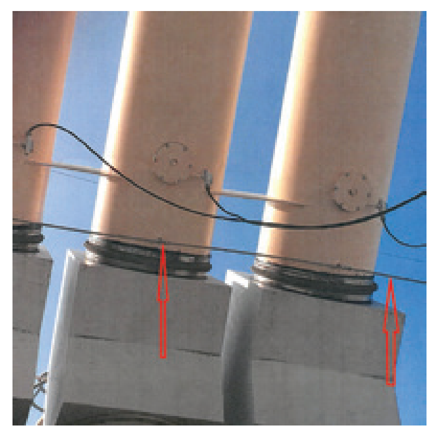
Plant manager: Doug Jensen



4. Tubing delivers purge air to the isophase ducts

5. Purge air is delivered to the primary sides of the two auxiliary transformers

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