

Issue 87 (2026)
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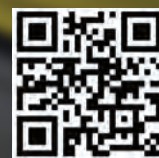
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PLAN AHEAD: UPCOMING INDUSTRY USER GROUPS



Power Users Combined Annual Conferences (CCUG, GUG, PPCUG, STUG, and LCPG) August 24-27

Marriott Rivercenter on the River Walk,
San Antonio, Tex. Details/registration at
www.powerusers.org. Contact: SV Events,
planning.team@sv-events.net.



Combustion Turbine Operations Technical Forum (CTOTF) August 30-September 3

Grand Hyatt River Walk. San Antonio, Tex.
Details/registration at www.ctotf.org. Con-
tact: Christine Doyle, chrisdoyle@ctotf.org.



Wärtsilä Users Group October 12-15

Crowne Plaza French Quarter, New
Orleans, La. Details/registration at
www.powerusers.org. Contact:
Jacki Bennis, jacki@somp.co.



Australasian Boiler and HRSG Forum November 17-19

Brisbane, Australia. Details/registration at
www.abhug.com. Contact: Rachel Wash-
ington, rachel@meccaconcepts.com.au.

2027



501F Users Group February 14-19

The Westin Galleria, Houston, Tex. De-
tails/registration at www.501Fusers.org.
Contact: Jacki Bennis, jacki@somp.co.



501G Users Group February 14-19

The Westin Galleria, Houston, Tex. De-
tails/registration at www.501Gusers.org.

Contact: Jacki Bennis, jacki@somp.co.



FT8 Users Group March 16-18

EPRI Campus, Charlotte, NC. Details/
registration at www.ft8users.com. Contact:
Steering committee, ft8@ft8users.com.



FT4 Users Group March 16-18

EPRI Campus, Charlotte, NC. Details/
registration at www.ft4users.com. Contact:
Steering committee, ft4@ft4users.com.



Western Turbine Users (WTUI) March 21-24

Renaissance Palm Springs Hotel, Palm
Springs, CA. Details/registration at www.wtui.com. Contact: Planning committee,
info@wtui.com.



7F Users Group May 24-28

Grand America Hotel, Salt Lake City, UT.
Details/registration at www.powerusers.org. Contact: SV Events, planning.team@sv-events.net.



European HRSG Forum May 25-27

Monash University, Prato, Italy. Details/
registration at www.europeanhrsgforum.com. Contact: Rachel Washington, rachel@meccaconcepts.com.au.



Legacy Turbine Users Group (Frames 7E, 6B, 5) June 14-17

The Woodlands Waterway Marriott Hotel,
The Woodlands, TX. Details/registration at
www.powerusers.org. Contact: SV Events,
planning.team@sv-events.net.

Editorial Staff

Scott G Schwieger,
Publisher
702-612-9406, scott@ccj-online.com

Crisandel Thornton
Creative Director

Steven C Stultz
Consulting Editor

Clark G Schwieger
Special Projects Manager

Yuri Carreira Alfien
Director, Technology and Innovation

Editorial Advisory Board

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August 24 -27



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Pick your problem: Five Power Users tracks tackle controls, steamers, generators, plant O&M, low-carbon options



The 2026 Power Users Combined Annual Conference returns to the San Antonio Marriott Rivercenter on the River Walk, Aug 24-27. Its working advantage is simple: The Combined Cycle Users Group (CCUG), Power Plant Controls Users Group (PPCUG), Steam Turbine Users Group (STUG), Low Carbon Peer Group (LCPG), and Generator Users Group (GUG) run five parallel programs, and one user registration opens every room.

That matters when your plant problem refuses to respect organization charts. A steam-turbine event can start with a control signal, finish at the generator, and expose a training or spare-parts gap along the way. You do not have to stay in the track represented on your badge. Follow the problem.

The technical sessions are for user attendees. Vendors participate through committee-approved presentations, sponsorships, and the vendor fair. The program summarized here was current July 21, so check the conference site before finalizing your personal agenda.

Each group keeps its own mission and steering committee. CCUG looks at the integrated plant, PPCUG at the control layer, STUG at the steamer, GUG at the generator, and LCPG at dispatchable lower-carbon resources. The separation keeps discussions technical. The shared badge allows attendees to reconnect the pieces. That is useful when a fleet upgrade promises more output at the gas turbine but shifts loads, temperatures, alarms, or inspection requirements elsewhere in the block.

INTEGRATED PLANT: CCUG

Failure mechanisms arrive first. Monday afternoon puts flow-accelerated corrosion in HRSGs ahead of critical-spares management and forced-outage events. The program then moves to evaluation and corrective actions following waterhammer in a cold-reheat line. Those subjects belong together. A damage mechanism is only half the story if the needed material, inspection support, or engineering decision is not available when the unit comes down.

Do not overlook Monday's user roundtable. The short, prepared presentations tell

you what is on the program; the roundtable is where you can ask whether another plant has seen the same symptom and what it checked next.

Supply chain is now an O&M variable. Tuesday's sessions include catalyst-replacement planning in the age of data centers and supply-chain bottlenecks, plus navigating SCR catalyst issues in a long-lead-time market. You might have a sound technical scope and still miss an emissions deadline because the procurement clock started too late. Also on the schedule are operational-knowledge, training, and qualification gaps; valve and seal work; serious-injury and fatality prevention; and varnish mitigation in circulating-oil systems.

Load growth gets a plant-level treatment. Wednesday begins with protecting the shaft-line while managing power demands from AI data centers, followed by aging combined-cycle steam-turbine considerations, AI-assisted decisions, combined-cycle top issues, and outage planning and execution.

The afternoon adds co-optimization of combined-cycle operations with advanced models and AI, hydraulic-system problems, end-of-design-life component requalification, and resilience from Day 1.

Thursday returns to the deck plates with extreme-weather lessons, cloud-based cybersecurity, near-miss and LOTO lessons, confined-space lessons, and balancing corrective and preventive work orders.

CONTROLS: PPCUG

Come early if Mark VIe is new to you. Monday morning offers both beginner and experienced plant-control training. The afternoon advances from digital process control and predictive analytics to generator protection and controls TIL implementation. This is a useful sequence for a controls engineer, but it also gives operators and maintenance personnel a common vocabulary before the more detailed case histories begin.

A control system has a lifecycle, too. Tuesday covers data centers from a controls perspective, heavy-duty turbine control using MBC and OpFlex, steam-turbine control capabilities, plant-control lifecycle management, fleet controls issues, smart-signal and

asset-performance management, remote support, and the control system of the future. Wednesday follows with machine-learning anomaly detection, the evolution of NERC MOD-027-1 into MOD-026-2, DCS optimization after gas-turbine upgrades, an alternative to OEM model-based-control black-box logic for the 7FA, and remote monitoring intended to prevent trips and preserve output.

The balance-of-plant assessment following turbine upgrades deserves attention outside the controls department. A new gas-turbine operating envelope can make an old permissive, valve sequence, or alarm philosophy the next constraint. The control change that looks small on a screen can be expensive in the field.

Thursday includes a CPS Energy session on why quizzes can build better plant operators than lectures, plus a Salt River Project and Lone Star Controls case history on a controls retrofit to Mark VIe. If your upgrade plan stops at hardware cutover, both sessions are reminders that the people operating the new system are part of the scope.

STEAM TURBINE: STUG

Start at the turbine deck. STUG opens with EPRI's state-of-the-industry report, ST101, key steam-turbine issues, and EPRI resources. Monday afternoon's field findings from Viking Turbine Services then puts observed turbine-deck problems in front of the room. This is the right place to compare what you are seeing with what others have already found.

Life-extension decisions dominate Tuesday. Siemens Energy's fleet insights lead into end-of-design-life component requalification, modernization applications on combined-cycle plants, and varnish in circulating-oil systems. The program then drills into casing cracking, rotor-life assessment, blading damage and repair, section replacement and uprate planning, operation under abnormal conditions, combined-cycle valve and seal work, and actuator refurbishment and controls considerations.

Use the data you already collect. Wednesday includes GE Vernova top issues and TILs, the half-joint stud and nut update associated with GEK122083, and a presenta-

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tion on using operating data to quantify major-outage improvements. Valve challenges, ASP and NGV experience, the sourcing and repair-shop network, legacy Alstom outage considerations, rotor bow, key documents for the O&M manual, and aging-unit considerations fill out the day. Bring your own problem list. How often do you find only one aging issue?

Before the meeting, compare your bulletin list, last major-outage findings, and open engineering recommendations with these titles. The value is not simply hearing the fleet update. It is leaving with a shorter list of uncertainties for your next scope.

GENERATOR: GUG

Diagnostics should come before the rewind decision. Monday moves from continuous asset-health analytics to offline diagnostic testing and visual inspections, rotor turn-to-turn testing, magnetization screening, generator purge packages, and stator-core testing and repair. Tuesday adds generator field failures, an LM6000 partial rewind, maintenance-program development, stator-core challenges, high-voltage bushings, end-winding block modifications, stator-bar insulation cracking, and generator cooling.

Plan the fleet, not only the next outage. The agenda pairs asset-management-program development with condition monitoring, vibration and winding integrity, root-cause and TIL reviews, H65 design enhancements, rotating-excitation maintenance, collector-ring care, maintenance-outage testing for inner-cooled units, fleet major findings, and proactive GVPI replacement plans. That is enough material to test whether in-

spection scopes and contingency plans are aligned across machines.

Look for the decision points behind each inspection: what result changes the outage scope, what can remain in service, and what evidence justifies a rewind or replacement. A test without an agreed response threshold is only data.

Thursday is the case-history morning: vibration sparking and spark erosion, an Aeropac 1 ground-fault investigation and recovery, a stator rewind driven by high EL-CID readings, stator ground-fault analysis, and a Westinghouse modular-unit rewind. These are the sessions to attend with your test records and one-line diagrams close at hand.

LOW-CARBON FIRM RESOURCES: LCPG

The subgroup format is the point. LCPG was organized so utilities can evaluate low-carbon firm, dispatchable resources together rather than make every company learn through its own pilot. Monday begins with technology priorities, conference goals, current challenges, and commercialization of emerging technologies. Tuesday moves through hyperscaler demand, IRP and supply-chain issues, fuel cells, linear generators, long-duration energy storage, Echogen power systems, nuclear updates, and fusion.

No single technology gets the whole day. Wednesday's roundtable asks how members can get more value from LCPG, then the track covers geothermal, cleaning up combined cycles, carbon-capture economics, hydrogen and clean fuels, and integrated methane pyrolysis. An optional Southwest

Research tour follows Thursday. If your resource plan must remain dispatchable while carbon intensity falls, this room offers a fast comparison of options that otherwise live in separate conferences.

This is also the track for the questions that do not fit a vendor slide: siting, fuel supply, integration with existing assets, operating duty, and what a demonstration actually proved. A peer group earns its keep when an incomplete answer stays incomplete until the evidence catches up.

WORK THE FIVE-ROOM FORMAT

Map conflicts before you arrive. The agenda contains deliberate crossovers: AI and data-center demand appear in CCUG, PPCUG, and LCPG; life extension runs through CCUG, STUG, and GUG; outage execution touches nearly everything. If your company is sending more than one person, divide the rooms and compare notes before dinner.

Use the vendor-fair windows. Vendor fairs with lunch and evening networking are scheduled Tuesday and Wednesday. Technical presentations are supposed to stay technical; selling belongs on the exhibit floor. That separation gives you a place to challenge the mechanism in the meeting room, then ask about parts, tooling, schedule, and support at the booth.

The conference adjourns at noon Thursday, followed by a limited-space tour of MD&A's San Antonio Service Center from 1 to 4 p.m. Watch the Power Users archives for slide decks authorized for release; access is limited to registered owner/operators. If you do not already have a library card, register before you get home. [CCJ](#)

STEERING COMMITTEE DIRECTORY

Combined Cycle Users Group (CCUG)

Mission focus: Integrated combined-cycle, CHP, and cogeneration plant design, construction, operation, maintenance, safety, regulatory issues, and workforce development.

Olivia Ambuehl, Dominion Energy
Phyllis Gassert, Talen Energy
Jason Jauregui, CAMS
Aaron Kitzmiller, Vistra Corp
Robert Mash, GE Vernova O&M Services
Jonathan Miller, Calpine
Jon Mongold, NAES Corp
Brady Parscale, NAES Corp
Marih Salvat, Tenaska

Generator Users Group (GUG)

Mission focus: Owner/operator exchange on generator design, installation, operation, maintenance, overhaul, safety, reliability, efficiency, and transfer of experience.

Ryan Copley, PE, TECO/Tampa Electric
Leopoldo Duque Balderas, Valia Energía
Andres Olivares, Calpine Corp
Jeff Phelps, Southern Company

Joe Riebau, Constellation Power
Jagadeesh Srirama, NV Energy
Mike Young, Salt River Project

Low Carbon Peer Group (LCPG)

Mission focus: Collaborative evaluation, deployment, and information sharing for low-carbon firm, dispatchable resources across technologies and regions.

Ben Carmichael, Southern Company
Dan Connors, American Electric Power
Alan Ettlinger, New York Power Authority
Todd Flowers, Dominion Energy
Lucy Metzroth, Xcel Energy
Adam Reichenbach, Duke Energy

Power Plant Controls Users Group (PPCUG)

Mission focus: OEM- and technology-agnostic exchange on controls hardware, software, instrumentation, cybersecurity, digital transformation, and plant-control-system performance.

Richard Chiafalo, Dominion Energy
Brian Hall, TECO
Zamantha Lopez Aldaco, Salt River Project

David Martorana, Tenaska
Eric Mui, CPS Energy
Peter So, Clearway Energy Group

Steam Turbine Users Group (STUG)

Mission focus: Open owner/operator exchange on combined-cycle steam-turbine and associated generator operation, maintenance, inspection, troubleshooting, repair, performance, and reliability.

Jake English, Duke Energy
Jared Harrell, OxyChem
Jay Hoffman, Tenaska
Connor Hurst, TECO
Celeste Menard, NextEra Energy/Florida Power & Light (FPL)
John McQuerry, Calpine Corp
Jeremy Pou, Tennessee Valley Authority (TVA)
Matt Radcliff, Dominion Energy
Brandon Stewart, Southern Company
Seth Story, Vistra Corp
Steven Weaver, Salt River Project

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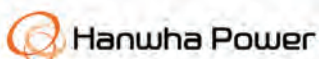
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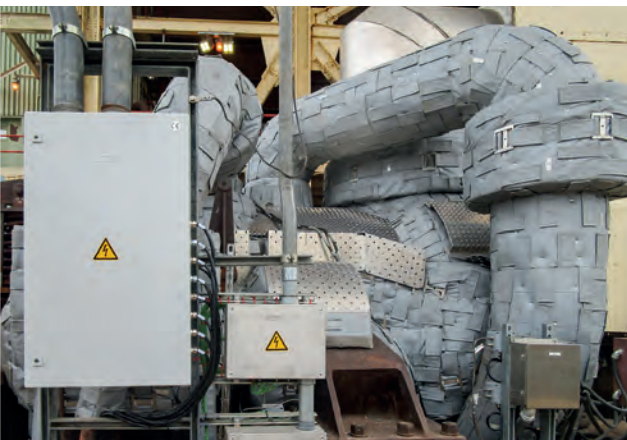
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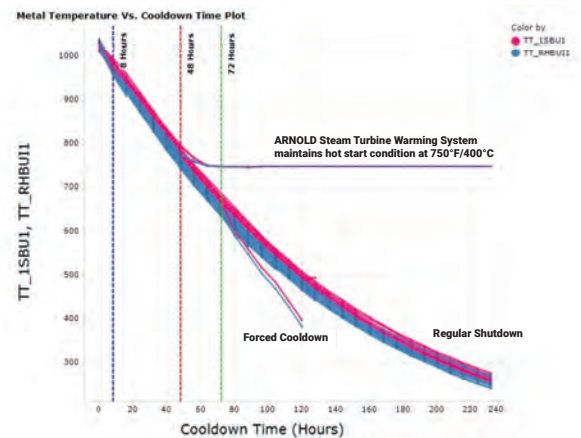
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And other things that can keep a plant manager up at night

By Joseph Harmes, consulting editor

The U.S. is undergoing a transformational shift in how energy is used and generated as demand rises at its fastest rate in 20 years, spurred by electric vehicles and a proliferation of energy hungry data centers. The nation's 12,500 utility-scale power plants, meanwhile, struggle just to satisfy mounting residential consumption while the U.S. Department of Energy estimates data centers will absorb 12-percent of the nation's electricity by 2028.

Concurrently, the energy industry isn't in great shape. The recently released Infrastructure Report Card 2025 compiled by the American Society of Civil Engineers (ASCE) graded it a D+, a decline from C- in 2021. The obstacles to boosting the ranking are formidable: Growth is constrained by aging assets needing to be replaced or modernized while the work force shrinks and experienced employees retire.

And those, says Tim Jackson, power plant manager at the Treasure Coast Energy Center (TCEC) in Ft. Pierce, FL, are among "some of the things that keep me up at night."

The 69-acre TCEC is owned by Florida Municipal Power Agency (FMPA), a wholesale power supplier for 13 municipal electric utilities (FMPA owns six power plants) located primarily on the state's Atlantic sea-

board, from Jacksonville Beach to Key West.

"FMPA was created so its owner-customers could jointly own generation, buy low-cost fuel and manage power supply more economically and reliably than each could alone," says Jackson, who has worked at FMPA for 19 years. "At FMPA, reliability, economics, efficiency and availability are the key aspects to what makes this a fantastic deal for our member-owner customers, that they get to have the benefit of this low-cost power."

GENERATING POWER—AND IDEAS

The TCEC unit is often called an economical and reliable "workhorse" in FMPA's generation fleet. The 300-megawatt natural gas-fired plant went commercial in 2008 and annually operates for over 8,000 hours and produces about two million MWh with two hydrogen-cooled generators, each with about 142,000 operating hours (at the time of this study).

"It's called a one-on-one combined cycle plant, and it makes approximately 160 megawatts from the gas turbine, and then the rest from the steam turbine, and we get that extra power to the steam turbine utilizing a duct burner that's inside the HRSG (heat recovery steam generator) which greatly

improves the usefulness of it and the output," Jackson says. "This results in higher steam flow, increased steam turbine output, increased total plant megawatts. By adding the HRSG steam turbine combination we take that efficiency from 10,500 BTU down to about a 7,000 BTU per kilowatt rate."

And in today's landscape, every kWh and MWh count. A tsunami of demand might soon engulf St. Lucie County. Although developers hit pause at the end of February pending new legislation in the state capitol, plans remain active for Project Jarvis, officially known as the Sentinel Grove Technology Park, not far from TCEC. The \$13.5 billion hyperscale data center will be one of the largest in the world. It's designed to consume one gigawatt of power, capable of supplying electricity for up to one million households, or 2.5 million people, notable as the entire Treasure Coast region has a population of just over 721,000.

Jackson leans heavily on his staff of 16 people who operate and maintain the plant, buttressed by FMPA engineers. "Some of the things that keep me up at night are how am I affecting people? People are probably my biggest concern, but it's also how I get things done. I'm not the expert of everything. I rely totally on my people to do what I need to have done."

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DEFINING-AND REFINING—THE PROJECT

“As part of what we’re doing here, we were looking at ways to make this plant more efficient, more reliable,” Jackson explains on a “hard hat” walkdown of recent TCEC equipment retrofits and upgrades. “Some of the equipment is to that age where it needs to be replaced, upgraded. One of the things that we looked at was to install a process to purge the steam turbine generator remotely, since it can’t be remotely degassed from H2 to CO2.”

“As we were looking at that process and the equipment involved, one of the operators was like, ‘Hey, why are we just doing the steam turbine? The gas turbine is so much harder, and it’s nowhere near as safe to degas as the steam. The steam turbine is much easier. It’s just not remotely operated,’” Jackson says.

“I was the first one to receive the call saying they needed help with a Dual Hydrogen Control Panel (DHCP),” says Rafael Lemus, an account representative for Classic Controls which represents roughly 40 different companies. “I told him that we could get the upgrades he needed and get the unit back up to spec, but that it was better off upgrading the unit and other systems as well.”

Lemus, in turn, contacted Environment One Corporation’s (E/One) Utility Systems Business in Niskayuna, NY, an internationally recognized pioneer in the sector which designed the first field prototypes of its Generator Condition Monitor for General Electric in the early 1970s and introduced generator gas purity monitoring for hydrogen-cooled generators and overheat monitoring for air-cooled generators.

“This was a combination of upgraded equipment and retrofitting of automation equipment and software,” says Mark Williams, business development manager for E/One’s Utility Systems Business (USB). “The part that I like most is putting all the pieces together. Evaluating what the customer has, what the customer’s needs are, and how we can best put together a solution that’s going to make their plant more efficient and safer.”

The project became a turnkey mechanical and electrical installation with E/One site supervision, startup and training. The checklist included:

- A 7F automated purge kit (the components needed to modify the 7F manifold for automated purge processes).
- DHCP Enhanced Purge Software/Electronics Package (providing the ability to remotely change and monitor the gas being used during the purge process displayed on the DCS purge screen. Uses circuit boards and embedded enhanced purge software only available from E/One).
- Ambient vaporizers (a critical part of the system to meet the faster purge times from H2 to CO2 in 60-90 minutes).

- An operator-initiated automated purge system (for emergency and maintenance processes).
- Remote Actuators (enable the generator automated-degas system) and remote actuator panel (used on existing manifolds that are in good condition with H2 rated manual valves).
- Remote Operator Initiated Purge Panels (Using analog and digital signals combined with Mark VIe software programming with Purge screens remotely operate and monitor the purge process from the control room.)
- Two Generator Gas Dryers II (a dual-chamber system that continuously dries and recirculates generator cooling gas—even when the generator is on turning gear, which is a critical time to maintain low dew point).
- Generator Gas Manifold modifications (for an automated purge process).

PURGING GENERATORS—AND HOURS

Purging a hydrogen generator generally takes six-to-twelve hours or longer to safely remove hydrogen gas from a generator case and replace it with an inert gas (CO2) to prevent explosive mixtures of hydrogen in air from forming. When a generator is shut down, hydrogen is purged with CO2 which is then purged with air. During re-gassing, air is purged out with CO2 which is then purged out with hydrogen.

Hydrogen is 14 times more efficient than air in removing heat and greatly reduces windage friction losses. Colorless, odorless, tasteless and nontoxic, hydrogen exists as a gas at atmospheric temperatures and pressure but is flammable or explosive between 5% -75% H2 in Air. It burns with a pale blue, almost invisible flame when concentrations of air exceed safe limits.

“Part of the equipment that’s involved in

what we added or what’s already there is, there are hydrogen storage tubes which we already had that are piped directly into the generator,” Jackson says. “And we had CO2 bottles that were remote as well but completely inefficient because you can’t flow a lot of CO2 because then it ices up.” When dry ice is formed, 30-percent or more CO2 is lost in each bottle.

“What we have now is the E/One system with the liquid CO2 bottles and they’re in their own separate rack which we can just pick up and move and replace anytime that we need to. We can use up all the bottles, remove them, bring in another rack and have it all set up,” Jackson says.

“So, you have the CO2 bottles, some regulators (feeding) into what is called the vaporizer. This thing is a magic piece of equipment that is just a beautiful piece of aluminum. It’s almost like artwork (and) performs this function of taking this liquid CO2 and turning it into a gas without freezing up,” Jackson says. “And it performs this flawlessly. You can see where it starts to frost up and then dissipates across the different stages.

“From there it has some valving and some controls of the flow and you’re measuring the flow as you purge this generator with the CO2,” Jackson says. “The vaporizer we’ve installed is ambient operated, which means we don’t have to have a heater or any kind of electrical power to supply the vaporizer in this E/One platform.”

SPOOLING AROUND

The piping was reorganized so that the spool piece, formerly under the collector house inside an access door at the back of the manifold, was relocated to the outside piping on the H2 gas feed line for easy access for removal. “A safety spool is an integral feature to ensure that dangerous mixtures of H2 and air are avoided,” says Williams.



1. Treasure Coast Energy Center plant manager, Tim Jackson, describes their remote generator-purge upgrade that improved safety, simplified operations, and cut purge time from six to eight hours down to about one. Part 1 shows why this project mattered for reliability, flexibility, and operator protection. Scan QR



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"This is really where the safety of this comes in," Jackson says. "(Now) the spool piece is not hidden up in this cabinet that you can hardly get your fingers into to remove it or to replace it. Now, we can remove the spool piece easily, and we know that there's no hydrogen gas inside the generator."

RETIRING THE OLD DRYERS

Apart from the introduction of the automated purge process, the retrofit of the dryers was "central to our operations," Jackson says. "The two existing dryers were in place for a long time with poor functionality."

Among their issues: age, the outlet dew points higher than the inlet dew point, the requirement of chilled water and house air, float trap issues, and no verification of H₂ outlet dew point monitoring confirming drying of the gas.

The GGD II monitors provide inlet/outlet dew points for optimal performance, a positive displacement blower to ensure drying across all phases of generation operation, the elimination of house air and chilled water connections, increased generator efficiency and reduced downtime, a self-monitored drying process with annual preventive maintenance as opposed to quarterly. The GGD has a 20-25-year lifecycle with many installed in the early 2000s still in service.

"Our prior system was water-cooled with auxiliary cooling water. This system does not have that," Jackson says. "Cooling water to us is like gold. You do not utilize cooling water, that cooling water is used in a different area where you're going to improve the efficiency. That alone improved our efficiency. And then, of course, they're a nice color. So that helps out too."

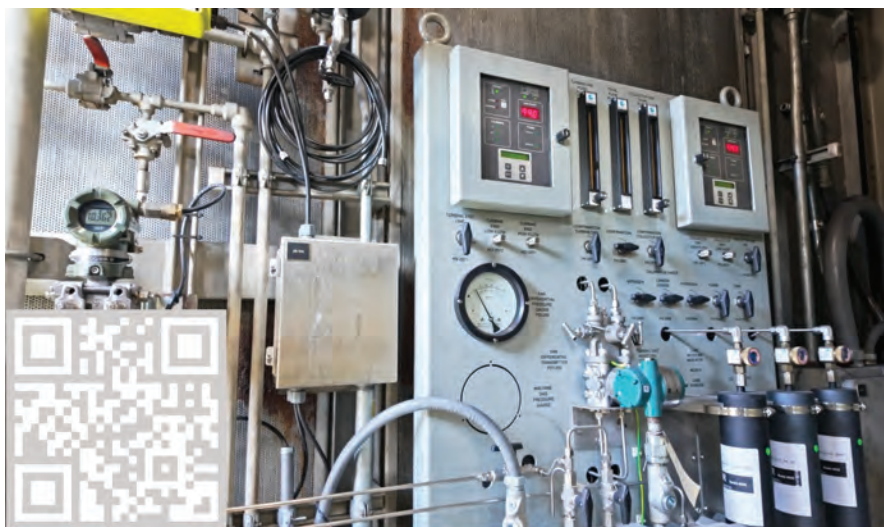
RUST NEVER SLEEPS

The GGD also is designed for hazardous location operation. TCEC's equipment is situated in an open-air environment just seven miles from the stretch of the Atlantic known as the Treasure Coast, whose name refers to the Spanish treasure fleet that was lost in a 1715 hurricane.

"We're close to an ocean," says Jackson. "Our previous dryer was very old and very rusty. It was kind of decaying and needed to be replaced," says Jackson. "Salt air—especially in coastal regions—will affect the power plant equipment due to its high chloride content and the high moisture content of the air to transport it. These two factors accelerate corrosion and material degradation. The materials selected must be able to endure this environment," he adds.

HURRICANE PREPAREDNESS

"The hurricane season lasts for many, many months, and if we can operate for a longer period of time before we're required to shut down, it would help us out. Our goal is to minimize or eliminate downtime whenever



2. See how TCEC modernized a critical generator support system with a new dryer and fast purge upgrade that reduced cooling-water dependence, streamlined operations, and strengthened outage and storm-readiness. In Part 2, plant and vendor teams walk through the decision process, installation, controls integration, and post-startup support that made the project a success. Scan QR

it is safe to do so," Jackson says.

"Shutdown decisions are based on forecasted wind speeds at the plant. Site improvements have increased the unit's wind speed operating tolerance, allowing us to remain online through recent hurricanes. If forecasted winds exceed safe operating limits, we can remotely degas the generators from the control room, which allows the unit to operate longer before shutdown."

Remote Operator Initiated Purge becomes invaluable for employee safety during hurricanes because "if remote degassing were not available, the unit would need to be taken offline before sustained winds reach approximately 40 mph to allow personnel to safely perform the procedure locally," Jackson says.

"The thing that's going to increase the reliability of the plant is letting the operators be able to control when that happens—and remotely from inside this control room," Jackson says. "It gives us a bigger window to operate in and protects them from having to go out into the elements to perform this evolution."

"Now, from the control room on the Mark VIe, we are able to select the purge platform that we choose," Jackson says. "We can either do it in a fast purge for safety or a Maintenance purge (hydrogen-to-CO₂, CO₂-to-hydrogen). "Prior to having this E/One system we had to go out there and what used to take six to eight hours is now accomplished in one."

"The operators love this. They're not standing out there on the concrete in the field to perform this function," says Jackson. "It saves a vast amount of time which increases our reliability and the amount of time that we can operate because we're not gonna have to schedule in that eight-hour

purge time before we can actually work on a generator."

SUCCESSFUL PROJECTS CAN CURE INSOMNIA

The plant's new equipment was refined after a few glitches were addressed.

"Since we've installed our system, we've had a couple of minor, minor issues with our E/One

system that required a phone call," Jackson says. "One of the things was, we couldn't get this regulator to regulate. We had way too much flow, we had too little flow, and we couldn't understand why we had no control. And gave E/One a call."

"They sent down a new regulator within two days and came right to the site and (E/One representatives) took a look at what we were doing and said, 'Look, we just need to change out the regulator' and it's perfect."

Another issue involved valves which "had been labeled backwards. Once they were correctly identified and connected, it worked perfectly."

"With regards to E/One equipment, I really see it as a value add for the customer," says Lemus. "It improves their reliability and it improves their maintenance cycles on a very critical part of the plant, which is the hydrogen monitoring system for the generators."

As for future plans, Williams says he's "excited to demonstrate the newly installed equipment to sister plants. Capturing every bit of power is the goal."

And even though Jackson may have some sleepless nights, he has no regrets. "This is a fantastic place to work. I love being in a power plant. I've had time where I was in an office and time in a power plant, and days in a power plant are fantastic days." **CCJ**



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— SHANE R., CLIENT

Collaboration may not be a choice as screws tighten on CC plants



Future electricity demand growth accelerates. Supply chain constraints intensify. Carbon emissions rules ease. Existing combined cycle (CC) major equipment from the last boom (1997-2003) closes in on original end-of-life dates. Construction of hyper-scale data centers, with their seemingly insatiable electricity needs, takes on a life of its own while AI (artificial intelligence) takes up permanent residence in the public's consciousness.

Gas-fired power plants are back! Natural gas, a "bridge" fuel (to the renewable era) a few short years ago, is now being characterized as a "foundation" fuel. Even coal units, once slated for retirement, are being pressed back into service. There's even talk of a new wave of nuclear power units.

For the powerplant community, whether the AI boom, with its powerplant "supercycle" build out, materializes is less important than the fact that everyone *thinks* it's going to happen. That puts enormous pressure on the supply chain for at least the next several years.

Collaboration and creativity will both be essential, and one of the best places for both is the Power Users Combined Conference, comprising the Combined Cycle Users Group (CCUG), Generator Users Group (GUG), Steam Turbine Users Group (STUG), Power Plant Controls Users Group (PPCUG), and the Low Carbon Peer Group (LCPG).

As you'll read in this report from the 2025 mega-event in Washington DC (most supporting slide decks available to end users registered at www.powerusers.org), bread and butter sessions and roundtables on user-driven O&M experiences, failure causes and recovery, and vendor solutions and new technologies, help the entire community learn and do better.

Keep in mind that *in-person attendance* is more critical than ever as liability risks from disclosures make everyone wary of an indelible record lurking in a storage bank somewhere ready to be mis-interpreted. And in keeping with recent practice, the GE and Siemens slide decks are not available at the Power Users site. As lead times for critical

components enter the realm of the absurd, and even "stock" items get difficult to procure, your "supplier" may be the friend you just made at a user conference.

Several of the industry level presentations, repeated for each user group, along with a few presentations which apply across the board, are summarized first, before diving into the parallel conference sessions.

CYBER THREAT LANDSCAPE

In "Physical and Cyber Security of Power Plant Locations in the United States," after reviewing the "threat environment," representatives from the Federal Cybersecurity and Infrastructure Security Agency advised attendees to make sure to test backup digital systems quarterly or at the very least annually. Common vulnerabilities in power plant systems include outdated software, lack of encryption, insufficient access controls, and lack of IT/OT segmentation, adding that OT systems use specialized protocols that are often "insecure by default."

Slide 14 will be of particular interest as it lists a plethora of voluntary and no-cost cybersecurity offerings from the agency.

THE THIRD ENERGY BUBBLE

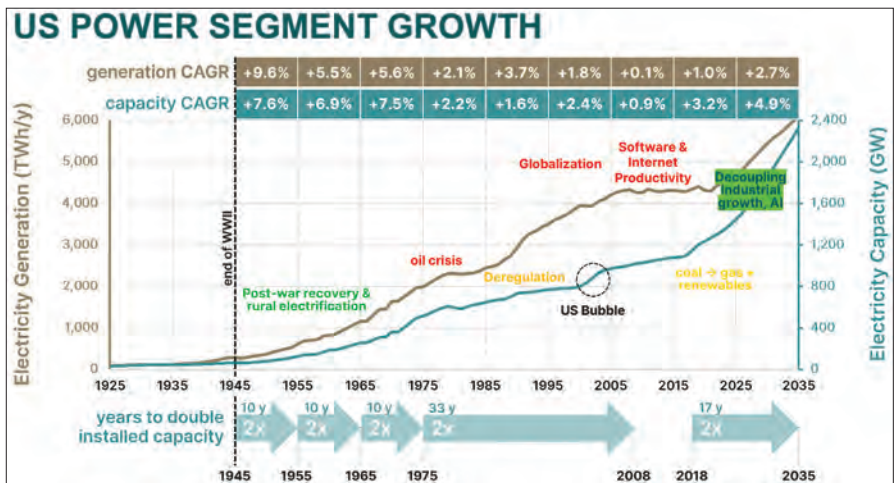
In a presentation titled "Energy's Great

Awakening," two industry veterans called the coming landscape for gas turbines (2025-2040) the "third energy bubble," the first being 1965-1975 when utilities purchased hundreds of GTs for peaking plants, and the second being 1995-2005 after natural gas was fully deregulated and the power industry ordered and installed several hundred thousand megawatts of gas-fired GT capacity. The presenters claim that this supercycle (Fig 1) will resemble the post-WWII build out of the U.S. power grid more than the second US bubble.

New build, existing asset refurbishment and replacement, and demand from heavy industry are "three streams converging to squeeze the supply chain"– the same raw materials suppliers, the same casting and forging houses, and the same install and craft expertise – with a "tropical storm named data center stalled over the top." As one example of the trajectory, global GT orders in 2025 doubled over the 2023 level. Fans of the Ford F-150 truck will enjoy slide 12: What type of truck owner are you?

LUSTER OF NATURAL GAS RESTORED

"Gas is a foundational fuel," argues the presenter of "The Future of the Combined Cy-



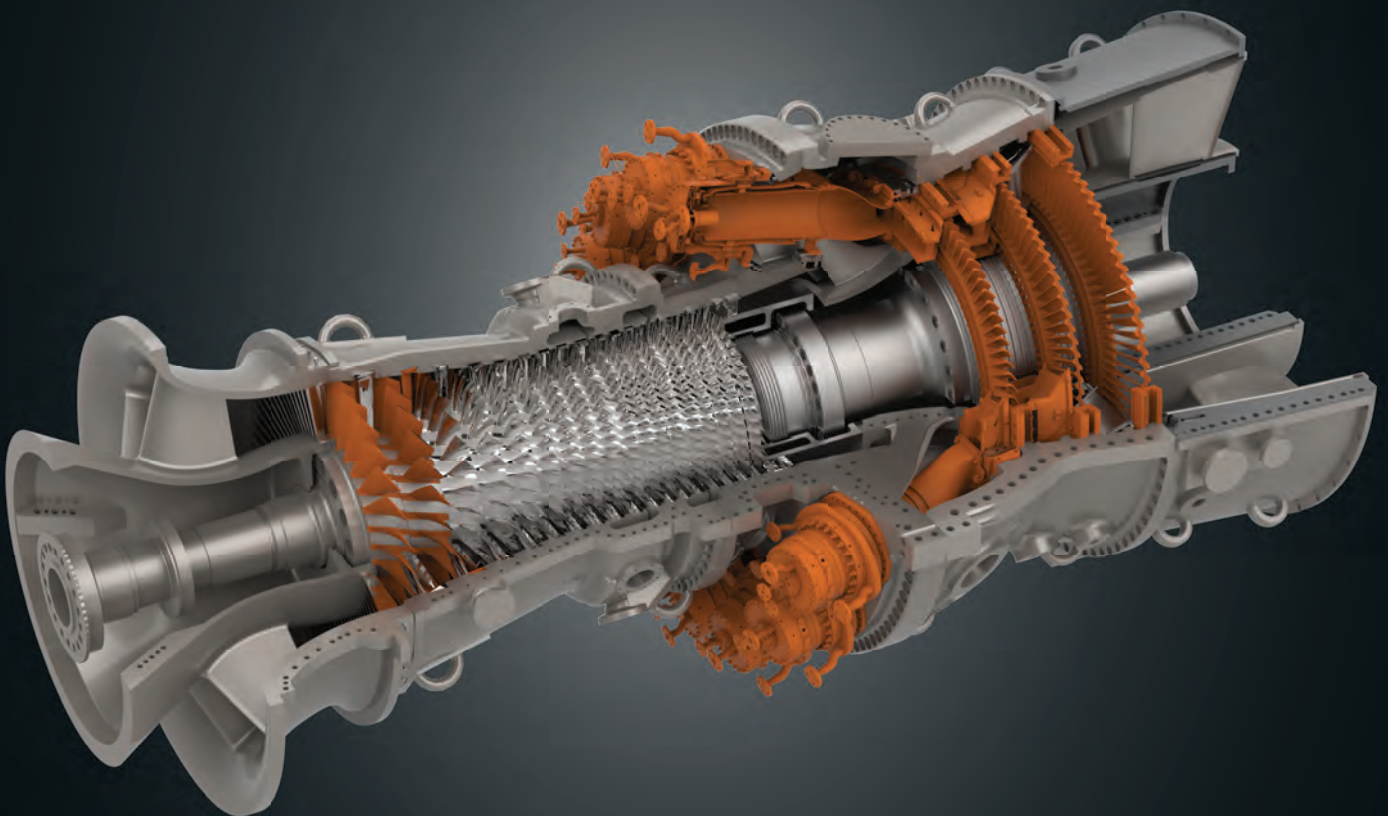
1. What's forecasted for electric capacity additions dwarfs the relatively short US GT orders "bubble" period, according to major OEM

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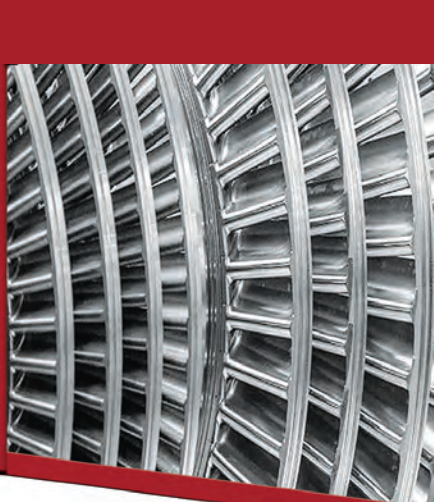
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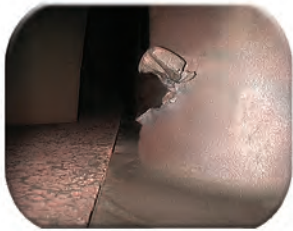
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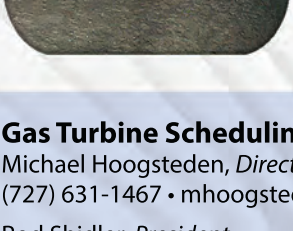
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Rick Ginder, *CEO*
(352) 262-5448 • rginder@advancedturbinesupport.com

Steam Turbine Scheduling & Technical Information

Bryan Grant, *Director of Turbine Engineering Services*
(207) 951-6031 • bgrant@advancedturbinesupport.com

Rod Shidler, *President*
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cle Power Plant.” It better be. The Energy Information Agency’s (EIA) US electricity demand forecast has shifted from a modest 0.9% growth to 2.0% annually in just two years. Large industrial loads account for 75% of the expected demand, as electric vehicle demand declines precipitously. At time of presentation, CCs were expected to average 70% capacity factor in 2025, a significant change from the 40% level in 2008.

Perhaps the most eye-opening chart is the one showing price indices for power plant components, e.g., if you need a transformer, you better be prepared to sacrifice your first-born. If you order an HRSG today, be prepared to shell out 50-100% more than you did in 2023. While COVID brought much manufacturing back to the US, even with tariffs, HRSGs are still less expensive to source overseas. Holding two balls in the air—the expected build-out and the average age of the HRSG fleet (~27 years)—should get your mind right about the coming nightmare in sourcing.

MODEL-BASED CONTROLS

While we wait for AI to make us all smarter, or at least richer from the buildout, digital intelligence and analytical tools built into the plant’s control system can be harnessed immediately. The presenter of “Consistent and Optimal Combined Cycle Operations” gives eight practical examples of how to “marry

the experience of the specific plant with modeling and theory.”

- Tracking cycling variability (e.g., shift-to-shift differences in fuel use for an overnight hot start).
- Model-predictive steam temperature control (to maximize ramp rates and reduce stresses from starts and ramping)
- Advanced steam bypass control management
- Duct burner optimization (reducing time to get duct burners on-line from around 75 minutes to 20 min with full automation)
- HRSG drum level pressure control
- Advanced pump protection
- Rotor stress management and optimal steam turbine startup.
- Procedural optimization/integration (analyzing operator actions).

These jam-packed slides are not for the faint of heart, but there’s a gold mine of operational improvements and cost savings embedded in them.

SAFETY WAKE-UP CALL

In an era when legal and liability risks prevent disclosures to wider audiences, user groups are to be especially commended for their forthright dedication to sharing on critical safety events.

A plant manager reviewed an incident during which a contractor was discovered in shock on the steam turbine/genera-

tor (ST/G) mezzanine deck. Contractors needed to remove current transformers for testing and were trying to pry open an access door which wouldn’t move pulling on the handle. Even with its 22 bolts removed, it wouldn’t budge. While they looked for a crowbar, the door blew open with 8800 lbs of force. Within minutes, fire and EMS personnel arrived on-site, followed by a local news reporter, police, and OSHA personnel.

The slides (not available at the Power Users site) review the plant response and OSHA interactions. But the post-mortem review points are most important:

- LOTO (lockout/tag out) only included electrical components, not the generator’s hydrogen cooling system.
- Pre-project brief did not specify that H2-carrying components were behind the access door.
- Contractors did not contact their plant sponsors before starting work after the scope changed.
- Contractors unbolted the door to gain access, rather than seeking a hold point to gather other specialists to determine the proper course of action.



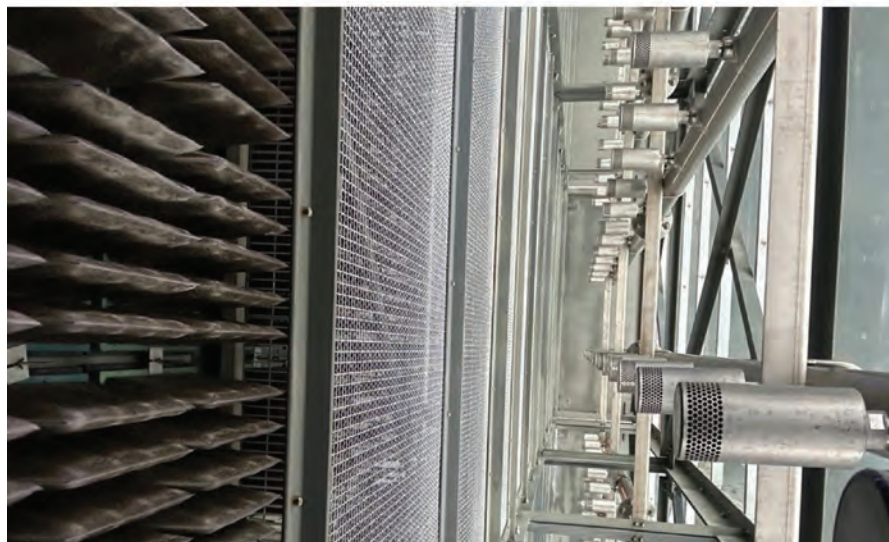
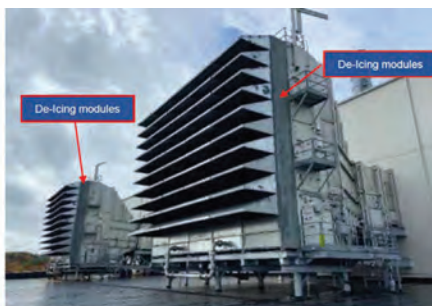
COMBINED CYCLE USERS GROUP

Roundtable discussions are a highlight of the CCUG program. One this year covered a round robin of topics, offering timely tips and reminders. For example, regarding high energy piping and pipe hangers, if you find a nut on the ground, don’t ignore it. Work into your plant “culture” an investigation of where it came from. If you have a water hammer event, review and inspect your paper hangers. Don’t wait for someone else to write it up. Have your people walk around with inspection vendors for “training. Do lunch and learns. Do drone inspections.

For buried tanks, make sure vents are operable and cathodic protection (CP) is sound. If you have carbon steel underground piping, you will have problems within five years without CP, noted one audience member. Annual general inspections are good practice.

One attendee related an incident when pressure regulators froze and failed, releasing 500 psig fuel gas “all over the plant,” almost blowing up the office building. So, check gas and line vents, whether bent over (to prevent rain intrusion) or straight. Rainwater gets in and can freeze. Check lightning arresters on H2 lines, and transformers for wet conditions (leaks into the building). Make sure the “good spare” is stored in dry, safe conditions.

During a segment on aux boiler layup, one attendee revealed his plant doesn’t lay up the aux boiler. Don’t be this plant! And



2. Slipstream of compressor exhaust is diverted in this piping array to an injector array (installed nozzles shown) just downstream of the GT air inlet to prevent icing during severe cold weather



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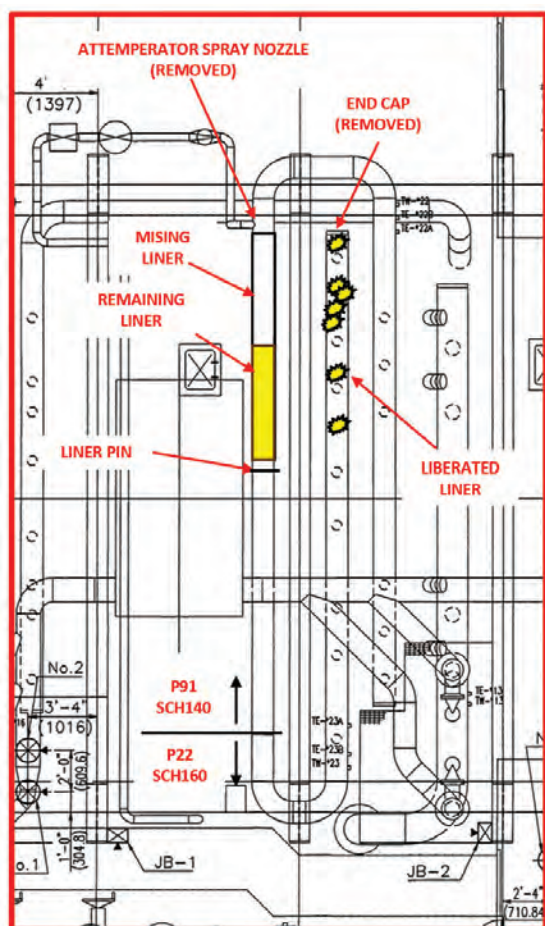
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3. Liberated HP attemperator liner pieces were discovered in the downstream piping, resulting in replacement of nozzle, steam/lance, and 80% of P91 piping, along with significant weld repairs



don't leave in wet layup for more than two weeks.

Another user mentioned that "the best project" his plant ever did was install a fast degas system for the H₂-cooled generator.

The last part of the roundtable confirmed the issues users are facing getting replacement components and parts. Turbines are 5-year lead times, GSU transformers 3-year lead times. One attendee lamented that L-0 ST blades now have 5-year lead times. Even smaller components like transmitters, control valve components, spray nozzles, and heat detectors were all mentioned as getting hard to find.

Stuff like 20-in attemperator lines are no longer "off the shelf" items. Single-point vulnerabilities "will bite you!" Plants are now responsible for getting parts the OEM used to source, often leading to use of "hand-me-downs." Even local contractors are running out of people.

However, as one user noted wryly, if you're willing to pay a 25-30% expedite fee, parts will magically appear from suppliers' shelves. Some vendors have "hold" programs in which you buy parts and the vendor holds them for a fee.

Users are rethinking outages and warning others to "get through the discovery pe-

riod as soon as possible." Where inspections were once staggered, users now suggest that you do as many as you can as early as you can to add lead time for planning outage events. Good contingency planning now means planning for two and even three outages in advance.

Have a "maintenance planning function." insisted two users, someone or a committee who "owns the plant" during the outage.

Calibration. You have to be grateful to a user who puts together a ~50 slide deck to help the CC user community understand and manage instrument calibration, the importance of which cannot be overstated as plant staffing continues to shrink and plants approach remote, unattended operation through automation (ultimately based on instrument measurements). To emphasize this point, the slide deck reviews several infamous plant failures rooted in poor calibration. Significant segment of the presentation covers modern calibration management software.

Key best practices listed in the last slide include establishing a fixed calibration schedule for every instrument based on whether it is critical, required by regulation or standard, or non-critical; deploy management software to track history and

schedules; ensure calibration traceability to recognized standards; document results and analyze trends; and train technicians on safe operating procedures.

GT inlet air anti-icing. Presentation is mostly a richly detailed photo montage of one plant's journey (update New York location) from an extreme snow and GT inlet-air-housing icing event in 2022 to an installed anti-icing system in 2023. The new system (Fig 2) "takes up to 5% of the compressor discharge (bleed heat) and diverts it to a 239-nozzle injection grid installed in front of the pre-filters."

Key features include hard stops on the control valves, auto-draining filters on the anti-icing instrument air supply lines, and fully operable inlet bleed heat (to bell-mouth), with the control logic permitting the IBH to override the de-icing system to ensure compressor safety.

Attemperator failure. A 2002-vintage CC in Missouri reported on a high-pressure attemperator failure occurring in 2024, during which the spray nozzle and the liner were damaged, with pieces of the liberated liner discovered well downstream (Fig 3). Repair sequence included replacing the nozzle and stem/lance and patching welding where needed; performing non-destructive examination (NDE) on all P91 and P22 pipe, replacing 80% of P91; cut/rewelding poor welds; and borescoping, accessing, and replacing the liner.

The silver lining (pun intended) was that repairing and redesigning the attemperator could recover lost ST/G output. Other slides detail the pre-failure operational situation, distinction between an attemperator and a desuperheater, and explanations of how both work, major equipment, risks from failures, tips on inspections, and failure prevention. Regarding the last, this plant increased inspection frequency from every three years to annually. Also, if your GT has been upgraded, make sure your attemperator design is still suitable.

CCUG VENDOR PRESENTATIONS

"Design for Emissions Stratification,"

Neal Holden, Vogt Power International

After a review of the SCR process and equipment, presentation explores causes of SCR under-performance, monitoring needs, and solutions, with a case study investigating NO_x stratification at the stack. Holden emphasizes regular catalyst activity testing, as it is a better predictor of catalyst replacement intervals than ammonia slip (a lagging indicator), and maintaining SCR operating temperature within 50 deg F of its target.

To address stratification, plant in case study added distribution grid hardware between the ammonia injection grid (AIG) and the catalyst, trimmed the baffles, modified the outlet duct and stack geometry, and installed a permanent grid of "test ports" (Fig

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4. Data from sampling/tuning grid installed on the downstream side of the SCR catalyst in horizontal HRSGs is used to create heat maps for adjusting AIG balancing valves, reduce ammonia consumption, and minimize outlet NOx based on average and localized values

4) for in-situ sampling and tuning.

During Q&A, about half the audience raised hands when asked if they tested catalyst samples. One user claimed his SCR had never been tuned, only cleaned, during its 23 years of operation. Others mentioned that high ammonia salts levels are being discovered because of sulfur levels in the exhaust from burning fracking gas.

“Sound Decisions: Using Ultrasound to Protect Plant Availability in Capacity Markets,”

Peter Mantel, Distran USA Corp

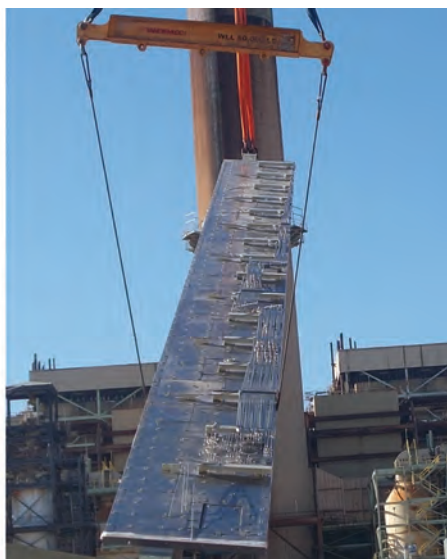
Move over snoops, soap sprays, and other ways to detect leaks. According to Distran, handheld portable ultrasound “camera” devices can check for gas leaks by converting the sound emitted into an optical image of estimated leak size, regardless of the type of fluid or composition. Background noise is filtered out. Devices can also detect partial discharges from transformers and electrical equipment. Leak detection is safer because the device works from 25 ft away (optimal distance). Some dangerous leaks, such as dry steam, are invisible to the naked eye (Fig 5).

Leakage flow is an estimate within +/- 30%, good enough to make informed safety and O&M decisions. Several people in the audience vouched for the devices, one saying they are “really good for air leaks and checking H2 lines.” Power plant applications include hot air from gas turbines, methane in fuel systems, condenser vacuum leaks, steam, and H2.

“Duct Burners Under Fire: Problems, Causes, and Solutions,”

Behnam Kholghi, HRST Inc

Seemingly anything that might go awry with a duct burner is covered in this 60+

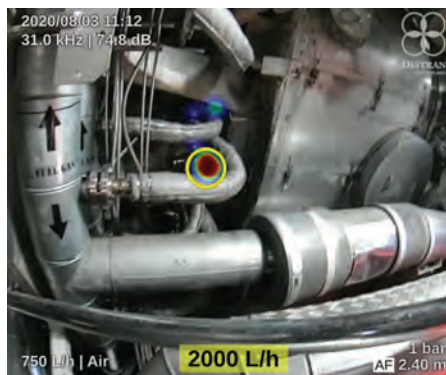


slide presentation, and that’s after the basic review of its purpose, location, and components. The photo gallery is a veritable no-cost guide to what to look for when inspecting your HRSG aux burners.

Two non-obvious recommendations:

- Conduct a CFD (computational flow dynamics) study after a GT upgrade. Mal-distribution of turbine exhaust can damage side wall liners downstream of the burner elements and flame holders, and cause coking.
- Add block valves and drains to prevent condensation from collecting in the lower manifolds when not operating (Fig 6). Moisture can cause burner element deformation upon firing after downtime when the cold moisture shoots into a hot lance.

One obvious, but obviously neglected, recommendation: Install better viewports so you get good eyes on flame shape and distribution, and potential impingement on pressure and non-pressure parts. Even better, consider installing video cameras on the



5. Methane leak detection in GT fuel distribution piping is just one of several applications (air, H2) for hand-held acoustic detection method based on pictured sensor operating up to 25 feet away

floor, roof, or walls for 24/7 monitoring in the control room.

“Enhance Technological Advancement with EMI Monitoring Diagnostics,”

Cutsforth

Monitoring electromagnetic interference (EMI) to detect incipient failures in large generators was first proposed in 1979 according to Cutsforth specialists. Over the following four decades, several large utilities progressively applied the concept to monitor generators, motors, transformers, and other large electrical components. Now, a plant in upstate New York is working with Cutsforth to convert ~50 plant-wide EMI detection system outputs into 20 diagnostic severity and urgency indicators and a color-coded production-risk dashboard (Fig 7) of potential consequences (e.g., outage duration) paired with a list of troubleshooting steps to inform the outage scope.

“Control Valve Repair & Maintenance: Best Practices for Combined cycle Power Plants,”

Dean Casey, MD&A

Some of the more salient suggestions from this imminently practical slide deck are: Perform valve stroking per OEM intervals to reduce oxidation buildup; invest in components with upgraded materials such as Inconel substitutes and stellite-lined bushings; invest in spare drop-in assemblies, along with proper crossheads and connectors, to compress the outage window; and adhere to clearance criteria guidelines.

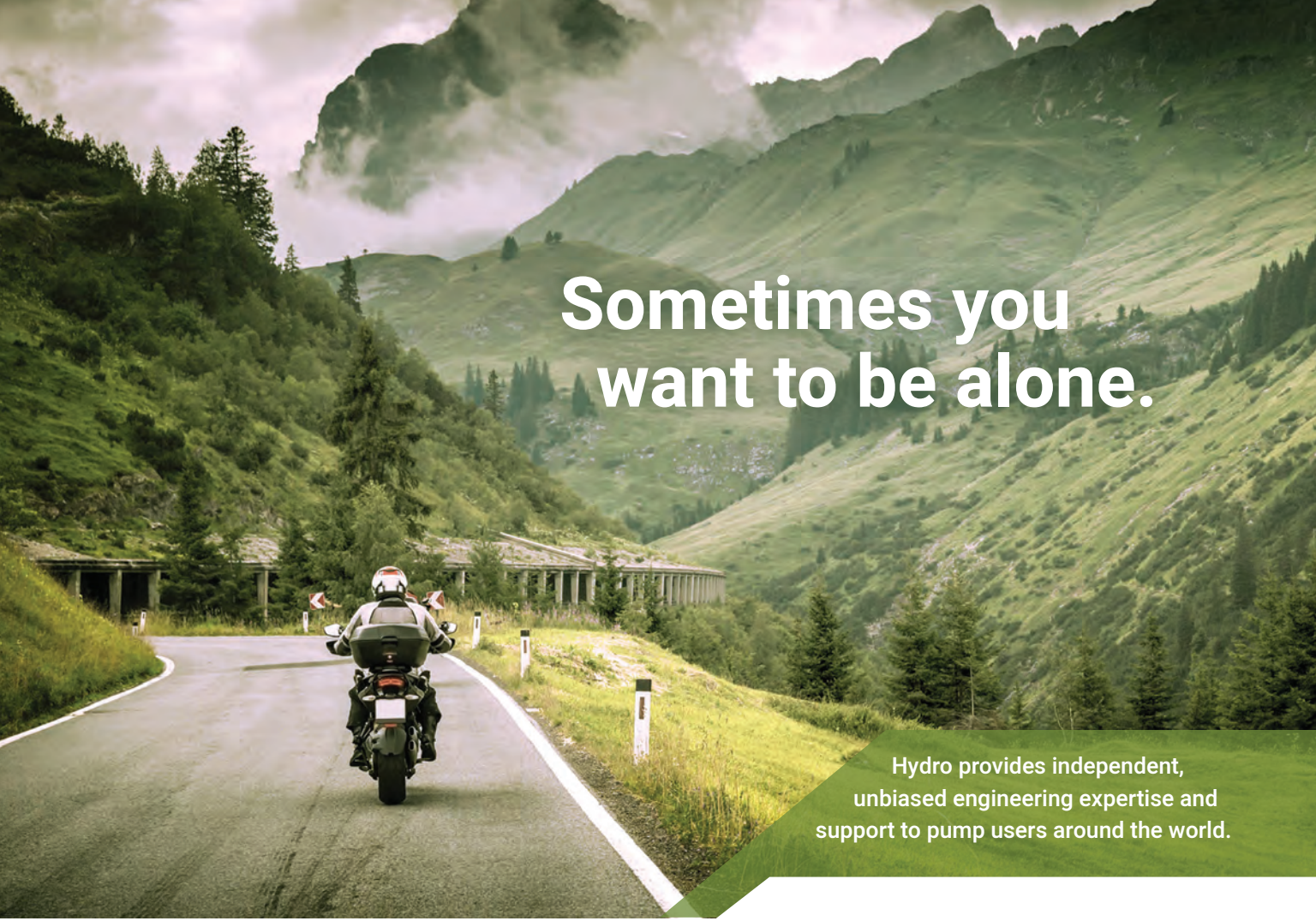
Slides also contrast pros and cons of outage self-performance checks, on-site work, and shop inspection and repair. General recommendation is to send ST and other critical valves to a shop at least every other outage.

“Primer on Steam Cycle Chemistry,”

ChemTreat

Presenter begins with fundamental process and design considerations for the cooling tower, condenser, and HRSG, then dives into chemical treatment needs, control and performance issues, key performance indi-





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cators (KPIs), condenser air-inleakage, and other matters. As the slide deck is a skeletal outline of the training material, it's probably best to contact ChemTreat for more thorough explication.

"GT Upgrades and HRSG Rerates,"

Greg Rueff, Vogt Power International

Several power plant presenters at past user events have expressed surprise at how their upgraded GT affected their HRSG performance. Given that market conditions will likely dictate many other GT upgrades, this slide deck is a must-read. Just one concern which surfaced in a case study of a 58-MW increased GT output: The original HRSG design was based on the 1998 ASME PTC code, which was revised in 2021.

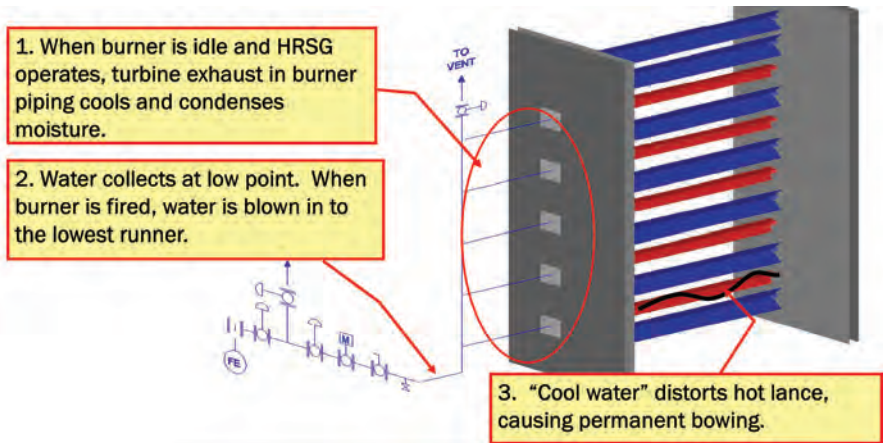
After thermal modeling was completed in this case study, every HRSG pressure part had to be analyzed, including every weld on every branch connection and every thermowell. The HP attenuator saw a 74% spray flow increase, the reheat attenuator an 84% increase. The former required a few upgraded components (nozzle, control valve), while the latter was able to accommodate the changes but was brought up to the current code anyway, with the addition of a drain pot for condensate removal. Several modifications, detailed in the slides, were also made to the HP drum.

While this case study is acknowledged to be an extreme example of an upgrade/rerate, it is still prudent to undergo a thorough HRSG evaluation. For example, general maintenance work in which the "design" does not change is a repair and can be conducted to the original code, but if an aspect of the design changes, it must be brought up to the current code (though there is disagreement among officiating parties).

"Five HOP Principles: Your Roadmap to Operational and Professional Success,"

Matt Barnes and Rene Carabantes, MD&A

The topic of developing safety and high-performance cultures at plants should



6. Condensate collected at low point during burner downtime shoots into the hot lance when fired, causing permanent bowing. Best solution is individual

never get old. There's always more to learn and more to be reminded of. The five principles of "human and organizational performance (HOP) are:

- It's okay to make a mistake but unacceptable not to learn from it.
- Blame fixes nothing - shift the focus from blame (not the same as accountability) to open and honest learning.
- Context drives behavior, context being such factors as management systems, leadership, corporate mandates, individual personalities, and expectations.
- Learning and improving is vital, and must translate into actions
- A leader's response matters - e.g., do more asking employees what they need, less telling them what to do.

Balance of the slides review a case study applying HOP at a plant in Georgia.

"LCI Preventative Maintenance & Issues,"

Jim Zeleznik, MD&A

Presenter offers a system overview of the load commutated inverter (LCI) and handy checklist of ten preventative maintenance tasks for one OEM's water-cooled static starter and common issues. Know that

UCVx control boards have been failing at an elevated rate.

"Case Studies from Field Inspections of Formed Tees at Large CCGT,"

Tetra Engineering

General recommendation here, based on programs at five plants (four with commercial operating dates between 2015 and 2023 and one from 1999), is to have a formal inspection plan in place for "formed Tees" in HRSGs, one that is separate from the critical piping system (CPS) inspection and not abridged to fit into a larger outage scope. A typical 2x1 F-class GT facility can have more than 20 large-bore tees which operate in the creep regime. While the main failure culprit being searched for is creep, presenters say they often find other types of damage.

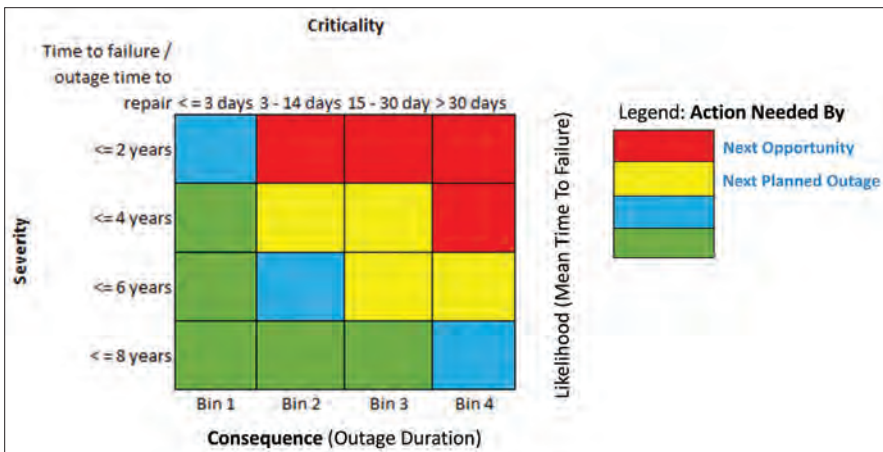
The concerns with such tees arise from EPRI work showing failures being experienced at less than 100,000 operating hours in radiant boilers operating at much higher pressure and stress levels.



Lessons learned from a steam turbine forced outage

is an example of why every owner/operator should have people at these conferences. The HP/IP incident in question involves two and a half rows of rotating blades liberated at the platform, four rows of stationary blading missing 10-60% of airfoils, rubs observed on the lower halves of the HP seals and packing, and a total of 15 rows of rotating and stationary blading needing to be replaced (Fig 8).

The OEM root cause analysis (RCA) is a real mouthful but goes like this: Cold misalignment led to hard rubs during startup which generated excessive heating of the shrouds, leading to loss of pre-twist in the blades because they were more susceptible to the high cycle fatigue by which the blades were liberated. Addressed as part of the re-



7. Risk dashboard for large electrical equipment - generators, motors, transformers - is constructed based on on-line continuous collection and processing of EMI data

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mediation plan are the misalignment, seals and clearances, LVDT position errors, insulation, steam blows, and oil flush. Reams of operating data ahead of the failure are also included.

Worth noting is that this ST unit was commissioned in 1957, then repowered with the conversion of the old fossil plant to a 4x1 CC in 2003. More recently, when concerns with rotor bow (run-out), creep/embrittlement, and inner casing cracking surfaced, a new HP/IP rotor and inner cylinder were installed in early 2024. While the failure occurred October 1 of that year, several operating hiccups were noted prior, supported with much operating data ahead of the failure.

In a stellar example of collaboration, four utilities got together to develop a scope strategy for a D11 high-pressure/intermediate pressure (HP/IP) ST replacement. Among them, the utilities operate 18 D11 units. Slides review common end-of-life issues such as outer shell thermal stress, creep, deformation, cracking, and leakage; rotor bowing, creep strain in dovetails, and LCF at wheel fillet; and diaphragm dishing. Each utility had different motivations for the replacements.

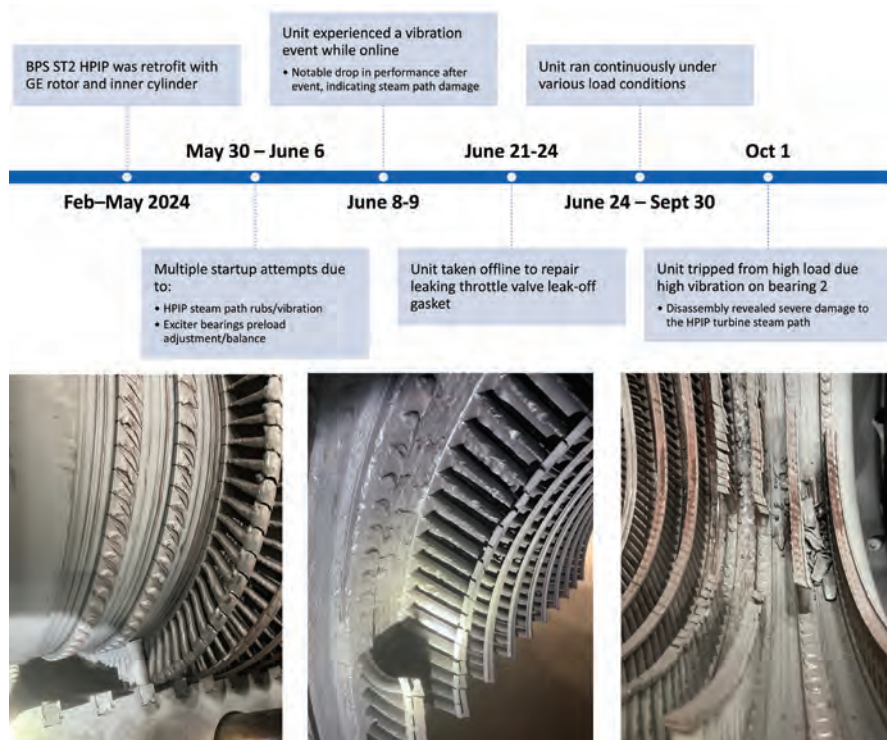
The lessons learned slides should be invaluable to any users contemplating such a replacement. Replacements for these collaborators are scheduled progressively between fall of 2027 and fall of 2030.

Creep life management in steam turbine casings was the subject of the kick-off presentation by an EPRI specialist. "Time-dependent (creep) damage is an emerging concern in casings across the thermal fleet," he said. Unfortunately, the onset of creep damage (cavities) is "impossible to detect." He aimed to "debunk some of the earlier assessments and 'creep-fatigue claims' and decouple creep from fatigue. Both can be observed simultaneously.

Current casing materials are not meeting performance expectations, he said. Essential question: "Can you explain how your casing got to its current condition?" Put another way, are damage mechanisms in your casing being confirmed or assumed? For example, creep damage detected in the casing may be localized given its sensitivity to temperature and stress.

EPRI has fitness-for-service material data sheets supported by two decades of analytical data (data OEMs and service providers do not have) and an active investigation program for D11 casings and repair techniques and strategies. The slides offer some of this data and a few case studies.

A few points which could make you nervous about your aging casing, such as 15% increase in stress can lead to a 2x change in life, a 25 degF higher temperature will decrease casing life by a factor of 2, sub-surface creep damage may exist despite an undamaged surface, there's no benefit from post-weld heat treatment on creep perfor-



8. Damage was discovered to HP/IP following a trip six months after unit was retrofit with new rotor and inner cylinder. Timeline suggests early issues following retrofit, but 3+ months of uneventful ops under various load conditions before trip

mance in casings, and it is impossible to rely on NDE alone for condition monitoring.

The specialist also focused on filler metals for repairs. Matching filler metal strength to the repair material is not a trivial exercise. Higher strength filler material can actually accelerate damage evolution, especially in degraded or damaged material which was not removed during the excavation process.

While some of the slides require a background in metallurgy, the overall message is that you should have metallurgists guiding your decisions on aging casings, not just OEMs and service providers.

Last stage blade droplet erosion was addressed by a second EPRI specialist. Part-load operating conditions increase relative droplet velocity by up to 40% and increase erosion rates by a factor of 16. Exhaust hood sprays are of particular concern.

Damage measurements, usually taken manually, are often very subjective, he argued, and it is difficult to develop generalized predictions from specific sets of turbine data, although it can work better under steady state operation. During the Q&A, one user noted a special concern with erosion at the Z-lock attachment.

From the commercial end, OEMs typically do not recommend weld repair; they'd rather sell new blades, and many users prefer the conservative option even if replacement is premature. Repair service firms don't share their repair techniques or experiences so it's difficult to discern repair efficacy.

EPRI is pressing hand-held 3-D scanners

into service for more accurately assessing droplet erosion damage on trailing edges, blade tips, Z-lock shrouds, and other parts. Goals are to aggregate the data into "erosion maps" that could lead to advanced evaluation of erosion rates in specific areas.

As with the talk on casings, the slides are numerous, dense, and busy, suitable for a day-long workshop. They cover damage mechanisms and influencing factors, damage characteristics and measurements, consequences of droplet erosion damage, erosion damage prediction and assessment, and blade restoration techniques.

It's important to note that weld-repair techniques for last-stage steam turbine blades date back to the early 1980s in coal- and nuclear plant steam turbines, so there's a wealth of knowledge and experience to tap into if you're interested in avoiding wholesale blade replacements.

ST rotor crack repair. Speaking of weld repair, ST experts from one of the nation's largest O/Os reported on a rotor crack repair applying the guidelines in EPRI's "State-of-the-Art Weld Repair Technology for Rotating Components, Vol 1: Weld Repair of Steam Turbine Discs and Rotors." The LP ST (part of a 1990-vintage peaking CC unit limited to 10% capacity factor because of environmental restrictions) is described in the slides as an "unusual configuration" requiring "unorthodox lifting."

During a 2017 inspection to locate the source of air in-leakage, specialists found heavy deposits on rows 1-4. Plant continued to operate (low annual hours) until a vibra-

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9. Example of damage to blade rows 1-4 of the LP steam turbine discovered during a 2025 inspection. EPRI guidelines were followed for rotor weld repair



tion trip event in January last year. Upon inspection, significant damage to stages 1-4 was discovered (Fig 9). The blades were replaced. Balance of the slides offer a detailed pictorial with diagrams of rotor repair, including prep, machining, welding, post-weld heat treatment and finishing; blade replacement, high speed balancing at a facility in Houston; and reassembly.

ST/G alignment challenges. A third EPRI presentation stressed that the time required for ST/G alignment measurements and corrections are often under-estimated. Alignment issues are 3-D in nature with an almost infinite number of possible options for addressing them, and great difficulty arriving at their root causes. For example, bearing vibrations caused by misalignment are often addressed through field balancing adjustments during startup, but this may conceal the root cause.

Slides review alignment main activities, preparation and planning (review of operating data, gathering records, tooling and special equipment, etc), lessons learned and best practices, etc. Another interesting caution: Using advanced tools for measurements do not necessarily resolve alignment issues.

Stop valve control valve (SV/CV) lessons learned, presented by a representative of a large O/O and an MD&A specialist, begins with troubleshooting issues arising during daily valve tests, leading specialists to suspect the integrity of the CV springs. Subsequent outage activities include cleaning scale off the valve discs and balance chambers, and replacing the valve springs, which exhibited a free length 1/2 in shorter than in the “new” state.” After this work, the valve passed the test. A modification of the balance port may also be conducted in the near future.

Also discovered (and depicted in photos) were solid particle erosion of the valve seats and valve stems and thermal fatigue cracking of the valve body. General takeaway: When daily valve testing is not successful, remove the valve from service.

In diaphragm crack discovery and repair, an O/O specialist teamed up with a Sulzer specialist to review stage 23 dia-

phragm issues and repair from a 2002-vintage 120-MW A10 ST which had changed operating profile in recent years from base-load to peaking.

Initial discovery and NDE results are captured in a few slides, then mitigation options assessed. Shop inspection revealed linear indications from 1/16 to 3 1/2 in. at the welds between the vanes and inner/outer webs, linear indications in the stationary airfoils, cracks in the leveling blocks, and heavy damage to the anti-rotation slot in the lower half of the diaphragm. Oddly, the vanes are hollow. No previous cracking of vanes had occurred.

The repair process, accepted as temporary to extend component life, included reverse engineering and design modifications to reduce thermal gradients during starts, stops, and load changes.

Failure, mods, and material analysis of L-0 ST blading (Siemens design, 10 m2 and 6.9 m2 length) traces need for accelerated precautionary inspections of these blades to a blade root liberation event in 2005. Perhaps of most interest to users is that the utility presenter developed its own PAUT (ultrasonic) inspection protocol and applied it to two units every 200 starts from 2006-2013 with no indications found. Other slides focus on findings and analysis in 2013 of the unit which experienced the 2005 event.

The OEM supplied the utility with new

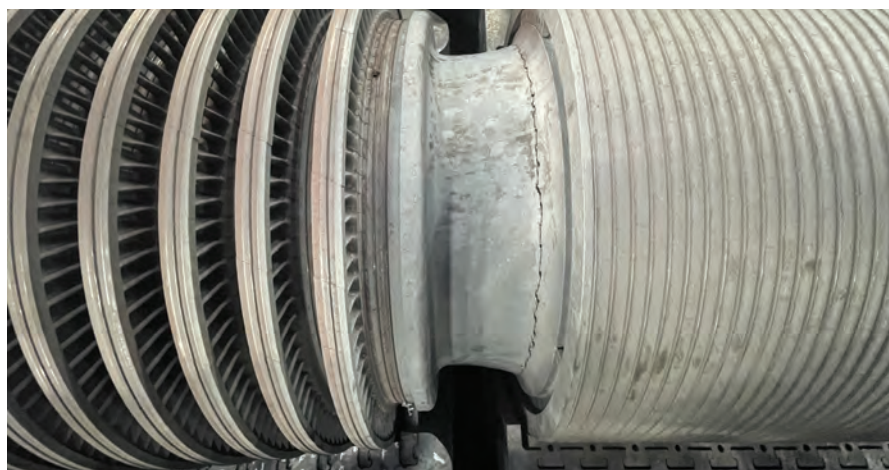
sets of redesigned L-0 blades, together with new guidance to increase allowable starts between inspections to 400 starts (side exhaust) and 500 starts (axial exhaust). Assuming the guidance would be conservative, the utility conducted material testing of the new blades to determine if inspection intervals could be modified. Crack growth rates between the new and old material (X5 and X10) were projected to be similar, so inspection intervals should be similar, too. However, time to crack initiation of X5 was greatly improved. Goal is to optimally manage crack initiation and growth, given high starts on these units, and long lead times on spares if indications are found.

The good, bad, and ugly. You may be unsure of where the “good” is in this slide deck but if you have “wreck on the road” viewing fantasies, this deck features a huge circumferential crack (Fig 10) in an undesignated ST rotor, last stage blade erosion near the platform, missing, liberated, and deformed LP blades, and blades which look like gravel went through them along with the steam. If you have a new green ST engineer on your staff, this might be the slide deck which “puts the fear of god” in him.

Remaining life assessments, presented by Entrust Solutions, offers a generalized roadmap, focused on the areas of highest risk (blades and rotors), and broken into phase 1, an asset review, and a phase 2 comprising detailed engineering analysis. Results are prioritized, given scores and ranked, and fed into a multi-year capex plan. Some specific points: not all failure modes are linear, changes in duty cycle and site operational and maintenance practices must be factored in, and more detailed outage diagnostic techniques may be needed as the unit ages.

Entrust has conducted over 500 ST/G life assessments, with a higher level of requests from insurers in recent years. Data attributed to EPRI and FM Global shows that the highest risks stem from flow-path components, specifically blade/dovetail cracking.

A case study from one plant-wide assessment summarizes risk-based condition of



10. Huge circumferential crack was discovered in this ST rotor



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plant components using available inspection data and walk-down info. Table showing unplanned maintenance risks by component, issue, timing, probability of occurrence, and recommendations may be especially revealing.

STUG VENDOR PRESENTATIONS

“Can the Steam Turbine Support Daily Cycling?”

Steve Radke and Thorsten Wold, Siemens Energy

Answer to the question is yes, if your unit includes a “world class stress controller” managing predicted load margin and optimizing GT ramp rate, and a “high-powered static frequency converter” for fast acceleration. According to the OEM reps, up to 85 MW/min ramp rates are possible in an automated start-up sequence. The full “flex plant design” can achieve a hot start in 20 min.

“CC Performance Testing and Steam Path Audit Case Study,”

Jim Miller, MD&A

Improving turbine cycle heat rate not only leads to significant annual cost savings but informed decisions for prioritizing maintenance. As a rule of thumb, a 1% step change in turbine efficiency at valves wide open should cause an investigation. Two primary aspects of a performance improvement program are (1) conduct as accurate an efficiency test as possible before and after the audit, benchmarked to a reliable reference, and (2) inspect the steam path off-line to identify deficiencies and quantify economic impact.

Examples of typical as-found sources of performance loss include seal leakage, solid particle erosion, deposits, foreign object damage, water erosion, changes in blade trailing edge thickness, surface roughness, and flow changes from HP turbine inlet area alterations. Other common issues which surface are damage to first reheat stage, inlet seal ring leakage, and distortion in packing casings and diaphragms. Results from a case study round out the slides, with a breakdown by issue of performance impact and economic benefit/cost ratios (Fig 11).

“Oil-Your Hidden Asset!,”

Eddie Rowland, C.C.Jensen, Inc

“When do you need to change your oil?” the presenter asks, but not before urging his listeners to treat oil as an asset, not just as a consumable replaced on a fixed schedule. While go/no-go answers for the question “don’t exist,” presenter offers some good guidelines based on common tests, such as viscosity, total acid number, additive depletion, particle count, ASTM E2412, MPC membrane, ultra-centrifuge, water/moisture, foam, demulsibility, RULER, and RPVOT. Maintain it, monitor it, clean it, and extend its life, presenter concludes.

	As-found			As-left			Recovery		
	Total Loss (kW)	Heat Rate Degradation (BTU/kWh)	Annual Fuel Cost (\$)	Remaining Loss (kW)	Heat Rate Degradation (BTU/kWh)	Annual Fuel Cost (\$)	Recovered Power (kW)	Recovered Heat Rate (BTU/kWh)	Annual Fuel Savings (\$)
Interstage Packings	439	9.1	40,967	47	1.3	5,808	392	7.8	35,158
Tip Seal Strips	1,493	33.0	149,035	32	1.8	8,091	1,461	31.2	140,944
Root Seal Strips	312	5.5	15,886	238	4.2	11,557	74	1.3	4,330
End Packings	944	14.7	66,561	4	0.1	502	939	14.6	66,059
Surface Roughness	1,937	43.6	196,960	1,351	28.9	130,734	585	14.7	66,226
Solid Particle Erosion	95	2.6	11,626	0	0.0	0	95	2.6	11,626
Foreign Object Damage	638	0.6	2,818	0	0.0	0	638	0.6	2,818
Total	5,857	109.1	\$483,856	1,673	36.3	\$156,693	4,184	72.8	\$327,164

2.2% decrease in power from as-found steam path deficiencies

1.0% decrease in heat rate from changes made during the outage

11. Gains in MW output and heat rate improvements are delineated in this case study for specific corrections made after a steam path audit

“Untapped Efficiency: Steam Turbine Packing Rings and Seals,”

STAR, a PowerParts Group Company

Presentation reviews why packing seals exist in an ST; how they affect efficiency and economics, especially for baseload machines; issues which arise over time, such as axial rubs, distorted diaphragms affecting seal clearances, diaphragm dishing/creep, axial tilting, and others. Last set of slides explain advantages of company’s “sensitized” packing over conventional designs.

“D-11 Retrofit and Valve Upgrades,”

David Hicks and Kevin Roy, MD&A

First part of the deck describes the characteristics of the D11R (D11 retrofit) product and the fleet problems it addresses. Characteristics recounted include a double shell (full inner casing and cooling cell on upper outer shell); HP/IP rotor with higher rotor stiffness, excellent stability and vibration characteristics, higher creep and fatigue strength, and designed for modern CC cyclic duty; stationary vanes (reaction design) which avoid dishing and enhance efficiency; and higher efficiency steam path.

Second part of deck lists valve upgrades which address oxide formation and stem binding, erosion, low cycle fatigue (LCF) cracking, integral seat restoration, and hot swap assemblies.

“Repeated Challenges for Steam Turbine Outages,”

Tim Midgett and others, Viking Turbine Services

Outage issues discussed at length, along with case study examples and illustrations, are D11/A10 shell tap studs (e.g., thread relieving), LP inner casing horizontal joint erosion and bolt hole damage/repair, A10 N3G3 packing casing distortion (accelerated dishing with weaker materials), N2 packing fit cracks (unplanned repairs), D11 HP/IP horizontal joint blue checks, atmospheric-relief-diaphragm (ARD) assembly issues, main steam valve issues and repair planning (main stop/control valve and reheat valves), and D11 creep. There’s significant verbiage on these slides so think of it as more of a guidebook in slide deck form.



Planned and emergent field replacements and repairs are top of mind for most every O/O with a sizable GT fleet. A representative from a Florida utility covered experience during a major FA.03 to .04 upgrade outage in 2024 at an 1100-MW 4x1 CC in commercial operation since 2003-2004. The title of the preso, “Two Fields Down, Two to...Oh!,” hints at what’s in store for readers.

The rep began by stating that “these fields [Hitachi generators] were never pulled” over their two decades of operation and “we could have been better at borescope inspections” over that period, even though vibration levels were never exceeded or caused a trip (robotic inspections were done). Each of the attached GTs had around 3000 starts.

Because shorted turns were detected ahead of the planned shutdown, the fields were pulled as part of this outage to evaluate suitability for service. Pre-outage, one unit showed a clear correlation between bearing vibration and field current after specialists evaluated flux probe readings, field current, and VAR test data. One other unit also revealed moderate indications from flux probe readings, while the other two showed only minor indications. Check out the slides for detailed graphs and field evaluation of data.

To avoid prolonging the outage, specialists elected to exchange fields on the two more troubled units. Other inspections, which resulted in the other two fields having to be replaced, are reviewed pictorially in the slides.

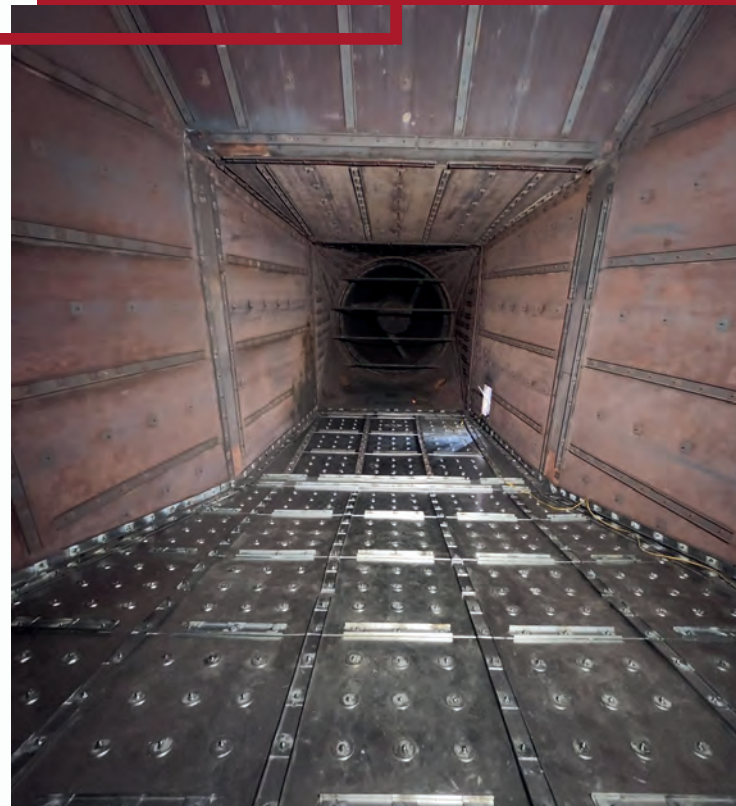
That experience translates into the first big lesson learned: Conduct BIs during minors to evaluate end turns. The second big lesson learned: Transmission planners may require fresh analysis to ensure the NERC MOD-026 and MOD-027 model constants are the same.

Generator core damage discovered after a BI minor was reviewed by a southwest US O/O rep. You’ll want to check out the

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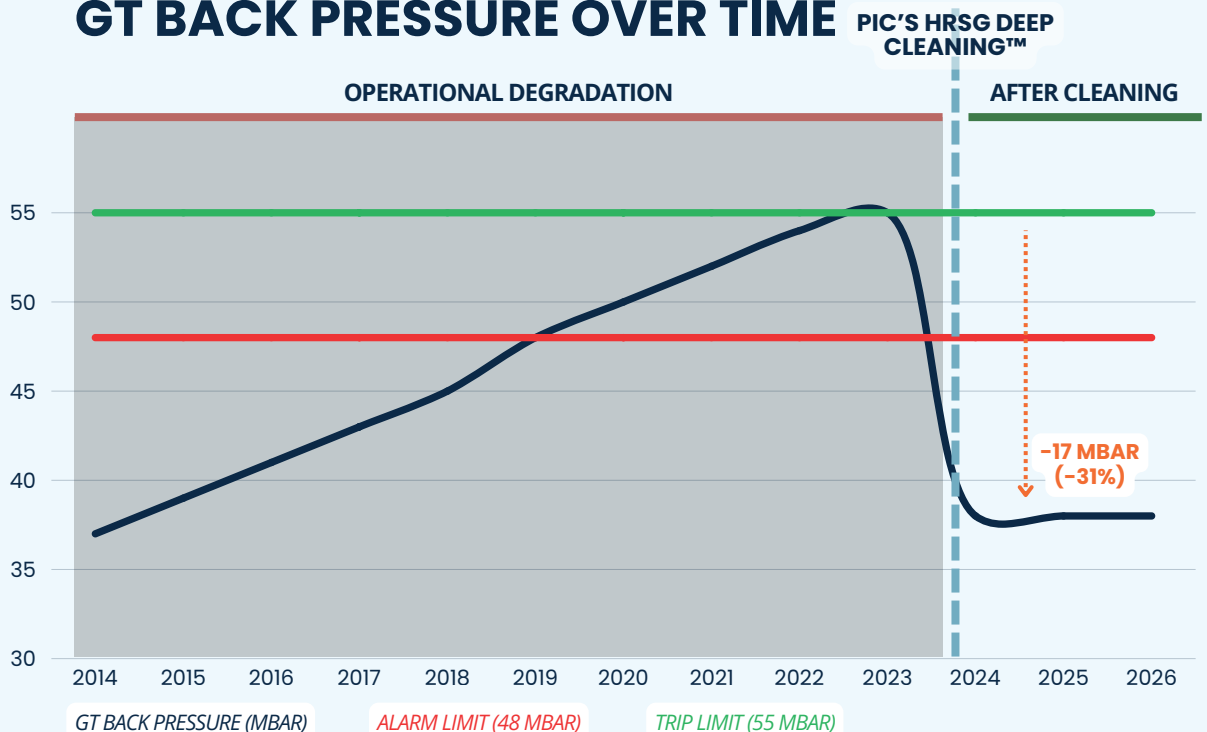
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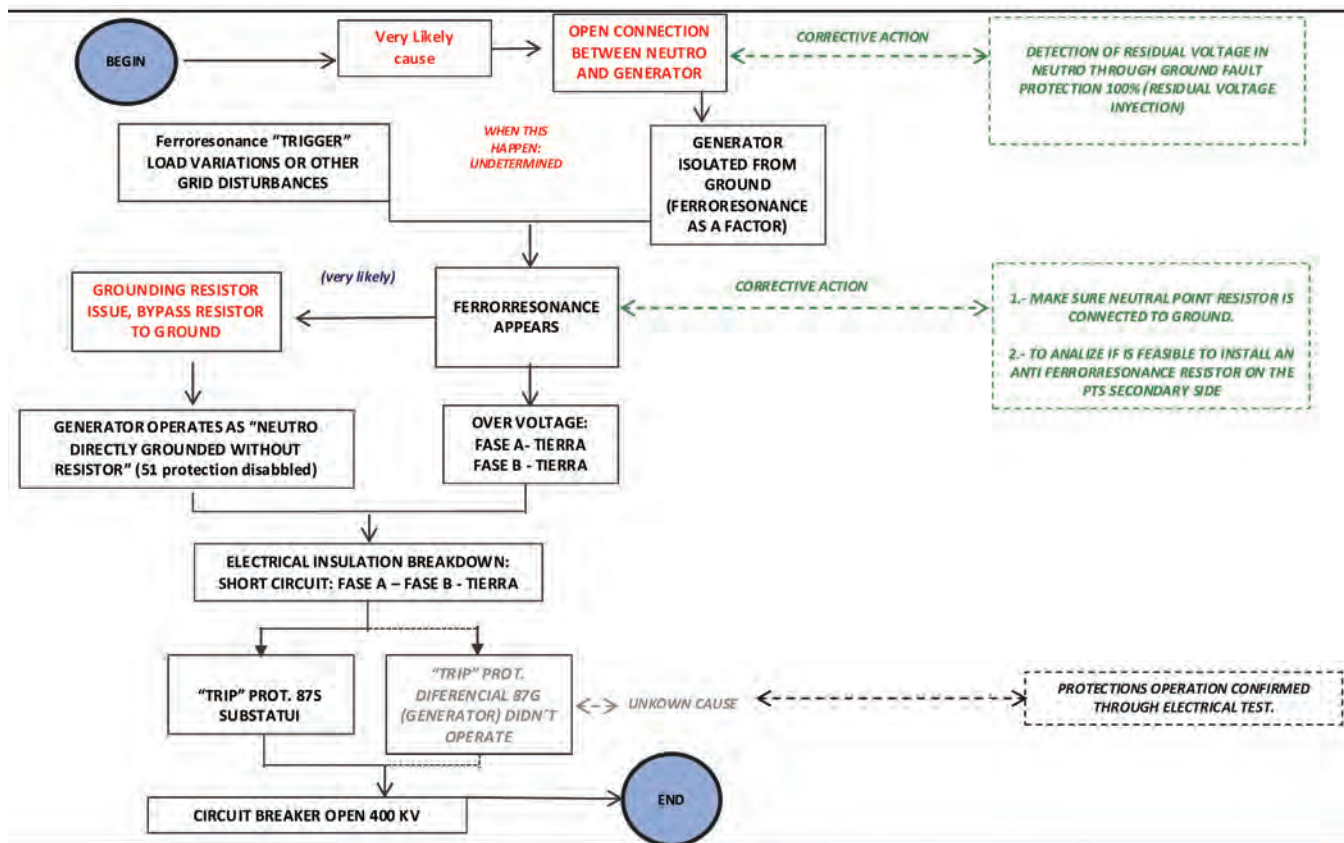
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12. Pre-trip and outage sequence of events were identified through a troubleshooting process, with corrective actions shown in green

pictorial to see how 70% of stator iron could be damaged, with no deviations in output or temperature prior to the shutdown, nor any evidence from the PI historian.

Needless to say, a 5-7 day BI turned into a 35-day outage, after a contractor inspecting the field body first noticed dents and scratches along the surface, then found severe damage to the core and field body. Metal objects were observed on the core iron and stuck in between the vent ducts. Later, 11 metal pieces were found inside the core. The collector end was intact, as revealed by damage maps (see slides).

Apparently, what happened was a pair of channel locks left by a millwright during a Fall 2021 outage found its way into the core,

even though no core repair work had taken place. This is articulated as a foreign material exclusion (FME) process failure. A millwright has to be inside the core to guide the field back in, and the channel locks either fell out of a pocket or were placed on top of the field and not reclaimed. Corrective actions taken to avoid future FME failures are listed.

Balance of slides review the repair plan, prep, iron core grinding, shop field inspection and rewind, and post-repair tests. Question, perhaps rhetorical, asked at the end: "Did operators hear anything bouncing around in there during their walk-arounds?"

In-place machining of collector radial leads was tackled by an O/O in Texas,

slides essentially providing a pictorial of inspection, testing, and replacement of both inboard and outboard leads and associated hardware. Although a prior visual inspection showed no obvious signs of overheating, tracking or distress, the outage plan included replacement, along with H2 seals, which had been responsible for an increase in forced outages within the fleet.

Troubleshooting a generator line-side failure could have been named, according to the Italian O/O rep who delivered the talk, "how troubleshooting can be complicated if you don't have enough information."

Summary of the salient lessons learned include:

- Make sure 100% of the generator is protected against ground faults
- Verify routine relay protection systems
- Inspect grounding systems as part of routine maintenance
- Make sure disturbance registers work properly
- Check the integrity of resistors located on top of the generator neutral connections
- Spares are key to prompt return to operations.

The sequence of events (Fig 12) which led to the ST/G trip and subsequent 12-day outage; the associated inspections, troubleshooting logic, findings, and thought processes; and the recovery plan and repair process are all explained in great detail, with very helpful diagrams, in the slides.



13. Side by side comparison of damaged vs undamaged radial (left) and axial (right) leads. Damage was discovered after ST trip on high vibration in bearing No. 6 and exciter bearing



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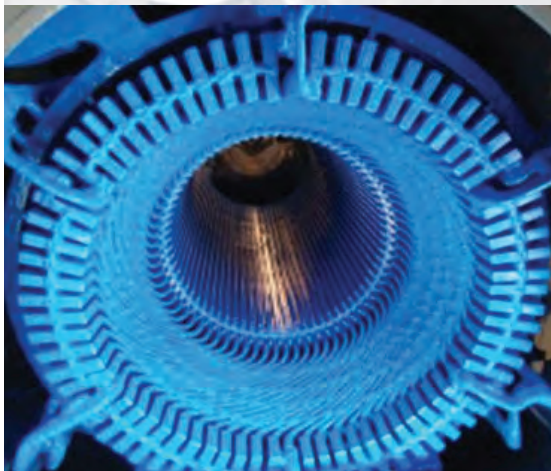
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Stator Rewinds

- Winding cycle times expanding
- Backlog of existing winding production grows
- Consider purchasing bars for stock

VPI'd Stator Owners

- Numerous VPI stator failures since 2017!!!
- Ask us how to test, and how to plan your rewind



AGTServices is currently looking to purchase a new or used, operational or in need of TLC, GE Schenectady-built 7A6 air cooled generator field. Please contact Jamie Clark.

jclark@agtservices.com

A bowed stator core in a model 7A6A 100-kVA air-cooled generator (frequently cycled) was the topic of a presentation by a western US utility. Big concern here was whether the same issues would be found with two other similar units. Evidence leading to a thorough investigation were increasing annual partial discharge readings over the years, high voltage testing in 2021 (very low PI values and significant DC leakage above 22 kV), and subsequent visual inspection, all of which suggested core sagging at the turbine end with a peak deflection of 78 mils.

Other findings include: Knife test indicated adequate core tightness, some support plugs were installed behind the core, and ElCid tests revealed no problems with the core.

Engineers decided to perform a core loop test, verify tightness of several through-bolts, and evaluate prior operating data, specifically vibration and stator temperature. One bolt broke away at 1535 lbs force, but the other three were tight. All other through-bolts were checked and found tight. There were no significant temperature changes; random high vibrations on the generator forward end could not be correlated.

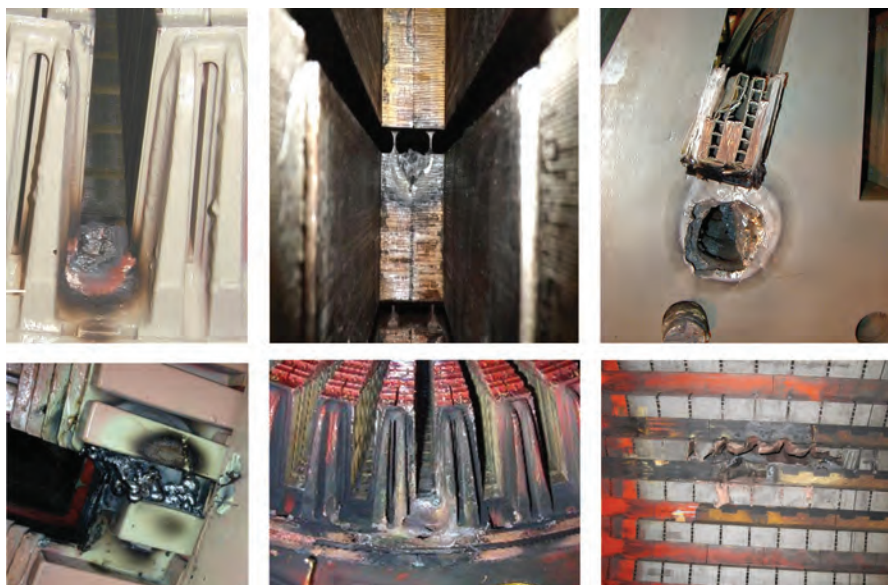
Since no broken welds of key bars to the web wings were noticed, plant decided to do a stator rewind, with additional flat fillers (with side ripple springs) at the turbine end of the stator, with semi-annual partial discharge (PD) monitoring. First four months of operation showed no abnormal vibrations and normal stator temperatures.

Critical questions: (1) Were the support keys underneath the core engineered properly, (2) why were issues not addressed in previous OEM reports, (3) was core restacking required on this machine, and (4) will the same issues affect two other units on-site of the same vintage and manufacturing location?

Generator inspection troubleshooting is a high-level overview of tips and traps by an O/O responsible for hundreds of machines. Some bullet points and reminders:

- Electrical testing only indicates an issue exists; visual inspection will identify the issue and location.
- Finding an issue “right before” failure is exceptionally rare
- Photograph everything during an inspection and include an object for scale when possible.
- Balance of slides are photos with examples of the types of indications likely to be found.

Generator rotor main lead failure. Subtitled “magnet madness,” a rep from one of the largest O/Os in America discussed a recent failure of a permanent magnet generator (PMG) exciter, discovered after a steam turbine trip on both bearing No. 6 and exciter bearing high vibration. Operators reported “smoke on turbine deck coming from the PMG.”



14. Failures with generator core components are plaguing the industry, according to EPRI, and are associated with insurance claims involving expensive and outage-delaying offsite repairs or restacks

Incidentally this failure occurred only five months before the conference, proving the willingness of many users to share as soon as possible on events which could affect the entire community. I mean, you really can't say enough about the dedication of these guys and gals.

The exciter was disassembled, with signs of rubbing on the stator and magnet assembly, so the PMG was sent to a motor shop for testing and repair. Then the 0-pole covers were removed, isolating the generator rotor from the exciter. A “hole” was found on the 180-deg pole at a damaged radial lead. The OEM had no replacement leads available and recommended that the rotor be removed and sent to their shop, but there was no shop space right away.

The balance of the slides review how the plant came up with a “workaround repair” for the damaged radial and axial leads (Fig 13) on site to return the unit to service as safely and quickly as possible, while waiting for the OEM's replacement parts. Though these are seemingly small components, the repair and recovery was not straightforward, as you'll see in some of the close-up photos.

Meanwhile, the exciter was disassembled and tested, with acceptable results, and the PMG stator cleaned and tested, also satisfactory. However the magnets suffered impact damage from the vibration trip. Thus began the “magnet madness.” The vendor could not source magnets in a timely way and the PMG was shipped back to site to attempt repair. Finally, a magnet supplier was found who would test the magnet and supply new ones - in 13 weeks. Plant found a temporary AVR (automatic voltage regulator) to supply power to the exciter.

The PMG was later reassembled, with balance weights added to compensate for

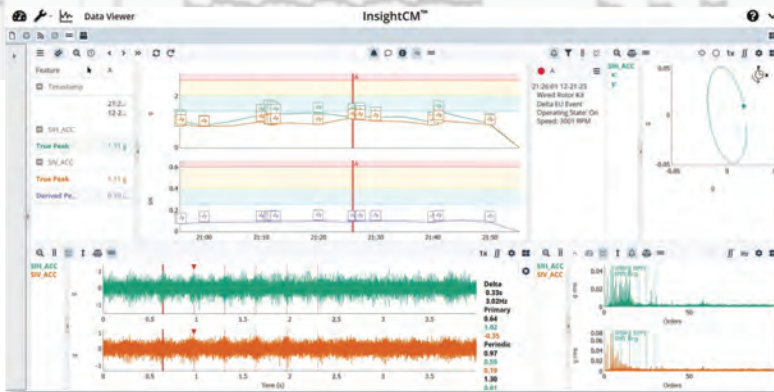
mass lost during grinding, then pressure tested with the new radial lead. This still isn't the end of the story for which you'll have to check out the slides. Fortunately, it has a happy ending.

Retaining ring pitting, rotor inspection and repairs, TIL 2256 (rotor slot liners and top U channels), and TIL2370 (head insulation and G10 liners) were addressed by a representative from a Texas plant. A team of third-party services reps were involved in the work. Summary of the work (slide deck has photos and details):

- Generator rotor was removed and shipped to the shop for rings-off inspection and testing.
- Excessive pitting was found at contact points within the dampening fingers and shrink fit area. Decision was taken to replace the two retaining rings.
- Top U-channel insulation was replaced due to cracking in the top corners (TIL2256)
- Rotor wind, head insulation, and titanium liners were replaced with new insulation and G10 liners from the OEM (TIL2370).
- Damper rings and fingers were found in poor condition (most of the silver plating was missing), removed, and sent to a local vendor for refurbishing
- Rotor was reassembled as shipped to another facility for high-speed balance and overspeed tests.
- Rotor returned to site, reassembled, started up, and taken to speed with no issues.

Failure of a rewound generator after six months was reviewed by an O/O rep from a Texas facility. This 500-MVA H2 and water-cooled unit is no spring chicken, entering commercial service in 1977. It experienced a major forced outage a year later, 2000 starts by mid-1994, a rewound rotor in 1998 (main shaft lead “burnt in two”), and

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another rewind in 2009 following low megger readings.

The investigations and troubleshooting began in mid- to late 2023 when changes to on-line insulation resistance were observed, with the first generator-ground alarm in early May. With consistent alarms present and other evidence, the plant prepared to disassemble, troubleshoot, and repair during a fall outage.

In the shop, heavy oil contamination was revealed, along with retaining-ring line cracks, a slot liner patch (from the 2009 rewind), improperly applied turn insulation, and coil cracking. A rewind was performed with its own set of challenges, but the peaking unit was able to run numerous times throughout the following summer (2024). Late in September, the unit tripped on vibration after the insulation resistance monitor alarmed. Unit was again disassembled for troubleshooting the next day and, after site testing, was sent to the shop.

Shorted turns were revealed from RSO tests after the turbine-end retaining ring was removed, along with damage to coils 5&6 on the turbine end, braze joint fracture on bottom of coil 5 (vendor only did NDE on every other brazed joint), and burned-through retaining ring insulation from a fault.

Options at this point included a partial rewind of damaged coils, or obtain a spare rotor from a recently retired sister unit in Louisiana. Plant purchased the spare rotor and returned the unit to service while the original underwent more repairs. Much concern existed around the integrity of all the brazed joints. High current testing and thermography were inconclusive.

Ultimately, the decision was made to rewind the machine with all new joints. Because the first attempt at high-speed balancing identified shorts, blower hubs and retaining rings were again removed and sources located. Final balancing was successful.

Too many core issues (Fig 14) are affecting our industry, according to an EPRI presentation, and they are “ugly and expensive.” Largest contributors to core failures are lamination, insulation, and deterioration, but stator winding short circuits, oversaturation, and poor repair/rewinding workmanship are significant as well, according to some insurance company data presented.

Balance of slides review data from EPRI studies, evidence from visual inspection, knife checks for core tightness, core-bolt torque check, stator core and ELCID testing, step iron testing, core loop high energy test, hot spot infrared thermography, on-line condition monitoring, acoustic monitoring, and leakage flux.

GUG VENDOR PRESENTATIONS

Following are a few highlights from GE Vernova presentations based on CCJ notes

taken during the sessions (slides available through the GEV customer portal).

7A6 Generators: Fleet Performance, Operation, and improvement. The 7A6 generator fleet is second only to the 7FH2 in size. The speaker (in jest, presumably) called the generator the “revenue center” and the turbine the “cost center.” Common fleet issues include:

- Corona bar damage at the end of the bar (older units)
- End winding dusting and greasing (which can be “locked up” with wicking epoxy)
- Stator wedges relaxing with time, which vibrate in their slots and cause higher end winding vibration.

A patented process for shimming stator wedges in place has been developed with a major US O/O. It was first performed in 2016; six years later, 151 out of 156 wedges were “still tight.” It is described as a “semi-permanent solution.” The process should be considered when between 25-80% of the core wedges are loose or when there’s more than 4 ft of loose wedges.

Unearthing Root Causes and Top Technical Insights (RCAs/TILs/ERs) Impacting the Fleet. Although it’s been almost a year since the conference, this round-robin review of the most recent TILs shouldn’t be ignored.

TIL2545 (issued January 23, 2025) recommends replacing fan blades in H53(324) generators with the latest blade configuration at the next scheduled outage for “select units between 2018 and 2021.” This is to accommodate the update in the number and size of radial cooling holes in the stator core.

TIL2119-R1 describes a pole-to-pole connector replacement without pulling out the rotor and removing retaining rings. Affected H2- and air-cooled units typically have 700+ starts and were built after 1996. No alarms/trips occur prior to findings and no forced outages are associated with this upgrade. Root cause is listed as low-cycle fatigue (LCF) during start/stop cycles (primary) and insufficient wetting of the brazing sur-

face (secondary). This solution replaces one which employs a U-shaped connector to move stress away from the brazed area, but does requires rotor removal.

TIL2519 (July 18, 2024) addresses tilt-pad bearing damage and involves replacing existing upper two pads with a narrower pad configuration and applies to generators equipped with four-pad tilted bearings commissioned between 2015 and 2018. A65 units “will see this issue,” but while it is described as a relatively painless change if you are doing other work on the unit, it does require removal of the bearing assembly upper half. Caution: These are not inventory parts; lead times are described as 40+ weeks.

TIL2241-R1 (July 18, 2024) recommends inspecting rotor winding connections for broken lamellas, since there are no forced outages attributed to this issue, or alarms/trips prior to discovery. However, recent unit inspections reveal 4-9 lamellas with indications (out of 10-11 for each end winding). Root causes are listed as LCF and HCF (low- and high-cycle fatigue) and reduced flexibility and stress concentration from the presence of brazed material. Solution is to replace with an upgraded connector.

Topics which surfaced during a roundtable on the GVPI generator fleet included:

- Circuit breakers/disconnects and grounding switches between the generator and GSU (generator starting unit) are experiencing ground faults
- The “Fast Wedge Retightening” system has now been conducted on 12 units (a robot is used to tighten wedges with rotor in place) but no subsequent checks for tightness have occurred yet.
- OEM is in the “early stages of applying AI tools
- An interesting application of 3-D printing is to print a component using a “cheap material” to validate dimensional accuracy before the actual component is made
- Torsional vibration monitoring will be included in the OEM’s Gen Advisor package



15. Machine can resurface two collector rings on-site typically in two shifts while the field is on turning gear, removes around 0.01 in. of metal



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- Aeropac (and TEWAC) main leads are failing and leading to forced outages - three units suffered this event in the first half of 2025.

“Generator Field and Stator Testing - Good and Bad Results, and Making the Bad Good, Again,”

Jamie Clark, AGT Services

This comprehensive primer on all things inspection and testing begins with some words of wisdom: Employ only experienced generator specialists, the dirt tells a story (don't clean it up before the specialist has completed the inspection), speed does not equal quality and will not save you money, and extending inspection intervals is proving detrimental to generator reliability. New units are built with less margin, less mass/MW, and lower cost materials.

Balance of slides reviews most every type of visual, mechanical, and electrical test and inspection procedures for all the important components of a large generator, replete with photos showing typical findings and in some cases solutions (Fig 15). Don't be put off by the number of slides (100+).

“Generator Field Failures,”

Global Energy Services Alliance

You'll likely need to contact the presenters for the details as the slide deck is mostly photos illustrating causes and sources of common failures such as retaining rings, turn insulation migration, ground insulation, turn breaks, coil distortion, thermal sensitivity, radial lead connections, and bearings.

“CPV Valley and Cutsforth: Enhance Technological Advancement with EMI Monitoring Diagnostics,”

Cutsforth

(See coverage under CCUG)

“Event Analysis,”

Douglas Weisz, Hubble/Beckwith Electric Co Inc

Not for the faint of heart, most every slide in this 150+ deck is dense and packed with data, equations, graphs, etc., for analyzing the following events: Phase differential current, Isync trip, neutral overvoltage, inadvertent energizing, volts/Hz over-excitation, GSU trip, phase distance, third harmonic neutral under-voltage, ground differential current, reverse power, negative sequence over-current, and loss of field.

“Generator Acoustic and Vibration Testing and Analysis,”

John Mihalic, EME

Presenter states that loose cores have been identified on over 50% of machines tested acoustically over the past five years, noting that they often are not tested unless there is evidence of an issue. Acoustic testing is a non-invasive method to analyze generator vibration; identify issues, especially stator core looseness; and plan proactive

Thermal Sensitivity Testing

Run the unit in the following order and each step record Vibration, MW, MVARs, Field current, field Voltage, armature current, armature voltage, lube oil temperatures, cold gas temperatures and bearing metal temperatures.

1. Run the unit at a constant 10-30% load and 50-60% field current and stay for 1-2 hours to reach steady state/stabilize.
2. Maintain the field current/excitation constant and increase load to 60-80% and hold for a bit.
3. Maintain the constant load and raise the field current/excitation to 100% and hold for a bit.
4. Maintain the constant load and reduce field current to 60-80% and hold for a bit.

16. Thermal sensitivity test involves the steps shown here while recording vibration, MW, MVARs, Field current, armature current and voltage, lube oil temperatures, cold gas temperatures, and bearing metal temperatures

preventative maintenance. Instruments and setup, procedures, fundamental theory, data analysis, and examples (including abnormal conditions) are explained.

“Thermal Sensitive Generator Rotors: Testing, Causes, and Repairs,”

Roger Kondos, Entrust Solutions Group/TG Advisors

A generator field is deemed “thermally sensitive” when there is a bow in the rotor that changes due to excitation.” Reversible causes include shorted turns, distance block fitting, blocked ventilation, and heat sensitive rotor forging; Irreversible causes are wedge tightness and insulation. Slides offer a testing procedure (Fig 16) and mitigation (essentially limiting load/MVARs output) and repair options. Data, analysis and conclusions from a case study are included.

“Generator Stator Troubleshooting,”

Howard Moudy, National Electric Coil

After formally defining troubleshooting, a disciplined and systematic approach to problem solving, and it's purpose, including collecting and analyzing data and identifying and prioritizing contributors to the problem, slides present three case studies with different generator models—suspicion of moisture contamination, T6 neutral ring failure, and ground fault T2-T5. A few of the case study key points worth noting:

- Access to a high-voltage laboratory can be critical to success
- Sometimes commercial priorities take precedence over best technical practice, such as a repair process that costs half of what a rewind would.
- Sometimes a recommended test is not practical from the user's perspective

“Thermal Testing Generator Rotors,”

Keith Collins, MD&A

Slides review aspects of operational speed testing, such as overspeed or at-speed proof test, balance, running IR (insulation resistance while spinning), flux probe (for shorted turn detection), thermal test (or

heat run) for vibration stability at speed, and explores thermal sensitivity and potential causes. Case studies before and after repair data round out the deck.

“Novel Findings in Synchronous Machine Modeling,”

Wayne Cassidy and Dan Leonard, Peregrine Engineering Consulting

Who wouldn't want to view a slide deck that begins “When are power plant people popular at cocktail parties? After the black-out.” This presentation is really for the folks who deal with the grid after the powerplants deliver their electricity. Essentially it reviews, compares, and contrasts three simulation models for round-rotor machines - GENROU, GENTPJ, and GENQEC - with the intention of establishing that GENROU be clearly allowed in future round-rotor model database submittals to grid authorities.

“Generator Uprate Risk Assessment,”

Jacques Leger, E-M/WEG Group

Typical main design constraint for a generator undergoing an uprate beyond its nameplate rating is stator winding temperature and rotor winding temperature. Other factors which must be assessed are airflow, bearing load/temperature, shaft stress/fatigue life, foundation loading, retaining ring material, and excitation to the field - all reviewed here in detail. A case study for a 2-pole generator uprate and voltage change is presented.

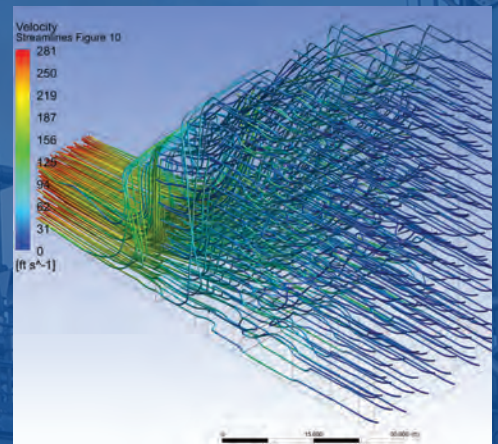


Centralized relay data management (DMA) was the topic presented by a specialist from a Florida utility along with engineers from Schweitzer Engineering Laboratories Inc. Objectives were cybersecurity-, physical-security-, and operations improvements.



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End results reported are managed and monitored Intelligent electronic device (IED) passwords, active device setting monitoring, and improved time from an IED event to diagnosis and recovery. Slides cover basic architecture, one feature of which is inserting Schweitzer's "Blueframe" device between relays in the plant and the DMA box.

"Turbine Controls Reliability Assessment a.k.a. Health Check,"

Abel Rochwarger (and others), AP4 Group

Slides go beyond "typical" reliability assessment (RA) activities (inspect, clean turbine control panel, check voltages and other parameters, resolve alarms, and inspect junction boxes) to more value-add ones like addressing unstable GT exhaust temperature, calibrating valve stroke position feedback, investigating battery failure, and resolving start permissives associated with the inlet filter house.

"Calibration Program,"

(See summary under CCUG)

"ABB AlarmInsight™,"

Tom Maczuzak, ABB

Speaker asks the question, "how do you ensure the alarm system is effective?" Then he answers it, first reviewing what causes ineffective alarming and official technical documents (EEMUA191, ISA-18.2, and IEC 62682 1.0) for rationalizing alarm systems, then presenting company's lifecycle alarm management system (AMS) concept. Important note: It is easy to get to 80% alarm rationalization; the last 20% is difficult. Key step is making sure the AMS is properly integrated into the DCS.

"Consistent and Optimal Combined Cycle Operations,"

James Nyenhuis, Emerson

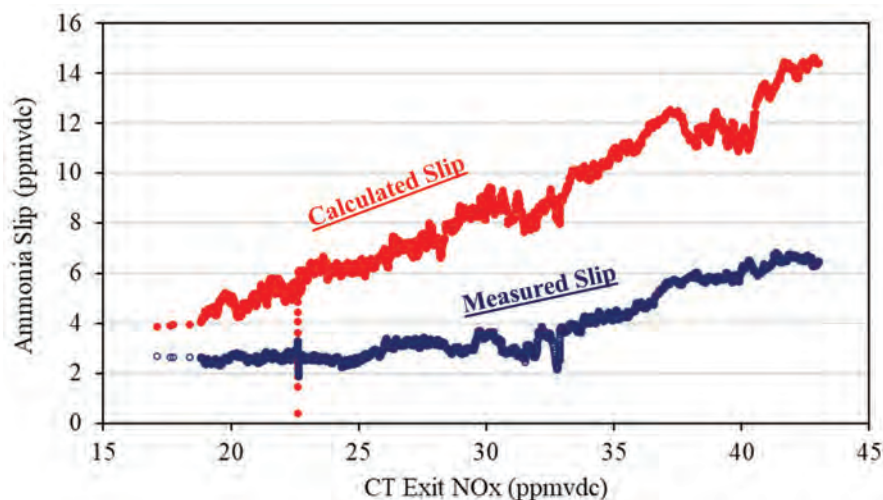
(See summary under CCUG)

"Exposed Alarm Management,"

Benjamin Poskie, Emerson

The gap between "where [the industry] has been versus where [the industry] needs to be" vis a vis control room displays results from an overall lack of understanding of what to do and how to do it, non-existent or non-specific standards, disorganized graphics, excessive alarms, and workspaces which do not support human ergonomics or cognitive conditions.

This slide deck focuses on the alarm management piece. First step is analysis of the current situation, a baseline alarm report with performance scores in critical areas such as alarms per hour, chattering, top flood events, etc. Next is to apply software tools, including (in Ovation) an alarm health advisor and AgileOps. Example: Instead of allowing operators to retain alarms while in outage as reminders for startup checklists, create a separate startup checklist graphic. Tips for alarm suppression are also included.



17. Calculated vs measured slip may not match because of incorrect NO₂/NO_x ratio, poor ammonia flow calibration, GT exit NO_x not known, stratification in the stack, and/or ammonia oxidation

ed.

"Enhancing LM6000 Engine Performance Through Data-Driven Solutions: A Snapshot of Success,"

Maxwell Erwin and Kellan McCarthy, SISO Engineering

Proprietary software-as-a-solution (SaaS) automation and analytics platform (trade name "Snapshot") is presented through an aero-engine case study, addressing (1) power output constraints caused by the max fuel limiter activating when it shouldn't, (2) N44 speed probe failure (which could have led to an unplanned outage), and (3) NO_x water flow tuning. In all three events, troubleshooting was conducted quickly and precisely by leveraging insights from company's remote experts and, in the case of NO_x, quickly building a model and applying it to determine a new target water flow.

"Understanding Isolated Phase Bus Requirements for Transformer Change-outs,"

Mohsen Tarassoly, Electrical Builders Ind

Transformers are critical assets typically with no redundancy and long lead times for replacement. Presenter explains the change-out process (for system uprate, aging components, or failure), the critical path, steps to ensure success, contingency plans, and spare parts. Perhaps most importantly, overlooked areas like inspection of the connecting isolated phase bus are addressed.

Two case studies are included. One involves a change to the LV bushing design spec to accommodate increased power output, a change not communicated to the onsite team. Existing conductor mating surfaces were reconfigured to match the new design and EBI provided replacement copper adapter plates and aluminum connection shunts with expedited fabrication and shipping.

In case study 2, EBI addressed cracks in the conductor flex laminates during installation of three new single-phase GSU transformers. EBI sourced and installed the new conductor flex assemblies without affecting the outage duration.

"What Plant Instruments Can and Cannot Tell You About Your SCR,"

Dan Ott, Environex Inc

Slides begin with listing what data (and instruments) are available from the ammonia skid and why, for example, your calculated ammonia slip may be substantially different from your measured slip (Fig 17). Later slides explain why certain readings are trending in one direction or another, and offer good design practice for transmitters, sample lines, valves, etc. Pay attention to the little things, like keeping the header pressure gage in good working order, repipe and calibrate catalyst dP transmitters, and inspect the SCR regularly.

"Non-optical Flame Detectors,"

Paul Mitchell, GE Vernova

Now "standard on the 7F fleet," non-optical flame detectors (NOFD) are a supplement to existing flame scanners or can replace them. Idea is to monitor individual combustor cans for global flame detection using an algorithm based on exhaust temperature, combustion dynamics, speed, and compressor discharge pressure (CPD). Once the NOFD is operable, the scanners can be ignored or removed, avoiding the associated O&M costs and issues.

New F and H units are now being shipped NOFD-only. There are modifications required, such as a Gen IV CDM (combustion dynamics monitor) and new CPD sensors. Official documents GEK121822 and TILs 2426 and 2433 (issued 2023) provide guidance. [CCJ](#)



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PTZ webinar draws global audience to a persistent steam-turbine problem

More than 500 registrants from 56 countries signed up for the March 31 IAPWS/CCJ webinar on damage and failure in the phase transition zone of steam turbines. That turnout said plenty before the first slide appeared. The subject was narrow by title, but not by consequence. Deposits, pitting, corrosion fatigue, stress-corrosion cracking, steam purity, carryover, and shutdown protection all converge in this part of the low-pressure turbine, and when plants get any of them wrong the result can be cracked blades, damaged discs, forced outages, and expensive inspections that still miss the early warning signs.

Barry Dooley, Structural Integrity Associates, UK, and Bobby Svoboda, Svoboda Consulting, Switzerland, used the session to answer eight recurring questions from users: why the PTZ matters, what it is, what chemistry exists there, why failures occur, whether IAPWS steam-purity guidance addresses the problem, whether the PTZ can shift from one blade row to another, how much shutdown protection matters, and whether CO₂ and organics deserve attention.

Their answer, taken as a whole, was straightforward: the mechanisms are well understood, the warning signs are known, and the industry already has guidance to reduce risk. Plants still get into trouble when they tolerate repeat cycle-chemistry problems or leave the low-pressure turbine unprotected during shutdown. Review the key

research findings below and access the full webinar recording by scanning the nearby QR code.

WHY THIS TOPIC KEEPS COMING BACK

Dooley began with the damage mechanisms most strongly influenced by cycle chemistry. For the PTZ, the leading concerns are corrosion fatigue of blades and discs in the low-pressure section and stress-corrosion cracking of discs in the same region. Deposition and pitting are part of that story, not side issues. In Dooley's experience, pitting is where these failures start.

He showed failure examples from L-1 and L-0 rows, attachment areas, and blade profiles. The message was not subtle. Cracks may present differently, but the initiating condition is the same. Deposits form, shutdown protection is absent or inadequate, oxygenated moisture develops on the surface, pits form, and those pits can transition to microcracks and then to full damage mechanisms under operating stress.

One of the most useful reminders in the presentation concerned changing operating mode. The PTZ is not fixed to one blade row forever. On a CCGT unit, for example, a shift from 2 × 1 operation to 1 × 1 can move the turbine expansion line on the Mollier diagram and shift the phase transition zone from the L-1 row to the L-0 row. If a plant changes operating configuration and assumes the old chemistry risk map still applies, it can be

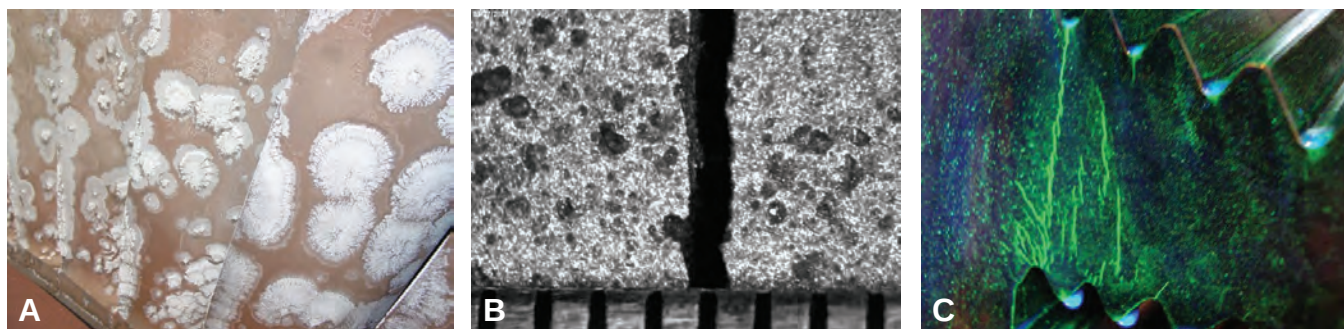
surprised by damage in a different location.

WHAT THE PTZ REALLY IS

The phase transition zone is the location in the turbine where expanding steam crosses the saturation line and moisture first nucleates. In the webinar, Dooley described steam entering the low-pressure turbine superheated and leaving for the condenser with roughly 11% to 12% moisture. The PTZ begins where that expansion line crosses into wet conditions.

That sounds simple on paper, but the environment created there is chemically aggressive and mechanically dynamic. Superheated steam carries impurities, oxides, and ions into the low-pressure section. As the steam crosses the saturation line, it forms very small moisture droplets, often called early condensate or first condensate. Some of these droplets impinge on blade and turbine surfaces and form liquid films. Deposits also form on those surfaces through precipitation, evaporation of moisture, impingement of metal oxides, impingement of salt crystals, or adsorption of impurities.

The measured chemistry is what makes the PTZ dangerous. According to Dooley, early-condensate concentration ratios can reach roughly 150 to 200 times the impurity concentration in superheated steam. If steam contains 1 ppb chloride, the first droplets may contain 150 to 200 ppb. Those droplets are typically around 0.1 micron in size. Liquid films on PTZ surfaces can range



1. Examples of chemistry-influenced damage in the steam-turbine phase-transition zone (PTZ): (a) sulfate and chloride deposits accumulate on low-pressure blades as impurities concentrate during condensation; (b) localized corrosion during inadequately protected shutdowns produces pits that serve as crack-initiation sites; and (c) the combined effects of the corrosive environment and operating stresses propagate corrosion-fatigue and stress-corrosion cracks in blade profiles and attachment regions



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up to about 100 to 120 microns in thickness and may carry concentrations another order of magnitude above early condensate. Both droplets and films are characterized by very low oxygen content during operation. The oxygen problem arrives later, during shutdown, when deposits become moist and the environment changes.

HOW DAMAGE DEVELOPS

Dooley compressed a large body of PTZ research into one operating lesson: these failures require a sequence of events. His estimate was that roughly 14 steps are involved in driving corrosion fatigue or stress-corrosion cracking from chemistry conditions in the PTZ.

The sequence starts with impurities entering the steam from volatility, partitioning, carryover, or attemperation. Once the PTZ forms, droplets and films concentrate those impurities on blade and disc surfaces. Deposits accumulate. During shutdown, if the turbine is not protected with dehumidified air or another effective method, those deposits can become moist and oxygenated. That sets up passivity breakdown and pitting.

Dooley distinguished between metastable and stable pits. The former may form and die. The latter survive and grow. Repetitive non-protected shutdowns are what allow pits to reach critical size. Once large enough, they can nucleate microcracks. If the area also contains an electrolyte film during operation, the microcrack can transition into corrosion fatigue or stress-corrosion cracking.

One reason plants are caught off guard is that the initiation stage can last a long time and be hard to detect. Dooley said many investigations begin with a familiar complaint from the owner: the unit had an NDE exam or inspection only months earlier and nothing alarming was reported. Early pit growth and microcrack initiation can escape routine inspection. A clean report is not proof that the mechanism is absent.

CARRYOVER, DEPOSITS, STEAM PURITY

The presentation then moved from mechanism to control. Carryover was one of the main topics because it governs how much impurity reaches the steam path. Dooley reviewed both mechanical and volatile carryover and tied them to existing IAPWS guidance. Mechanical carryover is evaluated as the ratio of sodium in steam to sodium in boiler water. If that number is high for the unit's pressure, more impurities are entering the steam than expected and the drum internals or operation may need attention.

He stressed that carryover should be checked every six months. Plants that do not know their carryover are operating with one of the repeat cycle-chemistry situations he repeatedly called out.

The volatile side of the issue also has practical consequences. At higher pres-

sures, some species partition into steam more readily than operators once believed. Dooley noted that chloride and sulfate transport is better explained by hydrochloric and sulfuric acids than by older assumptions centered on ammonium or sodium salts. That matters because it changes how plants think about what really enters the turbine.

Dooley also made a point that often gets lost in chemistry discussions: even units with the best steam chemistry can still get salt-crystal deposition in PTZ-relevant areas. Good chemistry minimizes risk; it does not suspend the laws of solubility or eliminate the need for shutdown protection.

Svoboda picked up that theme by reviewing the IAPWS Steam Purity Technical Guidance Document. The objective is to limit the effects of poor steam chemistry, not pretend contaminants can be driven to absolute zero. He reviewed the main impurity classes, including cation conductivity (now known as CACE) as a general impurity indicator, carbon dioxide, sodium, chloride, sulfate, silica and silicates, sodium hydroxide, metallic oxides, and organic matter.

His comments on deposition location were useful for anyone trying to connect chemistry data to turbine findings. Metallic compounds usually deposit toward the inlet of the high-pressure turbine. Sodium hydroxide can appear from the HP into later sections as either deposits or concentrated liquid films. Chloride, sulfate, silica, and silicate issues extend into the low-pressure turbine. In the PTZ specifically, acids are a primary concern.

Svoboda also reminded listeners that chemistry problems are not limited to corrosion. Deposits can obstruct steam flow enough to reduce output and efficiency substantially. He cited cases where phosphate deposits interfered with turbine valve operation and where sodium chloride contamination from seawater ingress caused severe boiler-tube deposit problems. Silica deposits, meanwhile, alter blade surface profile and erode aerodynamic performance.

CO₂, ORGANICS, CONDITIONING AGENTS

In what was a very lively Q&A session, one attendee asked whether CO₂ and organics are important to PTZ damage. The presenters' answer was nuanced.

Svoboda said carbon dioxide is generally harmless in the steam turbine itself when adequate ammonia alkalization is maintained. The larger CO₂ concern is elsewhere in the cycle, especially in heat exchangers and the condenser. Organics deserve more attention because they can decompose into acidic products. Depending on the treatment chemistry and operating conditions, those products can increase cation conductivity and complicate interpretation of contamination events.

He also discussed conditioning agents and film-forming substances. Amines can

improve alkalization in the PTZ, but decomposition products and masking effects still must be understood. Film-forming products offer the additional possibility of hydrophobic protection. That lines up with Dooley's point that film-forming substances may help by limiting wetting of PTZ surfaces during shutdown, although he was careful to say the available turbine data are not yet sufficient to claim the same level of confidence that exists for dehumidified air.

KEEP LP TURBINE DRY DURING SHUTDOWN

If one line from the webinar deserves to be posted in every chemistry office and outage trailer, it is this: keep the blades and discs dry during shutdown.

Dooley said flatly that PTZ failures initiate at pits and that those pits are associated with inadequate shutdown protection. His preferred control method was dehumidified air. He showed an example of a mobile dehumidification system connected through a steam extraction line and said units that previously experienced damage but later installed dehumidification have not shown comparable pitting in subsequent examinations.

The point is not that chemistry limits no longer matter. They matter a great deal. The point is that chemistry control and shutdown protection work together. A plant can improve steam purity, verify carryover, review instrumentation, tighten contamination response, and still leave a damaging gap if the LP turbine sits wet during layup.

Dooley grouped these recurring deficiencies under the heading of repeat cycle chemistry situations, or RCCS. His list included repeated contamination above action level, contaminant ingress above shutdown limit, continued attemperation during contamination, lack of online instrumentation, no knowledge of carryover from drums, no LP turbine shutdown protection with dehumidified air, high air in-leakage, and failure to challenge status quo operating assumptions. He noted that IAPWS guidance documents address each of these conditions and that additional benchmarking guidance is in development.

PTZ damage is not a niche issue limited to a few plants with poor housekeeping. It is a repeatable failure pathway in conventional and CCGT units worldwide. The industry has spent decades measuring droplets, films, deposits, and failure surfaces. The science is not mysterious. What remains difficult is disciplined execution: know what is entering the steam, know where the PTZ sits now, not where it sat under last year's operating mode, and do not leave the low-pressure turbine wet during shutdown.

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Practical solutions for boiler and HRSG reliability



AThe annual meeting of the Australasian Boilers and HRSG Users Group (ABHUG) was held in Brisbane, Australia, November 25-27 2025. Conference and workshop participants joined from Australia, Austria, Germany, New Zealand, the UK and US.

The core technical content of this 17th annual gathering featured 24 presentations and concurrent exhibition, and was sponsored by HRL, Precision Iceblast Corporation, Swan Analytical Instruments, TLG Engineering, and Utrex. Sessions were chaired by Barry Dooley, Structural Integrity, and Bob Anderson, Competitive Power Resources.

ABHUG is supported by the International Association for the Properties of Water and Steam (IAPWS) and is held in association with the HRSG Forum in the US, the European HRSG Forum and the new America Latina HRSG Forum.

All HRSG Forums are highly interactive events for the presentation of new information and technologies, case studies of plant issues and solutions, and open discussions among plant users, equipment suppliers and international industry consultants. Participants include principal engineers, fresh-faced graduates, trainee and experienced global chemistry experts, plus boiler, control system, turbine, material engineers, operators, and dedicated topic consultants.

One ABHUG feature is inclusion of traditional fossil-fueled power plants (Fig 1) and

issues common to both traditional and combined-cycle installations.

THE OPENING FUNDAMENTALS

Sessions opened with Bob Anderson's *16 years of HRSG thermal transient assessment results* providing statistics from detailed investigations at 76 plants worldwide, to determine the most common causes of thermal transients and the actions to eliminate them, covering equipment from 24 HRSG OEMs, 5 gas turbine OEMs, and 11 steam turbine OEMs.

A few key observations: Most causes of HRSG tube failures identified as early as 2009 remain active, and although the industry knows how to avoid these failures, many plants are not applying this knowledge. Most frequently, the failures are associated with low-cycle thermal fatigue occurring during startup and shutdown. If a failure occurs, noted Anderson, "Owners should remove the failure site for metallurgical analysis and conduct root cause analysis to avoid repeated failures." Only eight percent of plants surveyed had a tube failure root cause program in place in 2025.

For attemperators, annual inspections are needed for heavy cycling units, and only 21 percent of plants routinely inspect this hardware. Eighty-six percent of plants experi-

ence leaking spray water and 93 percent use master control/martyr block valve sequencing logic that encourages leaking. Anderson stressed that "master block/martyr control logic can prevent the leaking."

Other practices that increase the risk of failures showed that 39 percent experience attemperator overspray conditions, 29 percent allow operators to manually control attemperators, only 35 percent effectively drain the high-pressure superheater, and only 41 percent effectively drain the reheater during startup.

International updates were also provided, by Barry Dooley, on the cycle chemistry aspects influencing the availability of fossil and combined cycle/HRSG plants. The statistics from detailed assessments at close to 300 plants worldwide indicate that failure to accurately monitor corrosion products is the primary influence (at 85 to 92 percent of plants), closely followed by inadequate instrumentation (80 percent), challenging the status quo (70 to 80 percent), and deposits in waterwalls and HP evaporators (80 percent).

In a follow-up to the chemistry statistics, discussions provided detailed information on sampling, monitoring, analyzing corrosion products, and protecting the steam turbine phase transition zone from corrosion. Said Dooley, "Here the new IAPWS Decay Map provides the first indicator to validate whether the plant's chemistry is optimized and offers a tool to quantify any benefits from an application of a film-forming substance." Dooley continued, "With the growth of renewable energy forcing conventional and combined-cycle plants into more and more flexible operation, the benefits from understanding and then controlling the factors leading to corrosion product transport will be very significant."

SELECTED CONVENTIONAL PLANT HIGHLIGHTS

One feature of the ABHUG conference is increased coverage of conventional plant experience as it relates to basic plant operation including gas turbine combined cycles. A



1. 1680 MW NRG Gladstone Power Station, Queensland



2. New attemperator material and design at Loy Yang A

number of these plants were discussed including the following:

AGL Loy Yang A. Jason Cruikshank, AGL Australia, discussed the *Installation of P91 replacement attemperators* (Fig 2) at the 2200 MW Loy Yang A Power Station that features four large lignite-fired tower boilers. Loy Yang generates approximately 30 percent of Victoria's power requirements and was commissioned between 1984 and 1988.

Cruikshank covered historical problems and solutions, replacement superheater and reheater attemperator design, material and welding considerations, and installation details.

Each unit has four primary superheater attemperators, four secondary superheater attemperators, and four reheater attemperators. Spray flow cycling had become a major issue, depending on boiler fouling levels (among other issues). Resultant temperature cycling led to significant thermal stresses.

Steinmuller offered AGL a design and materials solution using P91 to deal with high thermal stresses, along with spray water line design changes. Material pressure part welding requirements and post-weld heat treatment were covered in detail.

NRG Gladstone. (See Fig 1) Reuben Smith, with NRG's coal-fired Gladstone Power Station in Queensland, discussed the station's six 280 MW steam turbines first commissioned in 1976. His focus: *Reduction of synchronous vibration in HP/IP turbine assembly through hot straightening and re-machining* (Fig 3).

In early 2010, vibration amplitude measured at the front of one unit revealed an upward series of sharp, permanent step changes. Neither the operating regime nor steam conditions had changed, and attempts to realign and balance the machine proved futile.

Smith covered vibration analysis in all zones. Temperature measurements showed a vertical, top-to-bottom thermal gradient after shutdown. These stresses produced an internal bending moment of the rotor, leading to a permanent bow. Smith explained that "Adding weights to correct a bow will

do nothing to address the vibration response that arises from a bent rotor," and he followed with a detailed review of why.

After new rotors were installed, the original rotors were sent to Germany for re-machining and hot straightening (Fig 4). He covered these processes in detail.

The declared "loss of availability" on Unit 1 was reduced from 140 MW to 0 MW.

Callide B. Gerrie Visser, CS Energy, discussed *Last stage blade cracking* at the Callide B station in Queensland (Fig 5). Callide B features two Hitachi 350 MW steam turbines commissioned in 1998.

The primary mechanism was "non-synchronous vibrations at low load (2 to 200 MW) during startup and shutdown," and this appeared in other CS Energy stations.

Visser reviewed critical crack length recommendations, inspection details and in-

spection intervals, followed by specific flow studies.

His conclusions for Callide B:

- Revise low-load restrictions down from 200 MW to 140 MW, in steps.
- Continue in-situ inspections at 12-month intervals.
- Install continuous cover blades (CCBs), "although this will not prevent ultra-low-load excitation and damage."

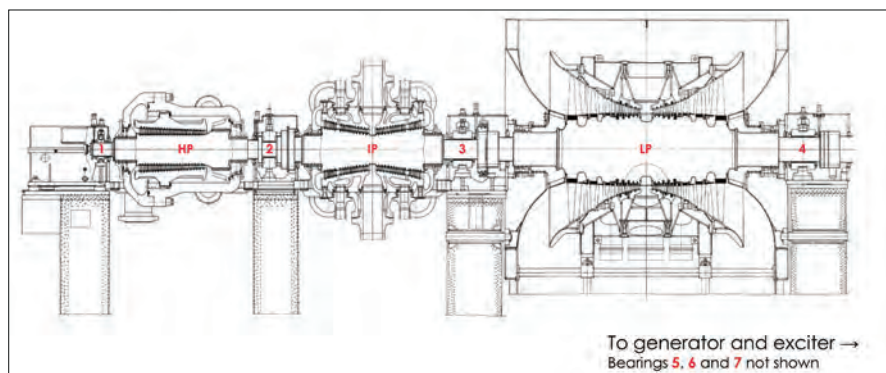
Millmerran. David Ross and Aron Abolis, SRG Global, presented a case story on *HP heater inspection and film-forming substance* at the Millmerran Unit 1 425 MW supercritical coal unit in Queensland, commissioned in 2002. The unit operates at base load with minimal cycling.

In 2022, inspection revealed significant cracking in the feedwater heater. Cracking was visually identified in the feed nozzle to dished head welds. Fracture assessment in 2023 determined the existing defect sizes were marginal and additional operating data was obtained.

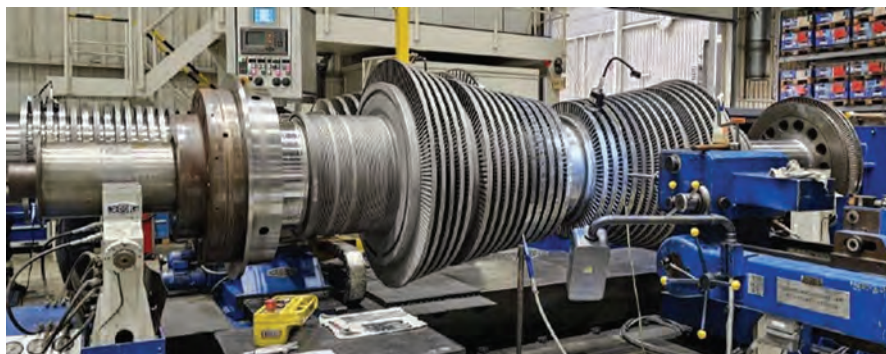
Data analysis continues as are management plans and schedules for replacement.

Bayswater. Matt Harris, AGL Energy, Australia, followed with *AGL's experience with film-forming substance: The ongoing data journey*. His site was the 2640 MW coal-fired Bayswater Power Station in New South Wales.

Vales Point. Vales Point is a 1320 MW coal-fired station in New South Wales commissioned in 1978-79 with two Toshiba 660 MW units. Aron Abolis, SRG Global, discussed a new software product, a Real-Time Damage Monitoring System that accounts



3. 280 MW steam turbine arrangement at Gladstone



4. IP rotor after straightening and re-machining

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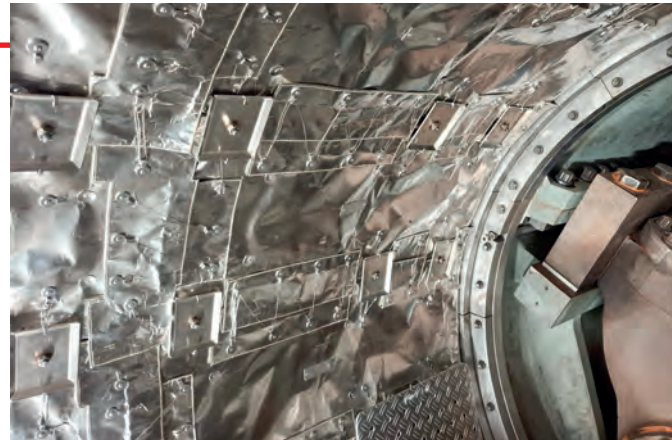


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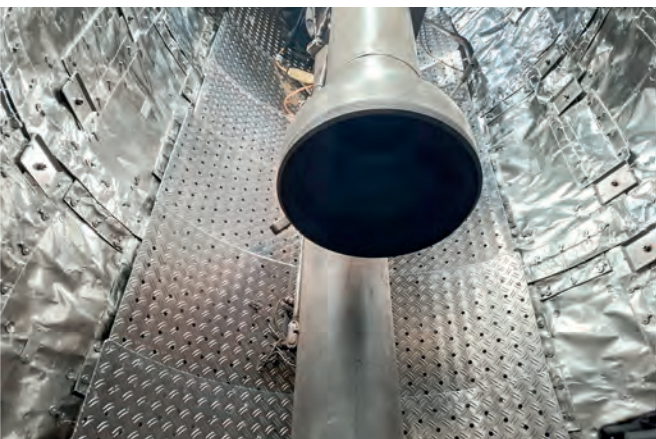
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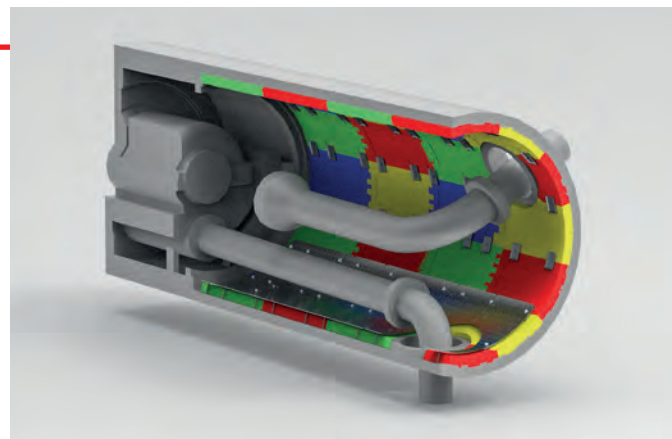
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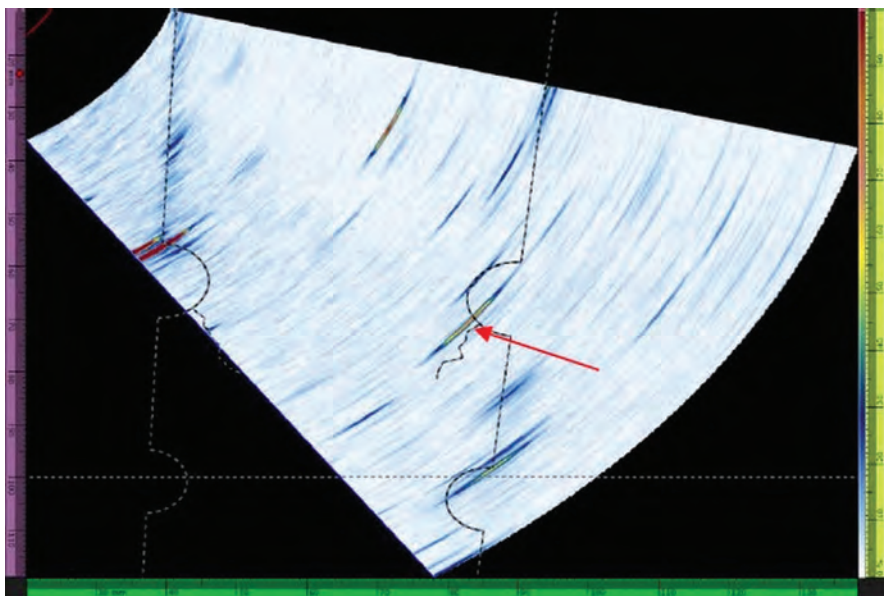
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5. Rotor blade cracks at Callide B

for four different damage types simultaneously: primary creep rupture life, high-cycle damage fatigue, low-cycle damage fatigue, and coupled creep fatigue damage. Examples were discussed in detail.

Torrens Island B. Gordan Gray, AGL Energy, Australia, discussed *A kaleidoscope of boiler activities* at Torrens B. Torrens Island B currently operates three coal-fired Babcock & Wilcox boilers generating 600 MW. Gray covered blowdown system design changes, air preheater rotor issues, and secondary superheater outlet header creep.

Additional conventional plants were noted throughout ABHUG 2025.

OTHER CASE STUDIES AND TECHNOLOGIES

NEWGEN POWER KWINANA

Veronica Yeo gave an update on the New-

Gen Power Kwinana station located at a naval base in Western Australia. The station is a 335 MW combined cycle with 175 MW Alstom gas turbine, 160 MW steam turbine and Alstom HRSG commercial since 2008.

The update covered an economizer outlet lower manifold failure and replacement, duct burner failure and replacement, and HP reheater and economizer tube replacements, among others. Yeo then offered film-forming substance observations using ODA with a 1 ppm target. FFS dosing is directly into the feedwater tank from the top.

For the feedwater tank, water pooling at the bottom showed no signs of offline flash rusting after one week. However, uneven FFS coating was observed.

In the condenser hot well and steam space, hydrophobicity was observed in some areas but uneven coating was observed. HP and LP drum observations showed similar results.

ULTRASONICS

Chris Jones, Quest Integrity, offered *An up-*

date on advanced ultrasonic technology, first taking a deep dive into various aspects and examples of both conventional and newer technologies. His primary emphasis was in-service inspection of pressure parts.

SPRAY WATER LEAKING

Case studies of using clamp-on ultrasonic flow meters (Fig 6) to monitor for early signs of attemperator spray water leaking were also presented. Zelin Agnaev, Emerson Flexim (Germany), offered *Cut maintenance costs; real-time monitoring of attemperator with clamp-on ultrasonic meters*.

Spray water leaking is a leading cause of steam pipework and tube failures in HRSGs. Early leak detection is important so that block valve repairs can be scheduled before serious fatigue damage occurs.

The system presented features low-flow resolution down to 0.01 m/s, has no moving parts, and is a convenient retrofit without opening the pipe.

HP SH/RH DRAIN CONTROL

A case study developed by EPRI, project managed by Competitive Power Resources, and supported by Flexim was reviewed. Anderson's presentation: *Full performance commissioning of automatic HPSH and RH control using ultrasonic technology*.

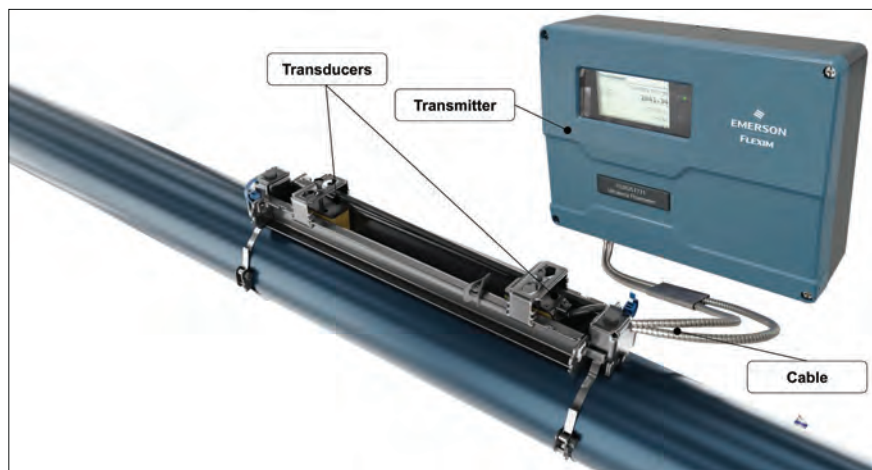
This is the first successful commissioning of an automatic HP superheater/reheater drain control using ultrasonic technology on a new-construction F-class CCGT plant. The system functions by detecting when water versus steam is present in drain pipes, permitting all water to be removed prior to initiating steam flow while minimizing release of live steam.

As Anderson summarized, "This ultrasonic system facilitates draining of condensate during the purge to prevent its accumulation in HPSH/RH modules, expediting the start-up while preventing damaging thermal transients associated with incomplete draining."

ROUNDING IT OUT

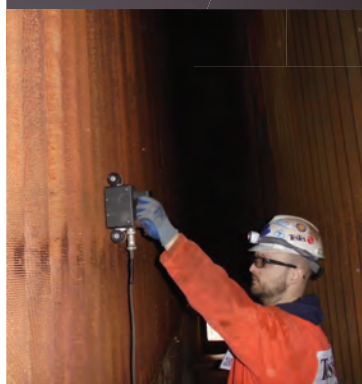
Matthew Smith, Thermic Systems, provided information on a new approach to duct burner design and an optimized SCR ammonia evaporation system. Smith presented the Gemini twin-manifold duct burner, an HRSG Intelligent Recirculation System (IRS), on-load shock-pulse boiler cleaning, and an ammonia vaporization system alternative to electric dilution air heater and hot flue gas fans. The solution presented is the Ammonia Vaporization Optimized Slipstream (AVOS) system using an Induced Flow Heat Exchanger (Fig 7).

David Addison, Thermal Chemistry, New Zealand, discussed key planning requirements for successful execution of HRSG chemical cleaning. In another cleaning presentation, Ryan Esposito, Groome Industrial Service Group, took a deep dive into both



6. Emerson Flexim flow meter main components

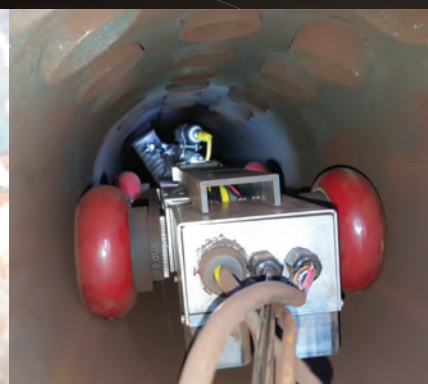
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Finding better ways to inspect them so they stay in running order is ours.



Through Fin Tube
Scanning for Wall Thinning



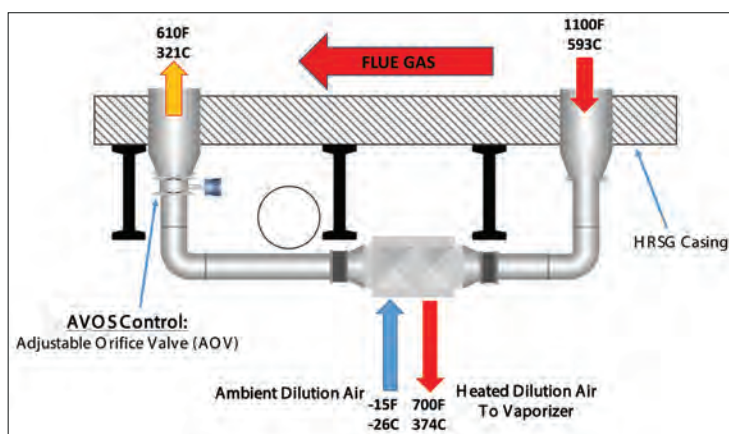
Tube to Header Weld
Examination for Cracking



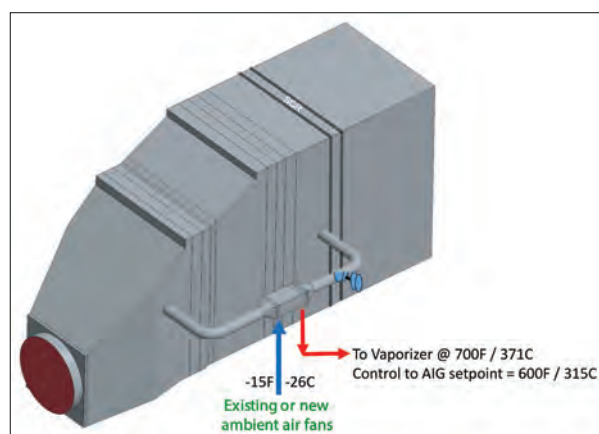
Internal Inspection,
Collecting Tube Video
& Measuring Wall Loss



Better Tools,
Better Inspections,
Better make it Testex



7a. Ammonia vaporization optimized slipstream



7b. Induced flow heat exchanger

finned tube and SCR/CO catalyst cleaning.

Additional presentations covered repair of deaerator and feedwater storage vessels (Steven Bond, Bond Engineering, Australia), stress-induced creep damage from an interference fit (Igor Markic, HRL, Australia), a detailed look at drum level imbalances (Aiman Yusri, HRL, Australia), computer modeling for enhanced reliability and efficiency (Paul Bosauder, Sequence Engineering, New Zealand), large-movement penetration seals with remote monitoring (Jake Waterhouse, Dekomte, UK), and HP econo-

mizer stress corrosion cracking at Diamantina Power Station (Ladislaus Nyakuda, APA Australia). Diamantina is a 242 MW combined cycle facility in Queensland developed by APA Group and AGL Energy.

In addition, Barry Dooley covered *The latest international activities on film-forming substances from seven International FFS Conferences*. Information updates were also provided on the International, Australian and New Zealand Associations for the Properties of Water and Steam (IAPWS, AUSAPWS and NZAPWS).

Supplier presentations were offered by HRL Technology Group, Precision Iceblast Corporation, Swan Analytical, RTR Global, Flotech Controls, Duff & Macintosh, Laser Bond, Freudenberg Flow Technologies, HMA Instrumentation, and Thermic Systems.

2026

ABHUG 2026 is scheduled for November 25-27, 2026, at the Brisbane Convention and Exhibition Center. Information is now available at www.abhug.com. [CCJ](#)

From baseload to dispatch: Reinventing a 30-year-old combined cycle

A great many combined cycle plants were built in the nineties and early 2000s. Not so long ago, many considered them to be reaching their end of life. But the recent power plant construction boom has convinced many asset owners to keep these units running. Some are upgrading them to ensure they last another twenty years.

Take the case of the Sand Lake Energy Center (SLEC) in Orlando, Florida. Built in 1993 and originally a cogeneration plant, its new owner Florida Municipal Power Agency (FMPA) is investing in the facility with the view to achieving another two decades of service.

“We have switched from running 8,000 hours per year to where we will now have fewer hours but more starts,” said Danny Slade, Maintenance Manager, Sand Lake Energy Center. “We are engaged in several improvement projects including gas turbine hot gas path (HGP) upgrades, improved grid connectivity, and perhaps the installation of duct burners.”

OWNERSHIP CHANGES

SLEC began life in 1993 as Orlando Cogen (OCL). The original owner was Air Products, who sited it adjacent to one of its air separation plants. The Air Products facility purchased cold water from a 1,600-ton absorption chiller at OCL that used at least 5% of the plant’s thermal output. In 2001, Air Products sold the plant. It has changed hands several times since. The cogeneration agreement continued until 2024 when FMPA acquired it. At that point, the chillers were decommissioned.



1. Orlando Cogen has been renamed the Sand Lake Energy Center and has transitioned from baseload to dispatch operation

SLEC comprises an ABB 11N1 gas turbine (later Alstom and then GE) configured in a single-shaft arrangement with an ABB VAX steam turbine and a water cooled 144 Brush MVA generator. The combined cycle unit is rated 125 MW at 22°C and 60% relative humidity. Power sales contracts with Florida utilities covered 114.5 MW of baseload output, and deliveries of extra power at peak times as available. The original cogeneration plant supplied 15 t/h of steam at 1.4 bar to an absorption chiller located onsite to chill cooling water for Air Products.

The 11N1 heavy-duty gas turbine was introduced in the early 1990s, specifically designed for high-efficiency, reliable peaking power, and cogeneration applications. It featured a silo combustor, corrosion-resistant blades, and a water-cooled, cold-end generator drive. It uses a single large silo-type combustion chamber located on top of the machine known for fuel flexibility. OCL was one of the first installations in the world of this turbine.

In 2005, OCL upgraded the gas turbine to the Alstom GT11NM, which enhanced power output and reduced CO emissions. It involved new turbine blades and vanes, heat shield segments, vane carrier, and exhaust gas housing. The upgrade improved efficiency and power output by up to 10% without any increase in fuel usage or emissions while reducing lifecycle costs.

Although the GT11N and GT11NM are no longer manufactured, this was a popular machine in its day. By the end of 2005, Alstom reported that the fleet had exceeded one

million Equivalent Operating Hours (EOH) and had an average reliability of 98.9% and availability of 96.0% over a six-year period.

In 2008, Alstom released the NMC version, which consisted of a compressor upgrade and a new rotor. OCL adopted this version. It remains in use to this day at the renamed SLEC. Gas is delivered to the plant from the pipeline at 800 PSI, decompressed to 400 PSIG and heated to 300°F prior to combustion.

WHY SINGLE SHAFT?

OCL was the first application of the ABB 11N1 gas turbine in a single-shaft configuration, which rapidly became the preferred combined cycle configuration. A single-shaft arrangement meant less electrical equipment and a smaller footprint.

“Having one generator instead of two eliminates a major component and associated high voltage electrical auxiliaries,” said Slade. “As well as big capital cost savings when the plant was built, it saves space, improves efficiency, lowers savings and gives extra potential power revenue.”

The ABB HRSG is a dual-pressure unit with finned tube construction throughout. Its design allowed for future installation of an SCR in the event emissions limits were lowered. However, no SCR was ever installed or required.

The original plant control system hardware in 1993 was provided by ABB, a Taylor MOD 300 microprocessor-based distributed control system (DCS). The gas turbine control system was ABB’s Egatrol 300 which communicated directly with the DCS. A full controls upgrade to Alstom BlueLine technology in 2012 included new gas turbine controls, balance of plant (BOP) BlueLine controls in 2014, and steam turbine BlueLine controls in 2017.

The ABB Stal steam turbine (now owned by Siemens Energy) was manufactured in Finnspong Sweden. It is the VAX type, structured with a dual casing with high speed and low speed modules connected via speed reduction gears. It is rated at 40 MW. It has a high-speed, high-pressure (10,062 RPM HP turbine) section connected via a gearbox to a 3,600 RPM low pressure (LP) section. Boiler feed water pumps are each sized for 100% duty and are horizontally split casing design with interstage take off to supply the LP steam turbine. The LP shaft connects to the generator via an SSS clutch.

“Although Orlando Cogen was not the first single shaft combined cycle plant with



2. Danny Slade, maintenance manager at SLEC in front of the electrical room



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an SSS clutch in the USA, it was the first large plant over 100 MW," said Dave Haldeman of SSS Clutch. "Since then, there have been many more installations, some up to 400 MW."

The clutch operates between the exciter end of the generator and the LP section of the steam turbine. It enables the gas turbine to start independently of the steam turbine. It can accommodate large axial movements if necessary. It features high overspeed and overload capacity.

"Air Products specified that a disconnect clutch be included to decouple the steam turbine operation from that of the gas turbine," said Slade. "With the clutch, a steam turbine trip does not necessitate a gas turbine trip,

and the gas turbine can rapidly provide power while the steam turbine is being readied for operation.

MAINTENANCE ACTIONS

As of the end of Q1/25, the SLEC plant had accumulated around 240,000 EOH and more than 600 starts over the course of its 31-year lifespan. Slade was involved in the construction of the facility and has been in charge of maintenance ever since.

"The first real problem was damage to some turbine blades, which were replaced in 1995," he said. "Hot gas path parts are now replaced every three years."

Constant care and attention are needed to keep a plant like this running well. In 2000, there was an HGP casing repair. In 2004, the main 144 kV generator step up (GSU) transformer failed and was replaced with two GE Prolec transformers. The following year, the HP steam turbine rotor had to be replaced and the plant upgraded from the 11N1 gas turbine to the 11NM version.

In 2008, some HRSG inner liner repairs and replacements were done as well as the move to the 11NMC version (compressor upgrade and rotor replacement). The higher air flow from the NMC required GT casing modifications. As part of the upgrade package, new variable inlet guide veins were included as well as aerodynamically enhanced exit guide vanes. These were integrated into

the control software.

The next major event took place in 2011 when a hard engagement of the clutch took place.

"During a plant restart after a scheduled outage, an unusual steam turbine trip subjected the clutch to an unusually high relative acceleration rate at engagement," said Haldeman. "The results were damaged pawls that prevented the relay clutch from



3. Vertical combustor sits above the gas turbine, inlet air in cream on right, and the lube oil system in green in front



4. Alstom BlueLine gas turbine controls



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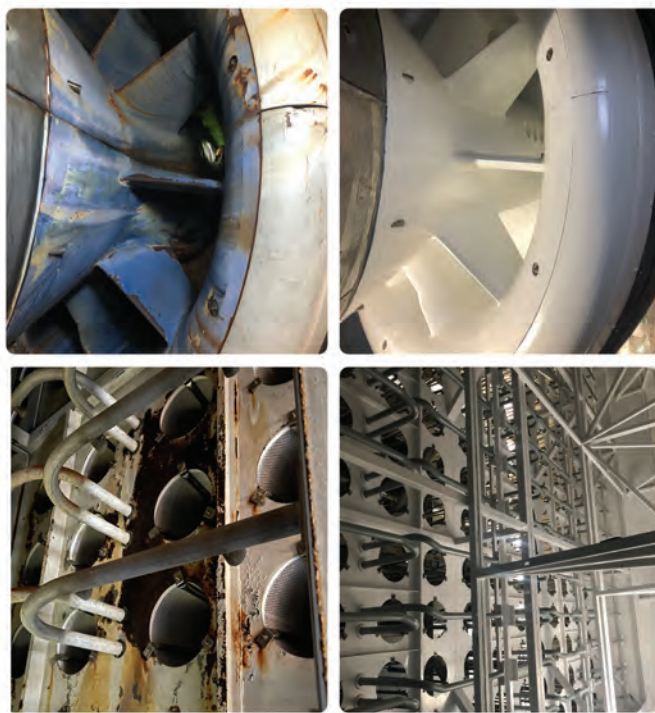
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engaging."

Slade contacted SSS Clutch who flew immediately to the site. Together with OCL crew, they repaired the clutch and got it back into service. Utilizing parts from a relay clutch component, the damaged unit was rebuilt on site. That "temporary" clutch remained in service until 2017. OCL decided to replace it as a precaution.

"That hastily repaired clutch from 2011 ran for six more years before we replaced it," said Slade. "When it was shipped back to SSS Clutch, inspection revealed it to still be working perfectly."

Many use a clutch to switch from power generation mode to providing ancillary services such as spinning reserve or synchronous condensing. This is not the case at SLEC. Its purpose is to enable a faster start up. Without the clutch, it would take 45 minutes or more for the plant to produce power. By disconnecting the steam turbine, the gas turbine can be started independently to provide 10 MW within 20 minutes. The GTs power output steadily ramps up from that point and the steam is gotten to the right heat and pressure to run the steam turbine.

"We can do a hot restart to full power in 45 minutes thanks to the clutch," said Slade. "Otherwise, it would take us about three hours from a cold start to achieve full load."

FMPA TAKES OVER

Florida Municipal Power Agency took over OCL in 2024, signaling the end of the plant's cogen and baseload era. FMPA is a wholesale power agency owned by 33 municipal electric utilities throughout Florida. It operates a pool of generation resources stretching from Chattahoochee and Blountstown on

the Florida panhandle to Homestead to the south of Miami. Its goal is to provide low-cost, reliable power to more than three million Florida residents.

FMPA announced the purchase of OCL and two other central Florida power plants in summer of 2023. The Mulberry Energy Center (formerly Mulberry Cogeneration Facility) will supply 115 MW and the Bartow Energy Center (formerly known as Orange Cogeneration), will supply 104 MW.

"With this acquisition, we had an opportunity to secure three highly functioning Florida-based power plants for our generation fleet at a time when electricity demand began rising faster than expected with continued population growth and manufacturing resurgence," said Jacob Williams, FMPA general manager and CEO.

FMPA took over OCL in 2024, renamed it Sand Lake Energy Center and placed it into its power pool. During most of its life, the facility has been in long-term power purchase contracts, the most recent of which ended in December 2023. FMPA immediately shifted its mode of operation to standby dispatch.

That led to the removal of the chiller system. FMPA then looked at what was needed to ensure reliable operation into the future. It engaged ICT Industrial to replace the aging cooling towers in 2025 with a four-cell cooling tower replaced with a fiber reinforced polymer design. ICT completed one cell initially and then added the other three cells at the end of 2025.

OCL had duct burners as part of its original design. However, the completion of the 11NMC upgrade in 2008 increased mass flow into the compressor by up to 10% which provided the added power previously available from the duct burners. If the facility had tried to turn on the duct burners, it would raise the heat rate from 8,000 Btu to 8,800 Btu, which would have meant burning more fuel and higher emissions.

"We didn't need the duct burners to meet our power contracts so we hadn't used them since 2008 and they were taken out in early 2025," said Slade.

That decision is being reconsidered. Duct burners may be reintroduced to gain more MW for those times the plant is on dispatch



5. The control room at SLEC



6. The HP steam line between the HRSG and the steam turbine

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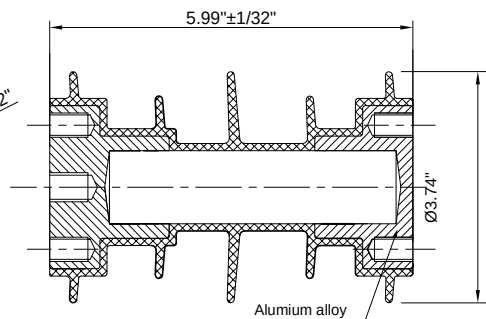
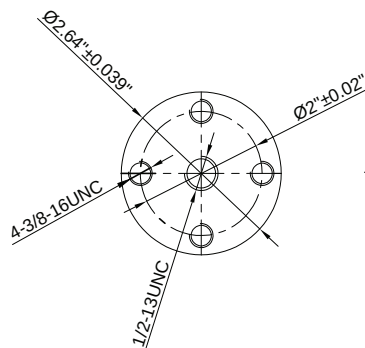
Nominal system voltage.....	13.2kV
BIL rating.....	95kV
Low frequency dry withstand voltage.....	36kV
Low frequency wet withstand voltage.....	26kV
Specified cantilever load.....	2000lbs
Specified tensile load.....	9000 lbs
Compression strength.....	6700 lbs
Torsion strength.....	2900in-lbs
Min creepage distance.....	11.8inch
Acing distance.....	6.14inch
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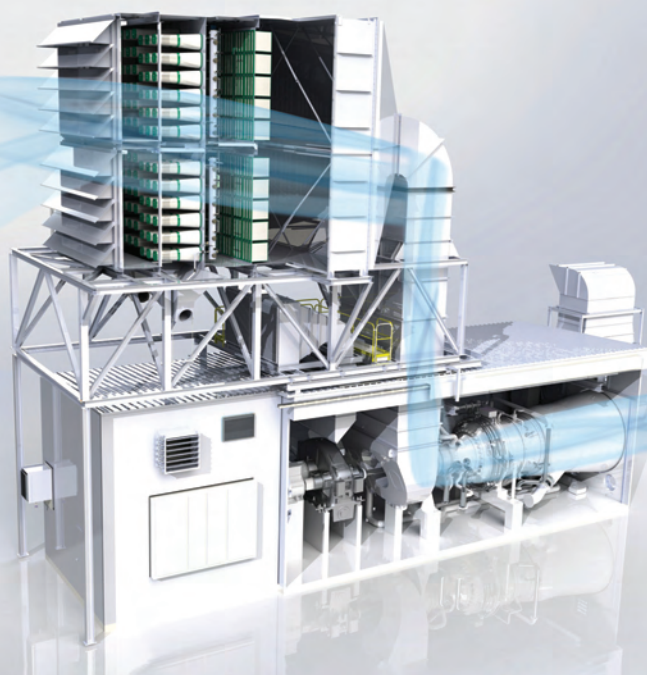
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duty as every MW counts. Slade estimated that new burners could add 4 to 6 MW. If the price of power is high enough, the higher heat rate and extra fuel burned wouldn't be a concern.

GT UPGRADE

FMPA is in the process of upgrading the 11NM gas turbine. The GT11NM XL/XP upgrade takes major inspection intervals from 24,000 to 32,000 EOH in the XL operation mode, improves output by 9.6 MW and efficiency by 2.9%. Alternatively, the XP operation mode keeps the maintenance interval at 24,000 EOH but boosts output by 13.1 MW and efficiency by 3.2%.

This XLXP package entails new hardware on row 4 of the compressor, cooling improvements, and upgraded controls. Hughes Technical Services will be installing the upgrade package during the next major scheduled outage.

"We have switched from running 8,000 hours per year to where we will now have fewer hours but more starts," said Slade. "The XL/XP upgrade and the addition of duct burners will enable us to provide far more MW whenever we are called upon to operate."

Finally, FMPA is considering an electrical improvement. Slade estimated that perhaps 8 to 10 MW of output can be lost due to inef-

ficiency at the transformer, substation, and on transmission lines. The proposal is to upgrade from the current two aging transformers to one larger transformer and restructuring the substation connections to Duke Energy. Such improvements are aimed at having the facility last up to twenty more years.

NEW OPERATING MODE

It is quite a change to go from baseload for thirty years to dispatch only. Slade said that in the first two months of 2026, the facility ran for only six days. This is due to it being part of a much larger power pool. FMPA has many plants to call upon. Prices and demand differ across the network. Those who own the transmission lines take their own cut, too. And plants operate at different efficiencies.

Newer turbines with higher efficiency, for example, may be cheaper to run than an older combined cycle facility like SLEC. Those operating the power pool utilize multiple factors to determine which plants operate and when.

"The FMPA pool has a balancing authority and a great many assets at its disposal," said Slade. "Some might be offline due to an outage, so they utilize all the units in the pool in the most economical way."

LESSONS LEARNED

With more than 30 years at the helm, Slade



7. The SSS Clutch is the cream casing on the left, with a Brush generator on the right



8. A new SSS Clutch was installed in 2017



25 Litre Can
6.6 US Gallons



210 Litre Drum
55.5 US Gallons



1,000 Litre IBC
264 US Gallons



pH
7.2 - 7.5

Specific Gravity
1.01

Corrosion Inhibitor
Yes

Total Alkali Metals After Dilution
< 0.5 ppm



pH
8.0 - 8.5

Specific Gravity
1.00

Corrosion Inhibitor
No

Total Alkali Metals After Dilution
< 4 ppm



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has learned a thing or two about maintenance. Due to ongoing demands for power, he suggested plants consider immediate ways to provide more capacity.

“There is so much demand that you can’t buy a new GT for up to five years, yet there is a growing need for energy,” said Slade. “Upgrade packages and other ways to get more capacity out of your assets have become important.”

Slade also expressed concern about the impact of the shift in operating mode. He isn’t sure how the equipment will react to sudden starts for short periods and then not operating for a few weeks in between. Time will tell, he added, how the economics work out between operating the facility for limited hours versus the cost of starting it up and shutting it down over and over.

He also passed on some suggestions to power plant owners – organize the plant con-

figuration so that maintenance actions can be accomplished easily and speedily. For example, the removal of a rotor a few years ago required dismantling and moving large and heavy components.

“Make sure there is enough room to work on as easy access is key,” said Slade.

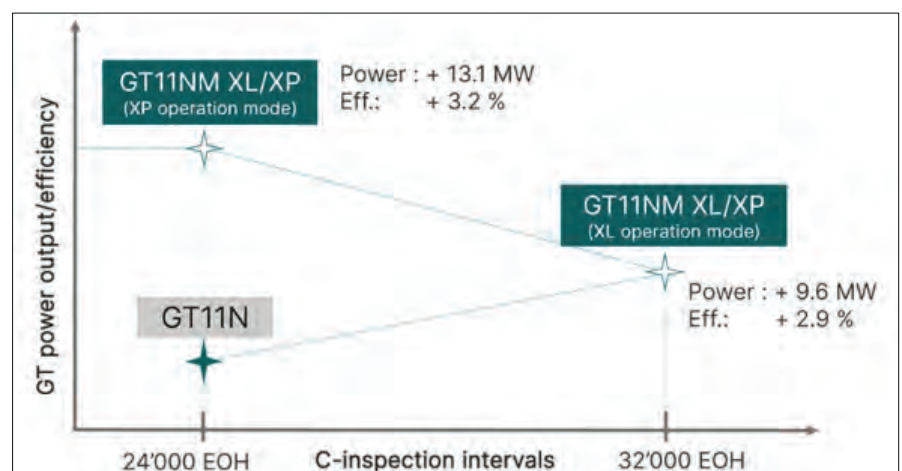
As he is operating a discontinued turbine, finding spare parts is a growing problem. He attends the Alstom Owners Group (AOG) every summer. It is an organization of legacy Alstom equipment owners of GT8,

GT11N, N1, N2, GT13, GT24, and GT26 machines. The AOG collectively shares information and cooperates amongst members to identify and address solutions to common issues, concerns, and shortfalls associated with legacy Alstom equipment.

“We all help each other with obsolete parts and there are some companies that manufacture re-engineered blades and buckets,” said Slade. “But in another ten or 15 years, it is likely to be challenging to find parts for a 50-year-old turbine.” CCJ



9. New cooling towers at SLEC



10. The GT11NM XL/XP upgrade can increase output and efficiency or extend maintenance intervals

EHF2026 keeps focus on recurring HRSG failure modes



The 12th IAPWS European HRSG Forum, EHF2026, met May 19-21 at Monash University in Prato, Italy, with Barry Dooley of Structural Integrity, UK, and Bob Anderson of Competitive Power Resources, USA, serving as co-chairs. The forum remains one of the more concentrated technical exchanges for combined-cycle users, suppliers, consultants, and HRSG specialists because it stays close to the failure mechanisms operators see in the field.

The event was developed and supported by the International Association for the Properties of Water and Steam and held in association with the Australasian Boiler and HRSG Users Group. Mecca Concepts, Australia, organized the meeting, which included 15 sponsors and a program built around 20 presentations, open-floor discussion, and a mini-workshop on attemperators. The agenda covered materials, cycle chemistry, operation, tube failures, controls, valves, inspection, fireside cleaning, layup, SCR retrofits, and balance-of-plant equipment tied to HRSG reliability.

SESSION HIGHLIGHTS

Dooley opened the technical thread with the latest international statistics on HRSG cycle chemistry. The database, developed over more than 20 years from more than 400 HRSGs worldwide, continues to show repeat cycle-chemistry situations that are familiar to many combined-cycle plants. The figures cited at EHF2026 were blunt: 85% of plants have ineffective corrosion-product monitoring programs, 77% have less cycle-chemistry instrumentation than recommended by IAPWS, 80% do not monitor drum carryover, and about 74% are not challenging the status quo. IAPWS plans to incorporate these results into a benchmarking process in 2026 so plants can compare their chemistry and flow-accelerated corrosion programs with peer facilities.

Anderson's update on HRSG thermal transients showed a similar pattern. The international database, collected since 2009, indicates only moderate overall improvement. Most damage remains associated with

attemperators and drains. Only 21% of plants routinely inspect attemperator hardware; 86% experience leaking attemperator spray water; 93% of those plants use block-valve/control-valve sequencing logic that encourages leakage. The same dataset shows attemperator overspray in 39% of superheaters and 17% of reheaters, manual attemperator control at 29% of plants, and effective HPSH/RH draining during startup at only 35% and 41%, respectively.

The Day Two mini-workshop on attemperators was therefore well placed. Oliver Selzer of IMI reviewed attemperator designs and useful field modifications, while Anderson addressed damaging thermal transients associated with attemperator operation. The practical message was direct: steam-temperature control hardware that is poorly designed, poorly maintained, or badly sequenced can crack critical HRSG components and produce unsafe conditions or forced outages. The workshop also gave newer personnel a primer on basic designs and gave experienced users a structured review of where the failure pathways start.

Several presentations dealt with life assessment, inspection, and retrofit work. Quest Integrity, Baker Hughes, addressed life assessment of Alloy P91 used in HRSGs and boilers. TesTex reported on inspection techniques for HRSGs, including methods intended to detect internal or external tube corrosion through external fins and robotic tooling deployed into evaporator or economizer tubes from the upper header. GE Vernova covered HRSG upgrades tied to gas-turbine upgrades, and NEM-Energy addressed SCR retrofits in existing HRSGs.

The program also returned to pressure-part management during startup and layup. Anderson reported on full-performance commissioning of automatic HPSH and reheater control using ultrasonic technology to drain condensate from harps during the pre-start purge. The system is intended to limit drum-pressure loss and blowdown-system damage, reduce the risk of condensate migration and downstream thermal shock during startup, and shorten the delay in getting cooling steam to the

HPSH and reheater.

Chemistry remained a major portion of the program. Azito O&M presented operating feedback and procedural improvements from cycle-chemistry management at Azito CCPP, listed in the agenda as 460 MW plus 253 MW. Aquatech International addressed silica management using new-generation high-flow EDI stacks. Kurita Europe discussed Cetamine application in cyclic operation. Dooley also reported on film-forming substances and the latest IAPWS activities, while the highlight discussion linked under-deposit corrosion, hydrogen damage, corrosion-product transport, and deposition directly to HRSG tube integrity.

CONCERNS AND MITIGATIONS

HRSG tube failures remain the main reliability concern. The EHF2026 discussion again put root-cause assessment ahead of short-term patching. The recommended first step after a tube leak is removal of the failure site for metallurgical laboratory determination of the failure mechanism. One combined-cycle plant general manager described an effective tube-leak reduction program built around management's declaration that every tube-leak event would be followed by RCA.

FAC was identified again as the largest HRSG tube-failure mechanism worldwide. The chemistry discussion separated the controls needed for two-phase and single-phase FAC, with pH affecting two-phase FAC and oxidizing power used to prevent single-phase FAC. The same operating thread addressed under-deposit corrosion, hydrogen damage, and heavy deposits in HP evaporator tubes, with tube removal and comparison against the IAPWS Deposition Map used to judge the severity of deposition.

Attemperators and drains remain high-risk components because their problems often appear as thermal transients rather than obvious equipment failures. The data on leaking spray water, overspray, manual control, and poor HPSH/RH drainage point to work that plants can check directly: hard-

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ware condition, valve sequencing, controls permissives, startup drainage, and operator practice. The workshop made clear that design changes and field modifications can help, but they do not substitute for disciplined inspection and maintenance.

Preservation and layup also received attention because many corrosion events begin while the HRSG is not operating. RINA Tech UK reviewed responsive and responsible preservation methods for different operating modes. The discussion noted a recently demonstrated procedure to electrically heat evaporator modules during wet layup to maintain moderate HP-drum pressure at moderate cost, with reported benefits including faster startup, lower HP-drum fatigue damage on startup, freeze protection, and corrosion protection on water-side and gas-side surfaces.

VENDOR AND OEM CAVEATS

The supplier program was useful, but the takeaways should be applied plant by plant. Bang & Clean presented PressureWave+ DeepCleaning reference cases, and the highlight discussion noted continued interest in ice blasting and pressure-wave cleaning for badly fouled finned tubes. These methods can offer fast return on investment when gas-side pressure drop has reduced

generating capacity, but the case for cleaning still depends on fouling condition, access, outage timing, and the value of recovered output.

SCR, catalyst, expansion joints, silencers, and inspection tools carried similar cautions. NEM-Energy discussed SCR retrofits in existing HRSGs, and Cormetech covered modern SCR catalyst. Dekomte addressed expansion-joint membrane developments and hydrogen readiness, including the implications of draft regulations that could prohibit PTFE use in expansion joints and bellows. Bremco's presentation on HRSG steam vent silencers warned that through-life inspection and maintenance are needed to manage atmospheric corrosion and the safety risk from debris ejected during safety-valve lift events.

European code requirements were another caution for owners planning new combined-cycle projects or major HRSG work. TÜV Rheinland discussed requirements and tests at gas turbines for water-tube boilers under EN 12952-8, while the highlight discussion noted that European legislation, including PED and EN 12952, will impose additional testing and certification requirements for new combined-cycle plants in Europe. These requirements should be considered early enough to avoid late design or commissioning surprises.

ACTIONABLE TAKEAWAYS

For users, the practical list from EHF2026 is familiar but still not broadly executed: benchmark the chemistry program, verify corrosion-product monitoring, check drum-carryover monitoring, inspect attenuator hardware, correct spray-water leakage and valve sequencing, confirm startup drainage, and stop allowing undocumented tube leaks to pass without metallurgical RCA. The data presented at the forum show that many plants still have room for improvement on basic practices.

The next step is to turn the forum statistics into site-specific work orders and management expectations. Plants should compare their chemistry instrumentation with IAPWS guidance, review FAC and deposition risk, audit reducing-agent use where corrosion products are elevated, evaluate layup practices for their operating mode, and review HRSG upgrade or retrofit work against code, catalyst, access, controls, and maintenance constraints. EHF2026 again showed that the same damage mechanisms keep returning. The plants that reduce forced outages will be the ones that treat those mechanisms as routine inspection and operating discipline, not as occasional conference topics. [CCJ](#)

Built megawatts are setting the pace for AI

By Peter Perri III



The AI infrastructure market has stopped paying for promises. It is paying for completed megawatts, turbine positions, energized substations, interconnection rights, and the people who can put all of them together before the next model release. If you own or operate a gas-fired plant, that shift is no longer a side story from Silicon Valley. It is changing who buys power, how projects get financed, and what existing generating assets may be worth.

Here are the market signals worth watching.

Speed has become the product

Anthropic agreed to take the full compute capacity available at SpaceX's Colossus 1 facility near Memphis: More than 300 MW and 220,000-plus NVIDIA GPUs. The noteworthy number was not the ultimate size of Anthropic's other announced commitments. It was the delivery time. Colossus capacity was available within weeks.

Google followed with an agreement to pay SpaceX up to \$30.4 billion for access to about 110,000 GPUs. Full payments reportedly reach \$920 million a month from October 2026 through June 2029. Anthropic's disclosed arrangement runs about \$1.25 billion a month. Together, the two contracts represent roughly \$26 billion in annualized

compute revenue.

The spec position paid. SpaceX and xAI bought turbines, transformers, and chips before conventional project-finance underwriting would have blessed the revenue stream. That looked reckless to a market trained to require contracted offtake before ordering equipment. It now looks like inventory purchased before a shortage.

Plant people understand this better than most. When the critical spare is already in the warehouse, the discussion is different. In this case, the spare was hundreds of megawatts of operating compute. The customers that waited became renters, and the owner of the ready capacity named the price.

Capital is moving down the stack

Coatue Management offers another useful signal. The technology investor launched Next Frontier to acquire land near large power sources and convert it into AI data-center sites. Its first reported major project with Fluidstack is a 430-MW campus in New Lebanon, Ind, financed in part by a \$5.7-billion junk-bond offering.

That is growth capital underwriting dirt, steel, and a substation. It is happening because AI can reduce the scarcity value of some software, but it cannot write code that produces a turbine slot, a 500-kV interconnection, a gas lateral, water rights, or com-

munity consent.

Powered land is no longer just real estate. A permitted site beside firm generation has become an option on future compute demand. Traditional infrastructure funds may still value it as a long-duration asset. Technology investors are looking at the same parcel and seeing venture-style scarcity. If you control a viable site, know which conversation you are having before you price it.

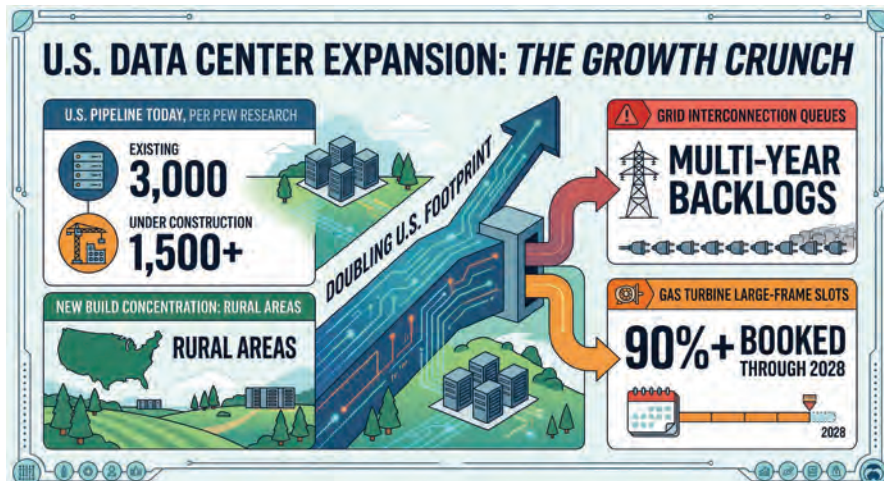
Houston shows the demand-and-price disconnect

CenterPoint told investors it has line of sight to 12.2 GW of firmly committed new load in the Houston area. About 3.5 GW is under construction, and 8 GW is expected to be energized by 2029. The pipeline covers 20 projects and roughly a dozen customers, with 90% of the projects at 500 MW or less. This is not one oversized campus that can quietly disappear. It is a portfolio.

Yet Houston Zone forward prices softened. The conventional model still starts with gas price, heat rate, forecast reserves, and an assumption that high prices eventually suppress demand. AI compute does not behave like a typical price-sensitive industrial load. Hans Royal's Compute Heat Rate framework puts the blended value at roughly \$6,350/MWh, or 127 times a conventional gas-heat-rate benchmark. Frontier inference can tolerate still more.

Meanwhile, the Texas Energy Fund has not produced the expected supply response. More than 70 applications representing over 38 GW were submitted, and 17 projects totaling 9.7 GW advanced to due diligence. By early November, at least eight projects representing about 35% of the selected capacity had withdrawn. Several projects that closed loans were already under development before the program existed.

Watch what developers do, not only what the strip says. Rockland Capital told Texas regulators that forward prices had not kept pace with costs and would not support a final investment decision for its 340-MW New Gulf project. A low forward curve does not build a plant when turbine, EPC, and financing costs say otherwise.



The clock is driving siting and equipment decisions

The xAI dispute near Memphis made power supply a national-security issue. The Department of Justice asked a federal court to dismiss a Clean Air Act suit after the EPA closed the exemption xAI had used for trailer-mounted turbines. DOJ's argument was that Grok supports classified military work and that interrupting its electricity presented a defense risk.

Whatever you think about the politics, the operating lesson is plain. xAI energized 100,000 GPUs in 19 days using a temporary generation bridge. A conventional greenfield plant ordered now may not enter service until about 2032. Heavy-frame order books extend into 2029, combined-cycle schedules run five to seven years, and reported costs moved from about \$2,000 to \$3,000/kW in six months.

Permitting, interconnection, and equipment procurement are now site-selection criteria, not administrative follow-up. Texas demonstrated the point when its large-load queue grew from about 63 GW in December 2024 to more than 200 GW a year later. Capital goes where it believes somebody can reach a decision.

More competition is coming to the turbine market

Hanwha Power Systems and PSM are unifying as Hanwha Power, giving the independent aftermarket supplier access to the manufacturing reach and balance sheet of a major South Korean industrial group.

PSM supports GE 6B, 7E/EA, 7F, 9E, and 9F machines, plus Siemens/MHI 501Fs. Its FlameSheet and LEC III combustion systems have been installed in more than 350 gas turbines across over 30 countries.

Doosan Enerbility is attacking from the new-unit side. It has secured orders for 12 turbines from U.S. buyers, including five 380-MW machines for xAI and seven more for an unnamed U.S. technology company.

For an owner facing an outage or LTSA renewal, this is the practical part: Get more than one qualified party into the conversation. Backlogs and annual price increases have favored the established OEMs. Korean capital entering both the new-build and aftermarket sides gives buyers another source of equipment, technology, and negotiating leverage.

Models are becoming interchangeable inputs. The Palantir and NVIDIA sovereign-AI agreement points in the same direction. Government and critical-infrastructure customers can deploy NVIDIA's open Nemotron models through Palantir's software inside classified or air-gapped environments, tune them on their own operating data, and retain control of the resulting weights.

The model can change. The secure facility, compute hardware, and power supply cannot. For generation investors, that re-

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Product Experience Chart

Customer History

OEM	Fog Systems Installed	Wet Compression
Ansaldo	8	4
GE	802	220
Hitachi	4	1
Kawasaki	4	0
Mitsubishi	50	7
Mitsubishi Aero	106	64
Siemens	148	64
Solar	12	1
Total	1134	361



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duces one important risk: You do not have to pick the winning AI lab to believe the load will grow.

The model companies will change places. The demand for silicon and electrons will remain. Every token still requires kilowatt-hours, and the durable value is collecting around the assets that cannot be copied or energized overnight. That is what is driving the industry right now.

For the deal structures, financing analysis, and market developments behind these signals, read Peter Perri III's PowerSignal, including its subscriber-only editions, by

scanning the nearby QR code.

About the author

Peter Perri is the author of PowerSignal and an energy investor with more than 20 years of experience building and financing power infrastructure. He is deploying approximately 3 GW and scaling toward 10 GW of AI-ready dispatchable generation. No schedule. He writes about deals that matter. Signal, no noise. [ccj](#)



Low load operation and its impacts on Heat Recovery Steam Generators (HRSGs)

PREFACE

The ability to operate combined cycle power plants to efficiently meet a variety of power demands continues to drive change within the power industry. Combustion turbines (CTs) are central to this flexibility, with low load operation providing greater operating range. Heat Recovery Steam Generators (HRSGs) experience the downstream effects of these low load conditions. This article explores the impacts that low load CT operation may have on HRSG units.

BACKGROUND

Low load operation is defined as operating the CT at a reduced output, often 60% capacity or below. Some modern CTs allow for operation at as low as 20% maximum capacity. This flexibility is increasingly important as grid variability grows with renewable sources such as wind and solar. If the CT can be operated at very low loads, it allows the plant to be “parked” at a low output level with relatively few ill effects. Subsequently, the plant can ramp up quickly when needed with lesser fatigue life consumption compared to a start-up. Low load ramp up is quicker than any “fast-start” since the steam turbine is already dispatched and synched.

EFFECTS OF LOW LOAD OPERATION ON THE HRSG

The general effects of low load CT operation on existing HRSG units can be grouped into two main categories as shown in Figure 1 below.

The conditions in Figure 1 are general



Christopher Schroeder and Daniel Michels are Project Engineers on the HRSG Services team at Vogt Power. Both began their careers as Engineers in Training and have gained experience across multiple Vogt Power departments, including Thermal Engineering and Mechanical Engineering. In their current roles, they serve as primary technical points of contact for retrofit projects, including liner replacements and harp replacements.

guidelines rather than definitive outcomes for all low load operation. A combination of lower steam flow rates and higher exhaust gas temperatures can have impacts on fluid operating temperatures, flow rates, and velocities.

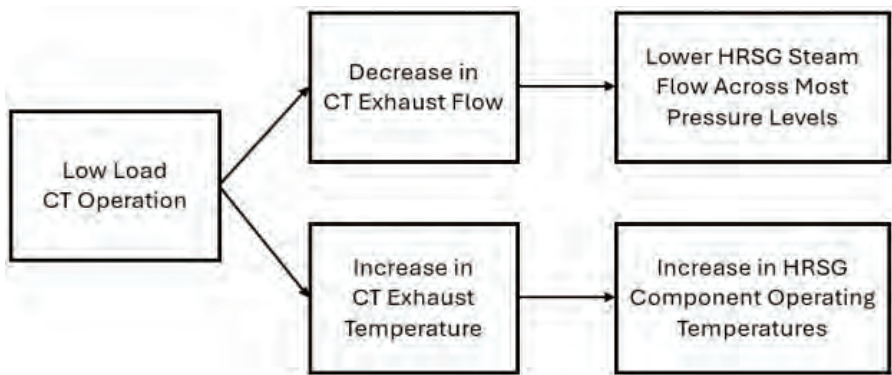
This article is organized in two parts. First, it discusses how low load operation affects HRSG heating surface systems, including Economizers and Superheaters/Reheaters. Second, it examines impacts on other major HRSG components, including attemperators, catalysts, and valves.

ECONOMIZERS

Economizers heat boiler feedwater close

to saturation temperature. This difference between the saturation temperature in the drum and the temperature of the feedwater entering the drum is defined as the approach temperature. The approach temperature is closely monitored to ensure that no steaming occurs within the system. Low load operation may decrease the approach temperature since there is less feedwater flow through the Economizer system. Additionally, a lower operating pressure during low loads also reduces the saturation temperature within the drum. Economizer bypass systems allow the operator to control approach temperatures, but a large increase in required bypass flow to prevent steaming may exceed the maximum allowable flow of the control valve. Without the ability to control temperature effectively, low load operation can cause steaming within the Economizers, which could have detrimental effects.

Low load operation can also affect flow within Economizer sections. At reduced feedwater flow, water velocities through the tubes are lower, allowing buoyancy forces to have a greater influence on flow. As the water approaches saturation temperature, density differences increase. This tends to cause warmer, less dense water to rise. This can oppose the intended flow direction in downward-flowing Economizer tubes caus-



1. A simple flow chart for generalized low load operational impacts on HRSGs.

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ing unstable flow. The velocities through the Economizer should be analyzed to determine if they are high enough to prevent any buoyancy related issue.

Water distribution within the Economizer headers should also be evaluated at low load conditions. At lower feedwater flow rates, the pressure drop available to distribute flow uniformly across the header and into each tube is reduced. As a result, tubes located farther from the inlet connection may receive less flow than other tubes. If this maldistribution becomes significant, affected tubes may be more susceptible to intermittent steaming, elevated metal temperatures, or thermal cycling. Therefore, low load evaluations should consider not only total Economizer flow, but also the ability of the header and tube arrangement to maintain adequate flow distribution.

SUPERHEATERS AND REHEATERS

As depicted in Figure 1, low load operation typically results in higher CT exhaust temperatures and lower steam flow rates. The resulting effects increase the operating temperatures within the HP Superheater and Reheater systems. When incorporating new low load operating conditions, a thermal analysis can be performed to ensure that the Superheater and Reheater systems are operating within the original design conditions. Component re-rates or other mitigation steps can be taken into consideration to ensure component design temperatures are not exceeded.

ATTEMPERATORS

Attemperator systems also require specific consideration during low load operation. Due to the increase in CT exhaust tempera-



2. Attemperator failure resulting from thermal shock

tures and a reduction in steam flow, the required attemperator spray flow at low loads are often substantially higher than baseload operation. Subsequently, the minimum distance requirements for the downstream instrumentation and pipe bends may also need to be higher at low loads due to an increase in spray flow. Ensuring that the spray water is fully atomized by the time the flow reaches temperature measurement devices and pipe bends is crucial for the health and accuracy of the system.

During low load operation, the attemperator spray water temperature and the steam-side pressure commonly decrease. This results in the temperature of the steam flow downstream of the spray point approaching saturation conditions which can result in incomplete vaporization of the spray flow and subsequently quenching. An example of a failure resulting from quenching is shown in Figure 2.

SCR/CO

SCR and CO catalysts are commonly designed to operate at minimum temperatures of 525°F and 600°F respectively. Low load operation results in lower HP steam pres-

sures within the drum that correlates to a lower HP saturation temperature. Since the catalysts are typically located downstream of Evaporator sections in a HRSG, lower HP saturation temperatures during low load operation could result in lower catalyst operating temperatures. This could affect their ability to achieve the stipulated emissions requirements. Verifying catalyst operating temperatures during low load operation is therefore essential.

VALVES

Low load operation can push HRSG-rated equipment beyond required maximum or minimum limits. For example, attemperator control valves may see greater volumetric flow than during normal operation. This increase in flow must remain within valve limits. Similarly, reduced steam production can cause non-return valve flow to fall below minimum design requirements, leading to chattering. This vibration can affect valve integrity as well as surrounding equipment.

CONCLUSION

While some low-load operating conditions are typically considered during the original design, industry demands are requiring combined cycle units to operate at even lower loads for longer periods of time. The maintenance and performance concerns discussed in this article demonstrate the importance of performing a thorough HRSG analysis prior to low-load operation. Such analysis typically starts with a thermal model to establish flow conditions and then evaluates pertinent HRSG components for suitability of operation. HRSGs are durable and flexible assets, but low-load operation should be reviewed carefully so the HRSG avoids any preventable issues in the future.



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How GE Vernova's Houston Learning Center drives plant performance

As the power industry evolves to meet growing demands for reliability, flexibility, and decarbonization, the success of any power plant depends on one constant: the expertise of the people who operate and maintain it. While advanced technology drives the energy transition, it is a skilled workforce that keeps critical assets running safely and efficiently. At the heart of this mission is GE Vernova's Houston Learning Center (HLC)—the company's flagship global training facility. More than a traditional center, the HLC is where OEM expertise, real-world field experience, and immersive hands-on learning converge to prepare both GE Vernova employees and customers for today's dynamic energy landscape.

MODERNIZATION AND CAPABILITY

The facility was recently modernized to expand its training capabilities, featuring upgraded classrooms, advanced digital simulators, and dedicated maintenance laboratories. These bays house full-scale power generation equipment, including a 7HA.03 gas turbine. This environment allows operators, maintenance technicians, engineers, and plant leaders to move beyond theory, performing inspections, diagnosing faults, and practicing maintenance activities under the guidance of experts. This immersive approach transforms technical concepts into practical skills that can be immediately applied upon returning to the field.

LEARNING FROM THE EXPERTS

The HLC's real strength is its faculty. Instructors are GE Vernova's own technical staff, the same people who install and maintain this equipment in the field, so training

reflects how the equipment performs on site, not just how it's designed to perform.

Equally valuable is the insight brought by our One Field Service organization. Many instructors are veteran Field Service Engineers who have spent decades commissioning, maintaining, and troubleshooting equipment in virtually every operating environment. They share "lessons learned" from thousands of outages, emergency service events, and plant startups—providing insights that cannot be found in manuals alone.

This same rigorous standard is applied to training GE Vernova's own One Field Service team. By using the same equipment, procedures, and OEM standards, we ensure that when our teams arrive at your site, they operate from the same technical playbook as your personnel. This shared foundation strengthens collaboration during outages, inspections, and long-term service agreements.

CHOOSING THE RIGHT TRAINING PATH

Selecting the best training format depends on your equipment configuration, and operational goals:

- **Open Enrollment:** It is a cost-effective way to train individual staff in a structured environment, providing access to simulators and labs that may not be available on-site.
- **Site-Specific Training:** Ideal for organizations with unique plant configurations. By bringing training to your location, we provide a program tailored to your specific needs. While legal restrictions prevent



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hands-on training on live equipment, our trainers use site-specific materials and simulators to provide a highly relevant, customized learning experience.

- **Investing in the Future:** The HLC is committed to constant improvement, with recent updates including revamped Controls training that merges maintenance and troubleshooting and upgraded labs for electrical and excitation systems (such as the EX2100/EX2100E).

Looking ahead, the HLC is launching an On-the-Job Training (OJT) program for the 7HA.03 turbine, featuring "learning on the go" simulations. Additionally, our ongoing collaboration with local technical schools and Career and Technical Education (CTE) programs helps build the pipeline of talent needed to support tomorrow's energy systems.

As power generation becomes increasingly digital and interconnected, developing technical talent is as critical as the technology itself. By combining OEM-developed curriculum with hands-on practice, the Houston Learning Center serves as a strategic investment in the industry's most valuable asset: its people. [ccj](#)



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The invisible cost of capacity: Closing the declaration gap in volatile markets

In the current era of grid transformation, a plant's declared capacity is no longer just a static figure in an offer sheet. It has become a dynamic driver of both margin and risk. For many combined-cycle operators, the daily ritual of capacity declaration, often handled through aging spreadsheets and "rule of thumb" adjustments, is leaking significant revenue. The challenge is that this leakage is largely invisible. While over-declaring capacity results in immediate and obvious calls from the energy desk when a unit fails to reach its setpoint, under-declaring capacity produces no such alarms. The plant simply follows dispatch, and the unrealized margin on those hidden megawatts vanishes into the ether.

The stakes are rising as ISO rules tighten and market volatility increases. In a recent webinar co-presented by Primex and Gabel Associates, "Unlocking Hidden Margin: Smarter Capacity Declarations for Volatile Power Markets," industry experts detailed how the gap between actual capability and declared capacity is becoming more expensive. With PJM implementing more stringent follow-dispatch rules (TRLD) and energy markets showing wider spreads between day-ahead and real-time prices, the margin for error has effectively disappeared.

VALUE OF ACCURACY

The financial impact of declaration error is asymmetric. Stewart Nicholson, president and founder of Primex, notes that under-declaring capacity is both more common and far more costly than over-declaring. To understand why, one must look at how these errors are settled.

When a plant over-declares, it essentially sells megawatts in the day-ahead market that it cannot deliver in real time. It must then "buy back" those megawatts at the real-time LMP. The cost (or gain) is the difference between the Day-Ahead and Real-Time (DART) price. While this can be painful during price spikes, the long-term average DART spread is often near zero. In 2024, the average DART spread in PJM was roughly 47 cents; in 2025, it actually dipped slightly negative at negative 5 cents. While the peaks are volatile, jumping from a max adverse spread of \$507 in 2024 to over \$1400 in 2025, the money in over-declaring that exceeds your cost is largely canceled out by the other side of the equation over a full year.

Under-declaration, however, is a pure opportunity cost. If a plant is capable of 1040 MW but only declares 1030 MW, it loses the

opportunity to sell 10 MW of available capacity. In this example, the value of that lost opportunity 10 MW multiplied by the spark spread, which is the difference between the electricity price and the cost of fuel. Unlike DART spreads, spark spreads are almost always positive for an online, dispatched unit.

Recent data from the PJM Eastern Hub underscores this volatility. Average spark spreads for a typical CCGT increased from roughly \$16/MWh in 2024 to \$22/MWh in 2025. More significantly, the "top 5%" peak spreads, the hours where the most money is made, jumped from \$68 to over \$93. In this environment, a persistent 5-MW under-declaration error can easily translate to \$500,000 in lost annual earnings for a single combined-cycle facility. The error is hidden because the plant follows dispatch perfectly, the energy desk stays quiet, and the lost margin is never quantified.

REGULATORY TIGHTENING

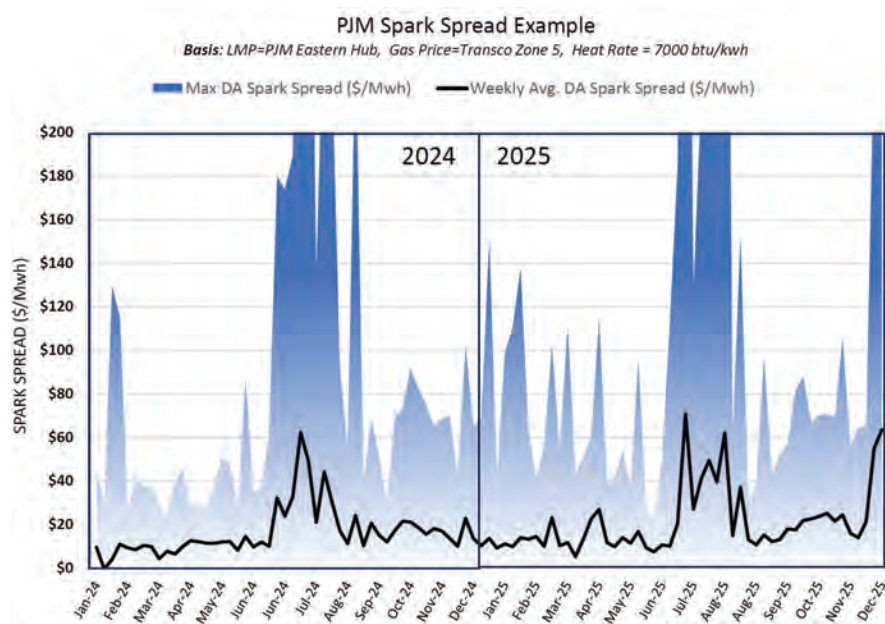
While the financial argument for accuracy is clear, the regulatory argument is becoming equally urgent. Gabby Hudis, Vice President at Gabel Associates, highlighted upcoming changes in PJM that will change how deviations are measured and penalized.

Historically, PJM's rules for "following dispatch" were often viewed as a series of individual snapshots. A unit might be flagged

for a single interval miss, but a persistent, low-level deviation could sometimes fade into the background of the settlement process. This is changing with the introduction of Tracking Ramp Limited Desired (TRLD), a metric scheduled for full implementation in 2027.

TRLD is designed to move away from the snapshot view toward a trend view. It evaluates whether a resource is following the dispatch signal across consecutive intervals. For a plant that persistently fails to follow dispatch, perhaps because it declared a capacity it cannot physically reach, the TRLD approach ensures that the deviation remains visible and the resulting charges (Balancing Operating Reserves, or BOR) accumulate.

This metric replaces multiple older tracking mechanisms with a single, more accurate yardstick. While the de minimis thresholds for deviation stay the same, TRLD makes it much harder for a unit to condense its miss over time without actually getting closer to the dispatch signal. This isn't unique to PJM. MISO and ERCOT have also introduced or refined "sustained deviation" rules. The goal across all RTOs is system reliability. If a unit doesn't move as requested, the operator must rely on more expensive resources to balance the grid. By tightening the yardstick used to measure these misses, ISOs are making it increasingly expensive to



1. Rising PJM spark spread volatility in 2025 magnified the hidden cost of under-declaring capacity, turning missed MWh into lost margin whenever units followed dispatch



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operate with inaccurate declarations.

WHY CONVENTIONAL MODELS FAIL

If the cost of error is so high, why hasn't it been solved? The answer lies in the limitations of traditional plant modeling. Most facilities rely on regression curves, often

embedded in Excel sheets, that use only two variables: ambient temperature and relative humidity.

These models are static. They are typically updated once a season, if that. They fail to account for the complex interplay of factors that affect a combined cycle's true "top of the stack" capability. Wind speed and di-

rection (especially for plants with air-cooled condensers), duct burner performance, cooling water temperatures, and even slight degradation in gas turbine components all shift the actual capability line every hour.

Phil Friedenberg, data science lead at Primex, explains that this complexity is where machine learning provides a distinct advantage. Unlike a spreadsheet, an AI/ML model can process dozens of tags, including generator configurations, facility instrumentation data, inlet air pressure, steam cycle temperatures, and condenser backpressure, to learn how they interact. More importantly, these models self-update daily. If a plant's performance changes due to a tuning adjustment or a component failure, the model sees the new capability in the next day's data.

The system is also resilient to the bad data problem that often plagues automated systems. Friedenberg noted that data utilized for capacity forecasting is put through rigorous filtering. Erroneous points, such as a failed instrumentation signal or a PI point outage, are excluded. In cases of a physical malfunction, the data can be manually removed from the training set, ensuring the model doesn't learn from an outlier event. This allows the model to perform well even in unusual weather conditions, such as the extreme cold events recently seen in the Northeast, as the system quickly learns the plant's true capability even under those specific, rare conditions.

The chart displays three data series over a period from November 20th to 27th. The Y-axis represents 'PLANT NET MW' ranging from 1000 to 1070. The X-axis shows time in 2-hour increments (AM, PM). The 'Primex Declared MW' (green line) and 'Base Capacity Mw' (blue dashed line) are highly correlated, fluctuating between approximately 1045 and 1065 MW. The 'Plant Declared MW' (black line) is consistently lower, fluctuating between approximately 1020 and 1045 MW. A green arrow points to the Primex line with the label 'PRIMEX AI/ML DECLARATION'.

2. AI/ML-based declarations cut total error cost from \$573k to \$247k in this 1100-MW PJM case study, yielding estimated annual savings of \$326,000

80

COMBINED CYCLE JOURNAL, Number 87 (2026)

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A CASE STUDY IN MARGIN RECOVERY

The impact of shifting to advanced data technology is best illustrated through results. In a case study of an 1100-MW PJM facility, switching from conventional regression to an ML-based system fundamentally changed the economics of the plant.

Under the conventional system, the plant experienced roughly 40,000 MWh of declaration error over a single year. This was split between 7,600 MWh of over-declaration and 33,000 MWh of under-declaration. When combined with the heat rate deficit caused by the units not operating at their most efficient baseload points, the total cost of these errors was approximately \$575,000.

The ML-based system reduced this total error cost to roughly \$250,000. While some error remained, primarily driven by weather forecast inaccuracies, which are unavoidable, the more accurate declaration captured an additional \$325,000 in margin.

This isn't just about combined cycles. The technology is already being applied to other asset classes. Friedenbergh mentioned that similar models are now forecasting hydro capacity up to 90 days out, providing better data for maintenance decisions and long-term operating outlooks.

MOVING BEYOND THE

"CORRECTION BIAS"

Overcoming the declaration gap requires a change in operational culture as much as it requires new software. At many plants, an over-declaration is treated as a failure because it results in a call from the energy desk. This creates a natural "correction bias" where operators shave a few megawatts off the forecast to ensure they have a comfortable buffer.

This buffer is the hidden margin. It's the capacity the plant has but cannot predict reliably using conventional methods.

The first step for any asset manager is to quantify the current error. This means looking back at historical data to see how often the plant was "railed" at its declared max while its internal parameters suggested more was available. This validation process, which involves comparing actual production against the previous day's declaration, is the only way to make the invisible visible.

The second step is staying ahead of the regulatory curve. Preparing for 2027 means running a current view of dispatch following performance and BOR charge exposure now.

Finally, for many, the most direct path is a pilot program. Testing an AI/ML declaration system on a single facility for three to six months allows an owner to understand the specific upside for their fleet. As power mar-

kets become more volatile and ISOs become more demanding, the ability to accurately declare what a plant can do is shifting from a back-office administrative task to a front-line competitive advantage. The megawatts are there; the challenge is making sure they all get to market every day. [ccj](#)

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Water-cooled generators: Keep copper oxides where they belong



Water-cooled stator windings have been in commercial service since the early 1960s and remain common on large machines, generally those above about 400 MW. Dr. Robert Svoboda, speaking in the May 26 IAPWS Power Cycle Chemistry webinar on generator cooling-water chemistry, put the installed base at roughly 2000 water-cooled stators outside Russia and China, about 800 in Russia, and more than 1200 in China.

The practical audience questions, from 115 registrants, clustered around layup, startup after outage, conductivity trips, leaks, stainless-steel conductors, and cleaning. Scanning the nearby QR code gives access to the presentation recording.

Water removes heat well, allows high generator outputs in a compact machine, and lowers stator-winding temperature compared with air or hydrogen cooling alone. The exposure is just as direct. When the cooling path is through small hollow conductors in copper stator bars, corrosion products can restrict flow. Loss of cooling can accelerate insulation aging, drive local overheating, or in the worst case melt a stator bar.

Svoboda, an honorary fellow of IAPWS with long field experience in generator chemistry and cleaning, kept the webinar centered on that main failure path: corrosion and plugging of copper hollow conductors. The companion PPChem overview he cited describes this as the most common and severe corrosion-and-deposit problem in generator water cooling. It estimates that 10% to 20% of approximately 2000 water-cooled generators outside Russia and China suffer related flow restrictions sooner or later within the first 25 years of operation.

HOW COPPER PLUGGING DEVELOPS

The plugging mechanism is a four-step sequence: oxidation of the copper surface, release of oxidized copper, migration with the cooling water, and re-deposition where the system can least tolerate it. Copper metal itself does not release meaningful copper into non-oxidizing aqueous media. The oxide layer is the material that dissolves, flakes, travels, and plates out downstream.

Generator deposits typically contain both cuprous oxide, Cu_2O , and cupric oxide, CuO , often with metallic copper mixed

in. The oxygen regime shifts the balance. High-oxygen chemistry tends toward more CuO . Low-oxygen chemistry tends toward more Cu_2O . Svoboda stressed one operating point for low-oxygen units: all oxygen entering the generator is consumed by the coil. Every gram of oxygen ingress can form about 9 grams of Cu_2O or about 5 grams of CuO , independent of the nominal chemistry program.

Copper-oxide release is governed less by a single bulk-water number than by local mass transfer. Flow velocity, turbulence, geometry, temperature, and the solubility of the copper oxide affect how much oxidized copper leaves the surface. pH matters because copper oxide solubility drops as pH rises. That is the basis for alkaline treatment in selected systems.

Design is part of the chemistry problem. Flow geometry, turbulence, and temperature can predispose a unit to release or deposition. Stainless-steel hollow conductors avoid the copper-oxide problem, but most operating units still depend on copper conductors. Mixed-bed and mechanical-filter performance also belong in the first line of defense. Svoboda noted cases where operators shut off side-stream mixed beds and later found plugged generators.

IMPORTANT SPECIFICATIONS

The webinar sorted generator water treatment into low-oxygen neutral, low-oxygen alkaline, high-oxygen neutral, high-oxygen alkaline, and cationic purification. The first four are operating regimes. Cationic purification was presented only for completeness and as a temporary soft-cleaning approach, not a standing chemistry program. Svoboda was blunt in the Q&A: do not use it as normal operation. The utility that developed this method, he said, abandoned the approach after acidic operation produced important wall-loss concerns in hollow conductors.

For high-oxygen chemistry, conductivity at 25°C should be no more than 0.2 $\mu\text{S}/\text{cm}$ for neutral treatment, with troubleshooting beginning above 0.15 $\mu\text{S}/\text{cm}$ and short-term action above 10 $\mu\text{S}/\text{cm}$. Alkaline treatment allows higher conductivity, for example up to 2 $\mu\text{S}/\text{cm}$ with sodium hydroxide. Oxygen should be at least 2000 ppb; below 1000 ppb, the oxide layer can move out of the intended CuO regime and become unstable when high oxygen returns.

For low-oxygen chemistry, the same 0.2 $\mu\text{S}/\text{cm}$ normal conductivity limit applies. Oxygen should be below 20 ppb, with action when it rises more than about 10 ppb above normal.

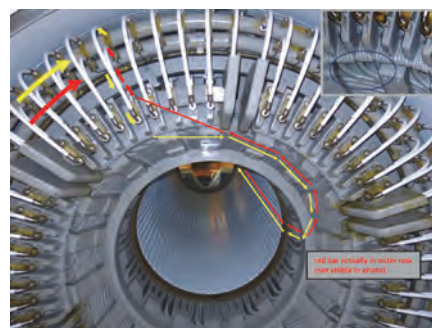
With stainless-steel hollow conductors there are no requirements regarding oxygen in the water. The main specification presented for them was conductivity below 0.3 $\mu\text{S}/\text{cm}$ during operation and, if the stator is left filled or before draining, during shutdown.

Conductivity has two jobs. At low levels it limits pH excursions in high-purity water. At higher levels it limits electric current through the water in insulating hoses. Svoboda cautioned against treating every plant limit as universal. The common 10- $\mu\text{S}/\text{cm}$ upper limit is conservative, while the true limit depends on voltage, water flow, and hose geometry. The operating risk is boiling in the hose, with the possible consequences of loss of cooling, and then arcing if a steam-filled section creates a gas path.

Recommended monitoring was practical: continuous conductivity, continuous oxygen where the regime requires it, periodic copper analysis, and periodic analysis of additives such as sodium in alkaline treatment. Electrochemical potential has promise as an oxide-condition indicator, but Svoboda called the specification tentative because field experience remains limited. He discouraged routine pH measurement in high-purity water because it often produces more false questions than useful answers.

LAYUP CHOICES CARRY CONSEQUENCES

Layup was the strongest operating lesson



1. Stator-bar cooling geometry leaves water trapped after gravity draining; hard air blows are needed before dry layup



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in the webinar. For copper hollow conductors, leaving the system running is the safest short-term layup, provided staff can supervise it and the risk of water leakage into the stator is managed. Shutting the pumps and leaving the system filled is simple and may be acceptable for short periods, but chemistry becomes uncontrolled. Svoboda treated about three days as a practical dividing line, not an absolute rule.

For long-term layup, the recommended path is drain and dry. The process starts by replacing water with nitrogen, valving out the stator from the cooling-water system, and using a series of hard compressed-air blows. Vacuum drying may follow, and pressure should be pulled below the vapor pressure of water at the coldest point. If the coil is dry, it can be left on air. If it cannot be dried fully, return to nitrogen conservation.

Gravity draining is not enough. Fig 1 shows why: the geometry of the stator-bar cooling path can leave water trapped in lower bends. Svoboda put the retained volume in a typical generator at about 500 liters. Vacuum drying after gravity draining will not remove that much water in any reasonable time. The water must be pushed out with hard air blows.

High-oxygen units do not get a free pass on layup. Air entry can lower the pH of the water film through carbon dioxide and upset oxide stability. A unit with an out-of-specification history, including periods of low ox-

xygen, may mobilize oxides rapidly at restart when exposed to air. In practice, shutdown chemistry history is part of startup risk.

FIELD EXAMPLES AND Q&A TAKEAWAYS

The clearest failure example involved a low-oxygen system that was actually running at 100 to 200 ppb oxygen during normal operation. The unit was drained and left idle in air for two weeks. At restart, after no proper layup, oxide flaked from a hollow conductor and redeposited downstream in a bend (Fig 2). The result was a melted stator bar and a shutdown that took months to recover from.

If deposits are already present, the choice is narrow. Mechanical cleaning can include

scraping, blasting, or brushing. Chemical cleaning can use acids or complexants such as EDTA, although Svoboda did not present acid as the preferred route. In the Q&A he said online cleaning with complexants has been performed about 150 times and is a proven method, but it is soft cleaning. Dense plugs may require combined chemical and mechanical work. In some cases replacement is the only practical answer (-3).

Svoboda also separated reactive cleaning from planned maintenance. Some proactive cleanings produced better flows and lower temperatures than expected, meaning the deposits were already affecting performance. He did not support proactive cleaning intervals shorter than 10 years as a general policy. Starting around 10 to 20 years



2. Oxide flaked from a hollow conductor and redeposited downstream in a bend after poor operation and layup

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may be reasonable, depending on condition data and operating history.

On early detection, he pointed operators to flow and pressure drop across the generator, outlet temperature of individual stator-bar hoses, and slot temperatures, with hose outlet temperatures usually more sensitive. He also added a warning that operators should respect: clean indicators do not prove the unit is safe. Oxides can accumulate quietly and then move during a chemistry excursion, poor layup, or restart.

Asked where oxygen ingress comes from in low-oxygen neutral systems, Svoboda named excessive makeup water first. He gave the example of a large hydroelectric plant in which makeup water was intentionally made difficult to obtain, a design discipline meant to prevent casual addition. Other sources include pump seals that suck air into the system and hydrogen leaks into the stator water when the hydrogen is not pure. In one case involving a cracked compensator, he said, a generator plugged within a couple of days.

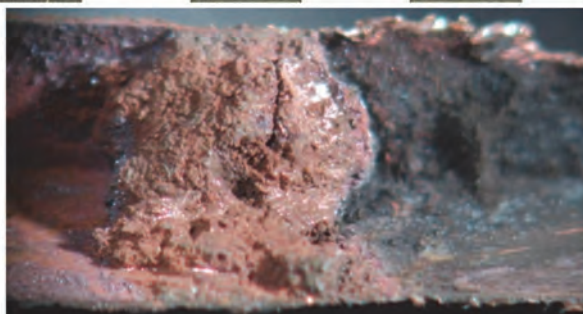
FOLLOW-UP ACTIONS

Treat generator cooling-water chemistry as a stator-bar cooling issue, not as a lab-only specification. Confirm the intended oxygen regime, check whether actual oxygen is living in outside of the transition zone, and know which conductivity limits are chemis-

try controls and which are electrical-current controls. Verify that mixed beds and mechanical filters are operating as designed.

Review layup procedures before the next outage. If the unit has copper hollow conductors and will be down beyond a short interval, gravity draining is not a dry layup.

The procedure needs hard air blows, a dry verification path, and either dry air exposure or nitrogen conservation. Restart risk should include the unit's recent oxygen history, makeup-water additions, leakage history, and any trend in flow, pressure drop, or hose outlet temperatures. [CCJ](#)



3. Dense copper-oxide deposit, including metallic copper, resisted non-invasive cleaning and forced stator-bar replacement

Continuous visibility, fewer surprises with condition monitoring

Cutsforth recently held two technical webinars, one on brush failures and another on generator field monitoring. Taken together, they made a point many plants already know in their bones: generator-side trouble usually does not arrive out of nowhere. More often it builds in the gaps between inspections, in spots that are hard to see, awkward to reach, or easy to dismiss until the damage is no longer small.

The brush discussion stayed close to the collector. The field-monitoring session moved outward into shaft grounding and rotor flux. Different hardware, different language, same underlying problem. Plants are still trying to catch developing trouble before it turns into a forced outage, a ring fire, a bearing event, or a larger generator repair. For more on these topics, scan the QR code to enjoy watching information-dense presentations on demand at www.cutsforth.com.

CONTACT PROBLEMS STILL SIT NEAR THE TOP OF THE LIST

On the brush-rigging side, the most familiar problem was also presented as the most common: restriction in the brush box. Carbon deposits, rough internal surfaces, damaged holders, and bad tolerances all can interfere with brush travel. Because spring pressure is only a few pounds, it does not take much restriction to upset the brush-to-ring connection. Once that connection starts to degrade, arcing is not far behind.

That would be manageable if every problem announced itself clearly and stayed put until the next inspection. It does not work that way. A brush row may be hidden under the collector ring. Lighting may be poor. Access may be cramped. The point made in the webinar was not that plants are inattentive. It was that a disciplined visual inspection program can still miss a problem that develops

quickly or in the wrong location.

Ring condition compounds the trouble. Roughness, ghosting, photographing, discoloration, and streaking can lead to chatter, brush damage, and still more arcing. Once the ring surface is degraded, the machine starts helping the problem along. In the source session, the recommended correction for ghosting and photographing was on-line truing at speed and under load, on the logic that the ring should be corrected in the condition where it actually operates.

GOOD FIELD PRACTICE STILL MATTERS, BUT IT HAS LIMITS

None of this is an argument against traditional brush-rigging practice. Strobe-light inspection, vibration probes, amp checks, and routine walkdowns still belong in the toolbox. Experienced technicians are not being replaced by a screen.

What the webinars argued, more quietly but more convincingly, is that periodic inspection by itself leaves blind spots. Technicians are not there every minute. Measurements can vary by who takes them and how. Some warning signs are not really about a single number anyway. They show up in the duration of an event, the shape of a waveform, or the fact that the same odd behavior keeps appearing at the same point in shaft rotation.

That is where the condition-monitoring case gets stronger. It is not inspection or monitoring. It is inspection plus monitoring, with the latter covering the hours when nobody is standing at the machine and catching the kinds of signatures that do not lend themselves to a quick spot check.

THE HOLDER MATTERS, BUT THE BIGGER ISSUE IS VISIBILITY

Cutsforth used the brush webinar to make a case for an integrated setup: improved

holder design plus wireless monitoring. The holder side of the argument was practical enough. Tight tolerances, smooth internal finish, full-length brush support, and one-at-a-time replacement all aim at the same end, which is fewer opportunities for the brush to hang up and easier maintenance when intervention is needed.

The more consequential part of the presentation was the monitoring layer. Instead of relying on isolated observations, the system described in the webinar tracks brush vibration, temperature, wear behavior, and remaining life by position. The local display gives a technician a whole-rigging view. Historian integration extends that into a broader plant view, where condition data can be folded into maintenance planning.

That changes the conversation. One short brush is a replacement task. A pattern of elevated vibration and temperature across a path of brushes is something else. That begins to look like a ring-surface issue or another broader condition that deserves attention before the unit makes the decision for you.

SHAFT GROUNDING SHOWS WHY WAVEFORM DETAIL MATTERS

The generator field-monitoring webinar made a related argument on a more analytical plane. The central point in the shaft-grounding discussion was not that one grounding method is perfect. It was that plants need to know whether the grounding path is actually doing its job.

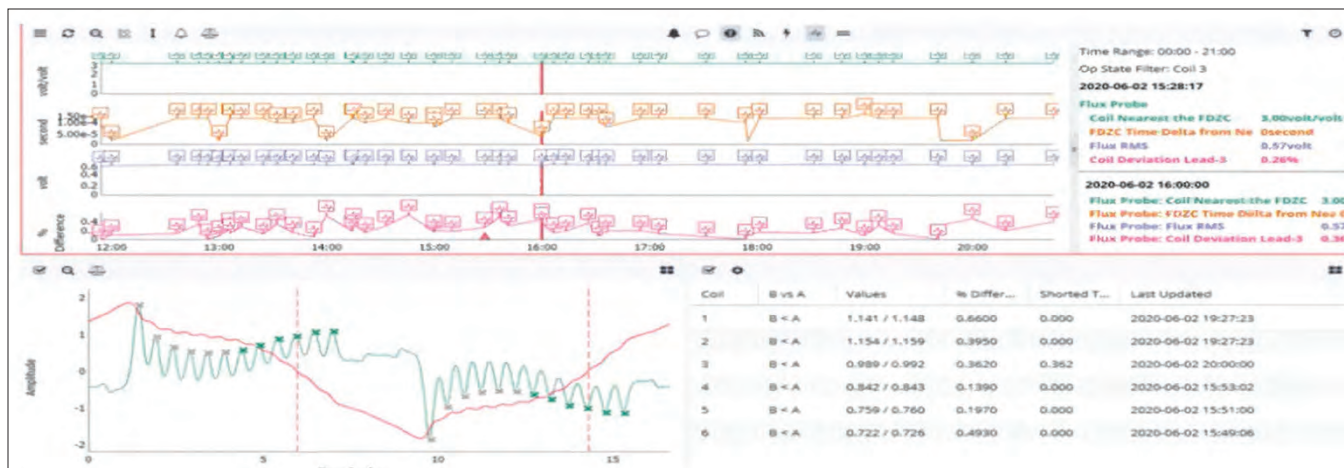
The presenters emphasized waveform behavior over threshold-only thinking. A healthy system is not necessarily the one with the smallest peak. It is the one in which voltage is bled off properly instead of lingering away from zero for a meaningful part of the rotation. That is a more useful way to think about grounding performance, especially across machines that do not all behave the same.

The discussion got more interesting when waveform examples were tied to other machine conditions. One case linked a missing current signature to a bearing problem that disappeared after repair. Another associated dense voltage behavior and load-dependent current features with possible stator-related trouble. In other words, the grounding monitor was not just watching the grounding hardware. It was also showing traces of what the generator itself might be doing.

That is where separate maintenance domains begin to blur. Brushes, shaft ground-



1. Carbon deposits, dirty conditions, holder damage, or poor tolerances can restrict brush travel. With only 3 to 5 lb of spring pressure, even minor binding can compromise brush-to-ring contact, leading to arcing, chatter, and escalating collector-ring damage



2. Rotor flux monitoring provides early visibility into developing rotor winding problems, including shorted turns, before they progress to field grounds or forced outages. Continuous trending helps operators manage cycling-related wear, verify coil health, and support condition-based maintenance decisions

ing, rotor flux, and historian data are often handled as separate concerns. Continuous monitoring starts to stitch them together. When two signals tell the same story, diagnosis gets firmer and response gets faster.

ROTOR FLUX POINTS IN THE SAME DIRECTION

Rotor flux monitoring, as described in the source webinar, follows the same basic philosophy. By tracking coil-pair behavior, zero-cross references, RMS values, and calculated shorted-turn deviations while the unit is online, the system is meant to show whether rotor condition is drifting before that drift becomes a larger event.

That kind of trending matters more in a fleet that cycles harder than it used to. Many units now live with load swings and thermal patterns that were not part of the old base-load expectation. If machine duty changes, monitoring practice has to change with it. A periodic reading may satisfy a procedure. It may not provide much warning.

WHAT IS REALLY CHANGING

The most useful takeaway from the two webinars was not the product pitch, although there was plenty of vendor detail. It was the operating logic beneath it. Collector systems and field circuits are still vulnerable to the same old problems: poor contact, contamination, rough surfaces, hidden degradation, and limited visibility into changing condition. What has changed is the plant's ability to see those problems earlier, compare signals across systems, and turn them into planned work instead of emergency work.

That leaves owner/operators with a fairly plain question. Routine walkdowns and skilled technicians are still necessary. Nobody made a serious case otherwise. But are they enough by themselves for units expected to cycle, recover, and stay available under tighter operating demands? The answer suggested by both presentations was no. Plants still need the human eye and the hu-

man judgment. They also need a better way to know what the machine is doing between inspections.

That may be the real dividing line here. There is a difference between maintaining a generator and actually seeing it. The distance between those two conditions has been wider than many plants would care

to admit. Continuous monitoring does not close that gap completely. It does narrow it, sometimes enough to keep a collector problem from becoming a fire, or an odd grounding signature from turning into a much more expensive lesson. [CJ](#)



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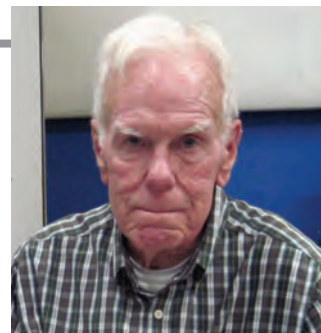
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LEGACY TURBINE FORUM, NO. 8 IN A SERIES

When fuel-gas pressure falls, check transfer logic before buying compression



By Luke Williams, PE, Consultant
www.geLegacyGasTurbineSupport.com

THEME AND SCOPE

More gas-turbine users may soon face the problem that landed on one Northeast plant's desk: available fuel-gas pressure was going down, but the operating obligation was not. The supplier said line pressure would be reduced from 320 psig to 250 psig because of a local natural-gas storage failure. The customer still had to maintain dual-fuel capability under its contract.

The first reaction was predictable. Find a gas compressor and restore pressure to the level assumed in the control specification. But the unit, a dual-fuel GE MS6001B with Mark IV controls, already had fuel-transfer logic designed to move the machine from gas to liquid fuel on a loss of gas pressure. The question became whether that existing system, with revised control settings and proper testing, could solve the immediate problem without adding compression equipment.

ISSUE CLUSTERS

The compressor search did not look promising. Equipment for this application was not readily available, and the cost was high. More important, the proposed compressor was being considered to recover a pressure margin that might not be required for successful transfer if the control logic and fuel system response were understood in detail.

Under the existing logic, a transfer from gas to liquid fuel is initiated when fuel-gas pressure at the gas compartment falls to 265 psig. In a normal transfer, the logic holds for 30 seconds at 0.5 FSR to fill the liquid-fuel piping and check for liquid-system position servo faults. When that timer is complete, gas FSR transfers to liquid FSR at 3.3 FSR/sec. At base load, with FSR at 70, the transfer requires about 21 seconds.

The control specification minimum gas-fuel supply pressure was 270 psig. That value should not be treated as a number floating by itself. It is tied to the amount of gas in the piping downstream of a pressure-loss event, the load on the unit when transfer begins,

the time needed to complete the transfer, and the likely cause of pressure loss, such as a piping leak, upstream valve failure, instrument failure, or curtailment by the supplier. The plant's history of gas-pressure-loss transfers and the consequence of failing to complete a transfer before flame loss also belong in the review.

On a loss-of-gas-pressure transfer, the 30-second fill period is bypassed and transfer starts immediately. As supply pressure falls, the gas ratio valve opens to maintain P2 pressure at the gas control valve. The control algorithm calculates P2 as FPKGNG multiplied by TNH, minus FPKGNO. At 100% TNH, the existing P2 value was 271.6 psig, essentially the current minimum supply pressure. During transfer, the ratio valve may move to 100% position to maintain P2. The gas control valve also continues opening to hold temperature control at base load.

If the gas control valve reaches 100%, load will begin to decrease. The practical question is whether the transfer can finish before flame is lost. Ten seconds into the transfer, fuel mix is roughly 50% gas and 50% liquid. Increasing liquid-fuel flow helps offset the load loss caused by falling gas pressure. At part load in droop control, FSR is fixed by the 4% droop setting. If load starts to decrease and TNH falls, speed control sees the change and increases FSR to maintain TNH. The protection logic allows both ratio and control valves to operate at 100% position because 100% position is not treated as a fault alarm.

CONTRASTING VIEWPOINTS

The conservative answer is to buy compression and restore the supply pressure assumed by the original specification. That answer has merit when the unit cannot tolerate uncertainty, when transfer history is poor, or when testing cannot be performed safely. It also may be the only answer if the lower supply pressure cannot support normal gas operation without driving the ratio valve into saturation.

The other answer is to verify what the machine can actually do. In this case, fuel-nozzle and combustor pressure relationships mattered. Expected pressure ratio across the liner was about 1.05, and fuel-nozzle design had a minimum ratio of 1.15. On a cold day, compressor discharge pressure could reach 170 psig. With the liner ratio, liner pressure would be about 162 psig, and gas-nozzle pressure would need to be about 170 psig to make the required ratio. Those values supported a closer look at revised gas-pressure transfer settings rather than an immediate compressor purchase.

SYNTHESIZED GUIDANCE

The site had never experienced an emergency transfer to liquid fuel. Given the transfer logic, valve behavior, fuel mix during transfer, droop response, and pressure-ratio review, reducing the transfer pressure from 265 psig was judged reasonable. Because supply pressure would drop to 250 psig, the P2 control curve also had to be changed so the ratio valve would not saturate during normal operation. For a P2 pressure below 250 psig, the 100% TNH setpoint constant FPKGNG was set to 0.0452 V/% for a P2 pressure of 240 psig.

The revised transfer pressure was set at 220 psig and tested. The unit completed transfer successfully in the expected 21-second time frame. That result does not make 220 psig a fleet recommendation. It does show that, for this machine and this set of controls, the existing dual-fuel transfer capability provided a workable path around a lower gas-supply pressure.

Users facing curtailment or supplier-driven pressure reductions should not start with the purchase order. Start with the control specification, fuel-transfer sequence, P2 curve, valve limits, expected CPD, nozzle pressure ratio, droop response, and actual site history. Then test the revised setting under controlled conditions. For some legacy dual-fuel machines, the answer may already be in the Mark IV logic. [ccj](#)

Turbine tips: White powder and blueish buckets

By David Such, Such Turbine Consulting LLC



Editor's Note: CCJ welcomes Dave Such as a regular contributor to Turbine Tips. Dave recently retired from Xcel Energy after a 40-year career focused on the operation and maintenance of GE 7F gas turbines. The Combined Cycle Users Group recognized his contributions to the industry with its Individual Achievement Award in 2022, honoring a body of work that spans from commissioning some of the original 7FA units through full life extension.

Dave spent 15 years on the 7F Users Group steering committee and pioneered the use of third-party refurbishment and manufacturing of 7F turbine components at a time when the OEM was the only option. He served as technical lead for gas-turbine flexibility upgrades at Xcel Energy, including installation of DLN 2.6+ with axial fuel staging. He has mentored owner/operators across the industry and never hesitated to share parts, knowledge, and field experience when a colleague was in a bind. This is his first Turbine Tips column. He can be reached at dave@suchturbine.com.

The temperature hovers just above freezing this morning, but with wool socks, my feet are plenty warm inside my steel-toed Redwing boots. The mist of Kroil stings my nostrils, though that is more pleasant than the olfactory assault of a grinding wheel on steel. I can taste it all on my lips. The rattling of

impact wrenches penetrates my earplugs and jars my brain. The bright orange FME covers on the open flanges provide the only contrast to the cold gray metal that surrounds me.

This combustion turbine overhaul is similar to many, but when the fuel nozzles, liners, and flow sleeves come out, they are coated with a mysterious white powder.

Samples of the white powder were sent to the lab and analysis reveals that this substance is sodium sulfate (Na_2SO_4), a corrosive salt. Bingo. My memories flash back. When this mineral gets sucked into the flame, it melts and passes through stage 1 only to condense when the temperature drops in the second stage of the turbine. This molten mineral goo can stick to the airfoils. If turbine buckets are not protected by an MCrAlY coating, the hot corrosion could quickly eat into the base metal and cause a catastrophic failure. Even so, this hot corrosion will eventually eat through the MCrAlY.

When we get the turbine case off, my eyes are immediately drawn to the blueish tint of the stage 2 buckets, and my mind re-winds to an overhaul two decades ago that exhibited a similar condition. The term “hot corrosion” comes to mind, but let’s not jump to conclusions without some help from the chemistry department and a trusted metallurgist. Their assessment confirms my suspicions.

Until they are chemically stripped at the repair shop, we won’t know how compromised these buckets may have been. I suspect they will find patches with deep corrosion grooves on the surface and possibly voids beneath, but as the adage goes:

“One valid test is better than a thousand expert opinions.”

I try to chip off little samples from multiple buckets, but it is very difficult, and I have to be satisfied with a half teaspoon after much effort. The uneven splattering of these condensed minerals on the airfoils may explain why the turbine efficiency decreased in the last several months of operation.

Although the reductionist in me understands that this is sodium sulfate, I must ask: where did this come from? My previous experience leads me up a tall ladder and into the inlet filter house. I crawl through the Hobbit door and continue to the downstream side of the evaporative cooler. As suspected, the knees of my black Carhartt jeans are now white, coated with sodium sulfate. The root cause, I believe, is high mineral content in the water used by the evaporative cooler combined with excessive flow which led to carryover. The high-mineral water carried over to form puddles in the trough downstream of the mist eliminator and other low points, and eventually evaporated, leaving the minerals behind which got

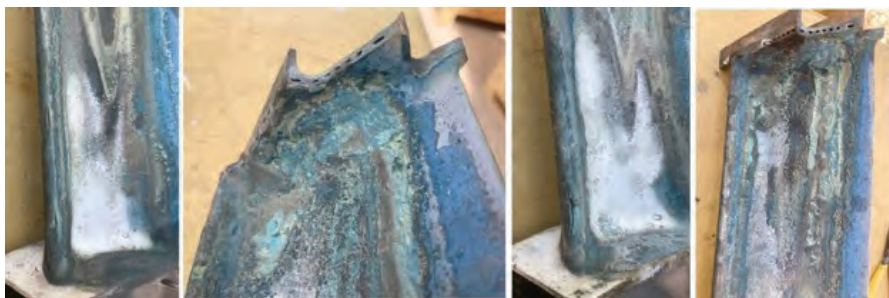


1. White powder discovered on combustion-system components during the outage was identified by laboratory analysis as sodium sulfate, providing the first clue to the source of the turbine’s hot-corrosion problem



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2. Destructive “abstract art” displayed on airfoils. The blue-green discoloration and surface attack on the stage-2 buckets are characteristic of hot-corrosion damage associated with sodium-sulfate deposits

sucked into the compressor and beyond.

Just to be sure, I sample the powder here and compare it to what was adhered to the combustion components. It is basically the same animal: sodium and sulfur.

At this point, the logical questions are these:

- Can we improve the chemistry of the evaporative-cooler water by blowing down the sump when the conductivity reaches a certain level?
- Can we improve the chemistry of the evaporative-cooler water by blending domestic or well water with demineralized water?
- Can we reduce excess water overflow (carryover) from the evaporative media and mist eliminators?

Yes, yes, and yes, but not without effort. The payback will be to preserve turbine efficien-

cy and to reduce refurbishment or fallout replacement costs.

Don't let water with high mineral content (or the powdered minerals it left behind) enter your compressor, combustion system, and turbine. The potential hot corrosion will cost you in the long run, but it can be minimized.

I am an engineer, not a chemist nor a metallurgist, so if anyone with those credentials would like to add anything (or correct me), please chime in by sending me a comment. Here is a good reference article describing the hot corrosion phenomenon:

<https://www.sciencedirect.com/topics/materials-science/hot-corrosion/>

Fun fact: The white powder form of Na_2SO_4 used to be known as Glauber's salt which was used as a laxative from the mid-



3. The trail leads back to the inlet.

Mineral-laden evaporative-cooler water carried downstream, collected in low points, and evaporated—leaving behind the white deposits shown here. Samples closely matched the sodium- and sulfur-containing material found on the combustion components

1600s up until the invention of Ex-Lax Milk of Magnesia and the like in the early 1900s. But please – don't try this at your power plant. [CCJ](#)

Exhaust liner failures: Why small defects turn into forced outages

Ask Scott Schreeg of SVI Bremco what turns a manageable exhaust-liner repair into a forced outage and the answer gets specific fast: a failed stud weld, a loosened sheet, or a hotspot hidden behind the liner system. None looks catastrophic at first glance. But once exhaust flow starts working behind the liner, the problem can move from local damage to a widening mechanical event. For gas-turbine exhaust systems, HRSGs, and simple-cycle stacks, liner reliability is the barrier between hot gas and the outer casing, and between a planned repair and a unit suddenly out of service.

What makes the issue so unforgiving is the way floating liner systems fail. They are built to absorb thermal growth and live with turbulent exhaust flow. When they are intact, that flexibility is an asset. When one part loses support, the same operating conditions that the liner was designed to handle can begin pulling adjacent sections loose.

Schreeg's field message is blunt: defer a small liner repair too long and the scope can grow into casing overheating, insulation loss, downstream contamination, restricted exhaust flow, falling debris, and a much different outage conversation.

MECHANISM

The technical core is straightforward. A floating liner system protects the casing while allowing the exhaust structure to expand and contract through starts, stops, and load changes. It depends on a chain of details holding together at the same time: sound stud attachments, adequate stud density, proper seam stiffening, sheet sizes that can move without distorting, and overlap geometry that keeps flow from catching an exposed edge. If one of those details is wrong, the liner can begin to move in ways the design never intended.

Schreeg points first to stud welding. Attachment quality, he argues, is one of the most important variables in liner life. Poor weld penetration, bad field procedures, and cold welds all show up later as broken support points. Once studs begin failing, liner sheets lose restraint and become more vulnerable to vibration, movement, and distortion under exhaust flow. Retrofit work can be especially tricky because crews are working with existing surfaces, field conditions,

and material variations that complicate installation quality (Fig 1).

Other repeat offenders are design-related. Excessive stud spacing, especially near turbine outlets and diffuser sections where turbulence is high, reduces rigidity and invites liner movement during thermal cycling. Lack of edge stiffening does the same thing at the seams. Batten channels or similar reinforcement methods are often needed to keep edges flat and maintain overlap (Fig 2). Sheet size matters too. Larger sheets carry greater thermal-growth forces and are more likely to distort or buckle in a floating design. Then there is lapping direction. If sheets are installed so the flow sees an exposed edge instead of a protected overlap, exhaust gas can begin lifting the liner during operation. Once flow intrusion starts behind the sheets, failure tends to accelerate rather than stabilize.

OPERATIONAL IMPLICATIONS

That escalation is why Schreeg treats liner distress as more than an isolated met-

al problem. Detached material can move through the gas path and create secondary damage. Insulation can be displaced and migrate downstream. Casing temperatures can climb. In HRSG service, the fallout may extend to duct burners, silencers, pressure parts, and catalyst systems. As insulation and fiber move through the exhaust path, plants can find themselves dealing with emissions-performance concerns at the same time they are trying to control a mechanical repair.

The practical inspection picture is familiar to outage teams: broken studs, missing hardware, displaced insulation, visible fiber debris, distorted sheets, lifted corners, thermal stress near joints and transitions, and areas where hot gas appears to have been running behind the liner (Fig 3). The trouble is that by the time several of those signs are obvious, the job may already have moved well beyond a localized repair. A small corrective scope taken during a planned outage is one thing. A large casing repair or an unplanned outage during a tight operating pe-



1. Exhaust-casing wall prepared for liner repair



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riod is something else entirely.

OPTIONS AND TRADE-OFFS

Once a plant identifies liner trouble, the first decision is whether the problem is truly local or whether it points to a broader design weakness. If the damage is limited, a planned-outage repair may be enough: replace failed studs, restore support, correct a seam condition, reset affected sheets, and recover displaced insulation before more of the system opens up.

That is the low-cost path, but only when the root cause is also local. If the distress is tied to stud spacing, weak edge support, oversized sheets, or bad lapping direction, a repair that addresses symptoms alone may simply buy time until the next failure.

That is where the trade-off sharpens. A broader retrofit or redesign costs more and may expand the outage scope, but it can be the smarter reliability choice in sections exposed to the highest turbulence and temperature swings. Schreeg's point is not that every damaged liner needs wholesale replacement. It is that experienced teams separate one-off damage from recurring design exposure. The deciding information comes from careful outage inspection and, just as important, thermographic scans while the unit is operating.

Thermal patterns tracked over time can reveal developing hotspots behind the liner before internal damage becomes obvious, giving plants a better basis for deciding whether to patch, redesign, or stage a larger repair.

ACTIONS AND LESSONS

The takeaway is refreshingly practical.

Treat liner details as reliability items, not fabrication trivia. Verify stud-welding quality. Review stud spacing in high-turbulence sections. Check that seam stiffening is adequate for the local flow and temperature profile. Make sure sheet size and overlap direction match the service demands of the section. Pair those design checks with disciplined outage inspections and periodic

thermal monitoring under load.

Schreeg's field perspective comes down to timing: the goal is not to get better at repairing liner failures after they open up, but to catch the first broken connection, lifted edge, or emerging hotspot before exhaust flow turns a fixable defect into forced downtime. [CCJ](#)



2. Interior of a 501D rectangular exhaust stack with a floating liner system



3. Damaged exhaust-liner sheets with deformed or detached batten channels

Proactive turbine-oil maintenance moves to the front line of reliability



A turbine end user could once treat lube-oil management as background maintenance. That is no longer a safe assumption. During a recent CCJ webinar offered by C.C. Jensen on proactive turbine-oil maintenance and varnish control, presenter Eddie Rowland, joined by former GE Vernova engineer Tom Freeman and Duke Energy lead engineering technologist Steve Malec, made the case that oil condition now sits much closer to the center of unit reliability.

Their reasons were straightforward: machines run hotter, duty cycles have changed, maintenance intervals are longer, and the consequences of varnish and contamination show up in places operators cannot afford to lose, including servo valves, bearings, gears, and heat exchangers. Continue reading for a full recap and access the webinar recording via the nearby QR code.

Freeman set the tone by tracing how the operating environment has changed. Older machines ran at lower firing temperatures and more predictable duty cycles. Newer fleets do not. He cited firing temperatures moving from about 1900F in early machines into the mid-2000s for F-class units and into the upper 2700F range for newer designs, while oil systems also became more complicated as OEMs combined functions that once were separated. At the same time, cycling has become routine (Fig 1). In Freeman's words, "Get in front of this because you wait too long, you've got more stuff to do than just change oil." That line captured

the webinar's central message better than any slide.

Malec backed that up with an end-user view from Duke's Florida fleet. Some units still start and run for long stretches, he said, but others cycle hard because market conditions and solar penetration keep changing the dispatch profile. One of his stations at one point started and shut down every day. The practical implication is that oil is no longer living in a steady thermal and contamination environment. It is being heated, cooled, agitated, and exposed to different patterns of moisture ingress and system upset than many legacy programs were built around.

Monitoring cannot be casual

Rowland argued that the first mistake is to look for a single condemn-or-keep number. Turbine oil, he reminded the audience, is mostly base stock, roughly 97%, with only about 3% additives. A useful oil report therefore has to cover more than one property at a time: lubricant condition, contamination, additive health, and machine wear signals. He said there is no universal go-or-no-go gauge for when oil must be discarded. Each site has to set its own action limits and, just as important, watch whether the rate of change is accelerating.

That is why sampling discipline got so much attention. Malec described a recurring field problem that will sound familiar to most plant staffs: a particle count suddenly

spikes, looks unrealistic against the trend, and turns out to be a bad sample. On some machines, Duke samples from ports that must be flushed before the bottle is pulled. If that flush step is shortened or skipped, the result can drive the wrong diagnosis. Malec said his group resamples when a result does not fit the trend instead of rushing to a conclusion.

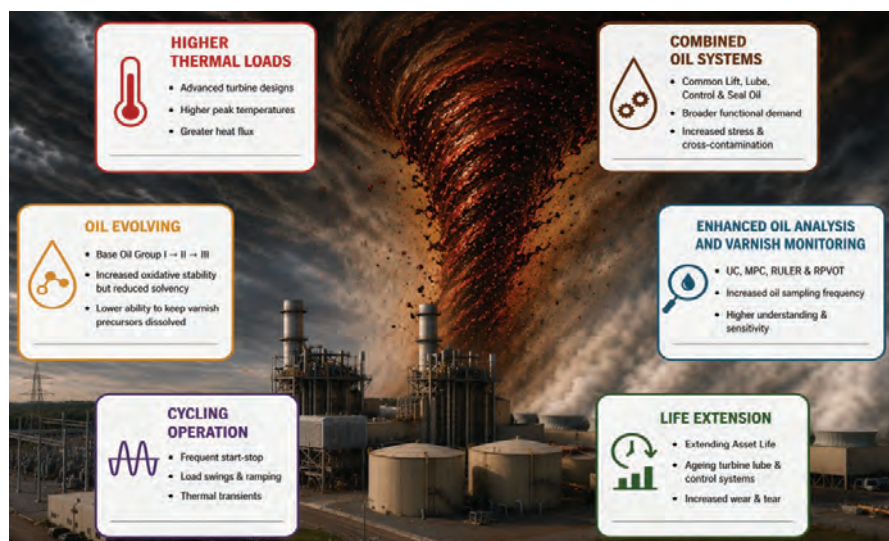
His testing schedule was equally practical. Duke samples quarterly for particles, water, and TAN, does annual RPVOT and RULER work, and runs varnish checks semiannually at his stations. He put the reasoning in plain terms: varnish testing twice a year matters "because that's so critical just to stay on top of it." Rowland then walked through the toolkit behind that program. An ultracentrifuge test ranks insolubles and varnish precursors on a 1-to-8 scale. MPC, or membrane patch colorimetry, ranges from 0 to about 100, with concern rising once the result moves past 20 (Fig 2).

Rowland said the two tests should be used together because plants can encounter "clear varnish," where one indicator may look acceptable while deposit risk is still real. He also cited RPVOT as a measure of oxidation stability, saying a good turbine oil should be above 800 minutes and new oil may run up to about 1200 minutes. RULER testing, he added, is commonly watched for antioxidant depletion, with alarm attention beginning at about 50% of new-oil value.

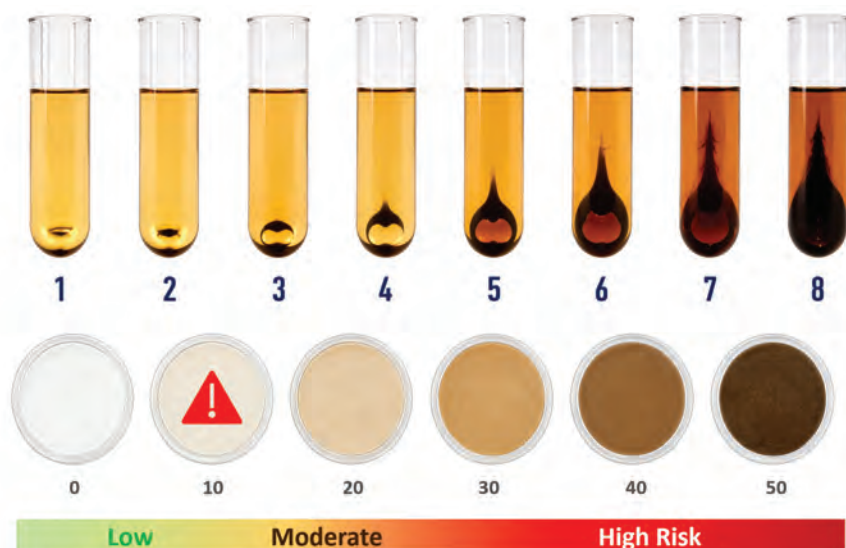
The webinar returned several times to a point that is easy to overlook: it is usually cheaper to keep contamination out than to remove it later. Rowland said plants that do a poor job controlling ingress often wind up fighting particles, water, and varnish after the damage path has already opened. In that respect, oil analysis is not just a lubricant test. It is also a machine-condition and work-process check.

What proactive control looks like

The equipment discussion stayed grounded in mechanism. Rowland said there is no "magic filter" that handles every oil application the same way, then described the company's varnish-removal approach for gas-turbine service. The idea is to cool the oil to about 40F so oxidation byproducts precipitate, agglomerate, and can be captured by adsorption media instead of remaining dissolved in the fluid. He described the arrangement as an off-line loop drawing from the reservoir bottom and returning to



1. Higher thermal loads, combined oil systems, cycling duty, evolving lubricant chemistry, and asset-life extension have



2. Ultra-centrifuge (UC) and membrane patch colorimetry (MPC) tests provide complementary views of varnish precursors and insoluble contamination. Results should be trended; an MPC value above 20 indicates elevated deposit risk

the top for continuous circulation (Fig 3). The turbine does not have to be running. In his view, that is what allows the unit to work both during operation, when dissolved varnish concentration is high, and during downtime, when settled contamination can be picked up before restart.

Malec's field comments were useful here because they moved the discussion out of theory. He said the Duke sites under his watch have "somewhere north of 80,000 gallons of oil" in service, a large enough inventory to make careless replacement thinking expensive. He also said one power block at his station was built 19 years ago and still carries its original oil charge, with makeup oil added over time for leaks, outages, and tank cleaning, but without a wholesale drain-and-refill event. That does not prove every plant can reach the same result. It does show the scale of life extension possible when contamination control and monitoring are sustained.

Malec also described the importance of ownership. He called himself the owner of the oil and grease program at his station, which fit well with Rowland's later argument that every site needs a champion who is accountable for oil-health decisions. In a thinly staffed plant, that matters. Rowland noted that many users are trying to do work once spread across larger maintenance organizations, and that a reliability program only works if somebody owns the practices, the trending, and the follow-through.

Freeman added another useful layer by warning users not to treat OEM and industry specifications as a complete maintenance strategy. Baseline specs matter, but they are minimums, not the whole playbook. He urged attendees to stay current with the latest OEM guidance and to recognize that oil formulations and additive packages change over time, sometimes in ways that

look small on paper but alter field behavior.

Q&A stayed in the field

The strongest part of the webinar may have been the closing question period because it stayed close to the day-to-day problems users actually face. One thread dealt with synthetic oils and changing formulations. Freeman said plants should not assume the oil going into a system today behaves like the oil qualified years earlier, even when the label looks familiar. As he put it, "don't count on that stuff being linear." Later in the discussion, panelists recommended benchmarking in-service analyses against recent new-oil samples, not against a virgin-oil data sheet from a decade ago. That advice matters because additive systems evolve, and a trend that appears flat against an outdated reference can still hide loss of margin.

Another discussion centered on how to

verify claims made for small varnish-treatment systems. The answer was not to trust branding language. Panelists pointed instead to before-and-after sampling, inlet and outlet comparisons, and case-study evidence that shows whether varnish precursors are actually being removed. Questions on soapy residues produced another practical answer: deposits of that type can come from water, contamination, degraded oil, depleted additives, or even grease introduced during major overhauls. In other words, the residue itself is a symptom, not a diagnosis.

Attendees also asked about ion charge bonding systems. The response was cautious. Speakers said such systems can remove some material but questioned their effectiveness and economics in large mineral-oil volumes where varnish precursors are dissolved at operating temperature. Malec was more direct, saying he has some ICB units in noncritical applications and has "not [had] very good luck with them."

The final Q&A points touched lead times, unit footprint, rental availability, and what equipment a user might need beyond a gas-turbine varnish unit. Those questions widened the discussion from varnish alone to broader oil conditioning. Malec noted that PTUs also deserve attention, especially on steam-turbine systems. Another speaker added that cycling can worsen water ingress through shaft seals, making water control a growing concern alongside varnish.

The webinar's bottom-line lesson was sound. Oil should be treated as a managed asset and a reliability indicator, not as a consumable to be ignored until a sticking valve or bearing problem forces action. Freeman supplied the best shorthand for that philosophy early in the session. Get in front of it. For combined-cycle plants trying to run harder, cycle faster, and stretch asset life longer than designers originally imagined, that is no longer just good housekeeping. It is reliability work. [ccj](#)



3. An off-line varnish-removal unit draws oil from the bottom of the reservoir and returns conditioned oil at the top, removing dissolved varnish during operation and settled contamination during outages

Pump health audit sharpens outage planning

Planned work outages are an exercise in efficiency and preparation. As global power demand continues to increase, plant operators are compelled to execute required maintenance within increasingly shorter outage windows. The pressure on already stretched labor resources and the strict O&M budgets compounds the challenge of outage planning. Getting better information on equipment health offers distinct advantages when deciding where and when to allocate time and capital.

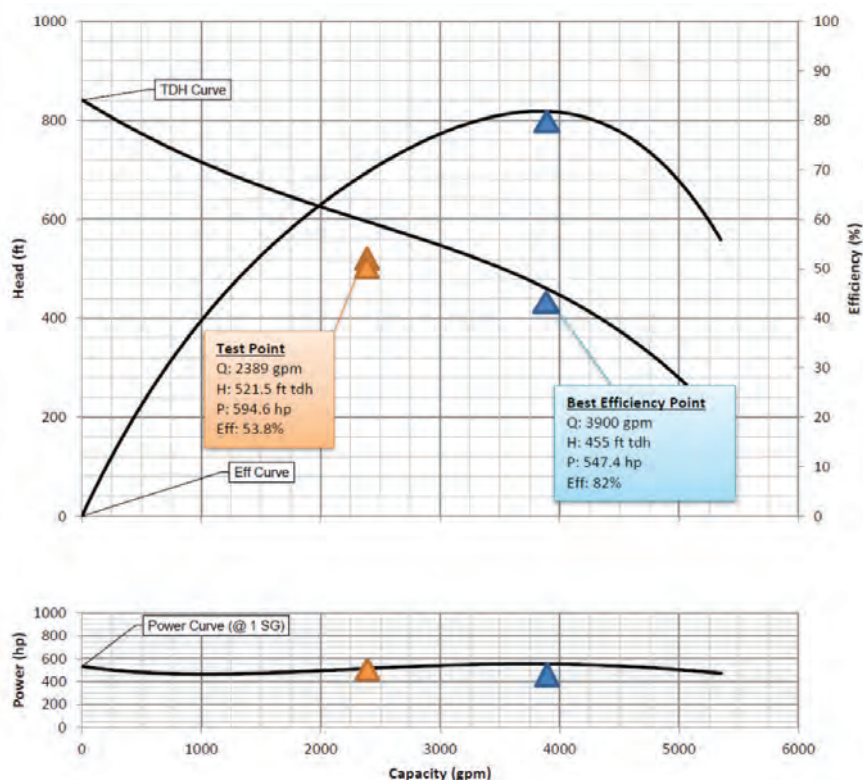
SHIFTING FROM PREVENTATIVE TO PREDICTIVE MAINTENANCE

Historically, maintenance decisions are based on a preventative, or time-based, maintenance strategy. Under this model, maintenance intervals are established using historical information, such as past mean-time-between-failures (MTBF) and equipment condition records from previous inspections and overhauls. The intent is to establish routine overhauls at intervals shorter than any expected failure mode. While this is generally effective at preventing unexpected failures, this approach frequently leads to unnecessary refurbishment of equipment that still possesses remaining useful life. Not only does this drain maintenance budgets and extend outage timelines, but it also exposes equipment to the risk of 'infant mortality' caused by reassembly or installation errors.

So what options are available to move from a time-based maintenance strategy to a strategy where decisions can be made based on actual equipment condition?



1. Condensate extraction pump



2. Degradation of "A" pump performance from tested curve

Transitioning from a time-based strategy to a predictive, condition-based maintenance strategy requires an accurate assessment of current equipment health. It also requires the ability to identify signs of degradation and understand how this degradation will impact future equipment operation. Many facilities lack the necessary instrumentation to capture the data required to make this assessment or the specialized subject matter expertise required to translate this raw data into actionable information.

Recognizing the benefit of condition-based decision making, a combined cycle end user in the Northeast sought an accurate picture of equipment health before scheduling maintenance of their condensate extraction pumps (Fig 1). They engaged with Hydro's field engineering division, Hydro Reliability Services, to perform a full health audit on this equipment to understand where to best concentrate their resources.

FIELD TESTING PROCESS

The health audit conducted at the CCGT facility encompassed both field testing and

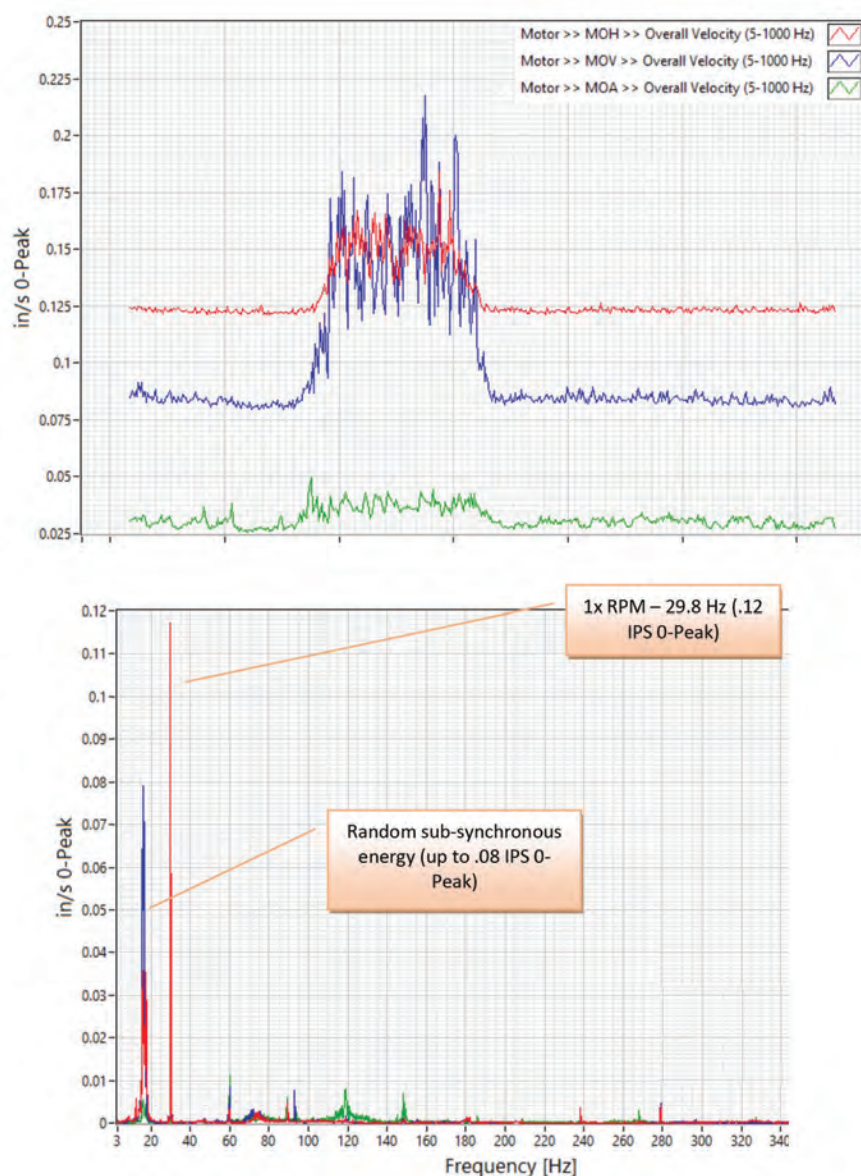
a rigorous review of equipment design and history. The primary objective was to evaluate the mechanical and hydraulic health of the equipment under typical operating conditions.

The pumps tested were two condensate extraction pumps of the vertical can configuration. Each pump is rated for 100% of the plant load. The pumps take suction from the condenser hotwell and discharge through an economizer to the LP drums that feed the boiler feed pumps. Tested parameters included:

- Hydraulic: Suction flow (gpm), suction and discharge pressures (psig)
- Electrical: Motor volts (vac) and amperage (amps)
- Mechanical: Pump speed (rpm), vibration signatures in velocity (ips), displacement (mils), and acceleration (Gs)
- Thermal: Thermographic imagery

TEST RESULTS

The field-test data clearly showed that the "A" condensate extraction pump showed signs of significant degradation. Indications



3. Vibration event on “A” pump

of substantial wear were evident in both the hydraulic and the mechanical parameters measured. The total develop head as measured was 12.5% than the head on the tested performance curve for that flow point; the efficiency at this point was 15.2% lower than expected. As would be expected with the degradation in efficiency, the brake horse-

power at this point was 14.3% higher than what was indicated on the factory test curve (Fig 2).

During the field testing, the “A” pump experienced a notable vibration event. For approximately 6 minutes vibration amplitudes in the outboard motor measurement locations increased. While the amplitudes did

not exceed the first alarm level, the pattern was still concerning. At this same time, the suction flow trend showed a slight increase. During this time, the subsynchronous energy increased at approximately 54% of the run speed (Fig 3).

Conversely, the test data of the B condensate pump showed that it was in good health both hydraulically and mechanically. Although slightly lower in efficiency than expected, the total developed head was very close to the test curve and there were no anomalies in the vibration data.

EVALUATION OF THE TEST DATA

Following the testing phase, the data was reviewed to evaluate the best path forward for O&M. It was clear that pump “A” was in need of an overhaul to restore the equipment to its original design clearances.

Both the degradation in performance (head and efficiency) and the mechanical issues could be attributed to excessive running clearances caused by component wear. The close clearance areas of the pump limit internal recirculation; opening these clearances will increase recirculation and decrease efficiency. The close clearance areas also contribute to rotor stiffness and stability, which explains the subsynchronous vibration anomalies.

With this data in hand, the site was able to schedule refurbishment of the A pump with confidence that the capital expenditure was fully justified. In the interim period leading up to the outage, the plant was able to immediately realize cost and energy savings by prioritizing the operation the “B” pump, which test data had proven was more efficient and required less horsepower to operate.

Ultimately, this case study underscores the tangible benefits of getting an accurate picture of equipment condition as part of the outage planning process. By investing in a comprehensive health audit, the plant avoided the costs and risks of unnecessarily tearing down healthy equipment, while accurately forecasting the required budget and parts for the degraded unit. By using specialized testing such as health audits, plants can confidently transition to a condition-based strategy, ensuring that labor and capital are deployed only where the data proves they are needed most. [ccj](#)



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Clyde Maughan: A legacy of knowledge freely shared

A LIFE BUILT ON RELIABILITY

Clyde V. Maughan died Feb. 7, 2026, at age 99, leaving behind the sort of record the power industry rarely sees and never forgets. He earned a BS in electrical engineering from the University of Idaho in 1950, joined General Electric in Schenectady that same year, spent 36 years with the OEM, then spent another 36 as an independent consultant. Those numbers matter. So does the fact that after closing his consulting business at 95, he still took calls from CCJ editors when they wanted to avoid getting something wrong. Even after two strokes, he remained mentally sharp, still diligently tending a community raspberry patch and flower bed.

That combination of durability, precision, and generosity is why Clyde was more than a generator expert. He became a trusted backstop for an industry that knew exactly whom to call when the problem was hard and the answer had to be right.

The roots of that life were far from Schenectady. Clyde was born July 5, 1926, in Lava Hot Springs, Idaho, the ninth and youngest child of John Raymond and Lera Clark Maughan. On the family's 1200-acre farm, only about 20% of the land was suitable for crops, and the short growing season at 5200 ft left little room for error.

Before rural electrification reached the property, the farm relied on a Delco 24-V system with a small gasoline engine, DC generator, and wet-cell batteries. Clyde remembered it as marginal, a few light bulbs when it ran, dead batteries when it stopped. He also remembered the danger: one evening his father discovered the gasoline storage tank on fire while preparing the unit to run. When the Rural Electrification Act changed farm life, Clyde never forgot what reliable power meant in practical terms.

FROM AN IDAHO FARM TO A LIFE IN ENGINEERING

That childhood helps explain why Clyde's engineering life never drifted into abstraction. Five days after his 18th birthday, a month after D-Day, he enlisted in the US Navy, trained as an aviation electrician, advanced to Aviation Electrician's Mate 2/c, and was discharged in July 1946. He returned home carrying the weight of what the war had cost his town; of the Lava boys who turned 18 from 1938 through 1944, at



Clyde V Maughan is a member of the Greatest Generation—those who experienced the depression, survived WWII, and contributed to the country's economic development for the benefit of all

least one-third were killed.

Years later, he helped organize and finance the World War II monument dedicated in Lava Hot Springs in September 2000. Between those two points came college, marriage, and the move east. He met Norma Rollins in the orchestra, he on French horn, she on alto clarinet, and they married in August 1947. In 1950, Clyde, Norma, and their young son Bruce headed east in a 1949 Plymouth.

At GE, Clyde found the work that would define him. He wrote the first version of a common generator evaluation test in 1952, a document he said remained in use decades later with only minor revision. He moved through field service in San Francisco, application engineering, manufacturing, insulation-system development, and product service, holding 11 jobs in all during his 36 years with the company. He became the first generator engineer assigned to a man-

ufacturing group, trained service personnel to replace stator windings without factory winders, and rewound more than three dozen large generators without incident, saving the company millions of dollars. He also earned a master's degree in mechanical engineering. Clyde said he had been fortunate to work with a few absolute geniuses. More important, he paid that luck forward.

He thought retirement would mean taking care of the farm and, in his memorable phrase, fixing toasters for little old ladies. The phone rang two months later, and the second act began. Clyde's consulting career grew into more than 300 non-GE assignments on generators of every size and vintage. A one-year GE retainer turned into six years of work training field engineers, building a team from 24 untrained service personnel to 72 well-trained and equipped engineers, and rewriting roughly 400 pages of GE rewind instructions.

He wrote a 240-page handbook on generator maintenance, presented more than 30 seminars built around about 1500 slides to more than 1000 attendees worldwide, produced a library of technical papers, recorded seven generator-maintenance webinars with CCJ, and helped launch the Generator Users Group in 2015. He also gave many hundreds of hours of free advice by phone and email. Clyde never treated knowledge as inventory to be rationed.

WHEN CLYDE SPOKE, THE ROOM LISTENED

That duty changed how people behaved around him. In CCJ's recent note on Clyde's 99th birthday, GE Vernova executive Tom Freeman recalled the first annual Generator Users Group meeting in 2015. In a room full of seasoned engineers, Freeman watched people stand when Clyde entered, go silent when he spoke, and seek his counsel throughout the conference. Kent Smith, then the group's chairman, recognized him for a lifetime of sharing selflessly his knowledge of generator design, operation, and maintenance.

Respect like that does not come from title alone. It comes from years of being right for the right reasons, especially when a generator failure, an outage plan, or a repair strategy is expensive enough to make everyone in the room nervous.

Clyde also left a practical model for how an expert should behave. He resisted legal work because he believed it was often a poor use of an engineering mind, and when he did accept such assignments, he told lawyers he would help find the facts, not help win the case. He was equally blunt with clients who were headed toward unnecessary work.

In one case at MIT's fusion laboratory, after others had urged a stator-winding replacement, Clyde recommended two simple tests and, once the winding passed, said the machine should be returned to service and inspected again in 200 years. In another



Generator Users Group Chair Kent Smith (left) presents the inaugural Maughan Award to its namesake—and most deserving first recipient—Clyde Maughan in 2015

case, he urged a San Antonio owner to run rather than rush into a costly outage, and the unit operated for years without incident. This was not showmanship. It was judgment, grounded in experience and delivered without drama.

KNOWLEDGE WAS MEANT TO BE SHARED

The trade-off Clyde kept making, in one form or another, was between holding knowledge close and giving it away. He chose the harder and more useful path. He wrote the handbook instead of keeping his methods proprietary. He built seminars because he knew few people would learn enough by simply reading the book. He recorded webinars so owner/operators who could not afford custom training still had access to solid instruction. He even helped future competitors get started in consulting. In a field where expertise can be monetized by scarcity, Clyde chose reach.

He made a similar choice between ego and service. His autobiography is full of stories in which he challenged bad conclusions, argued with managers, or refused to shade the facts for a client. But the motive was never self-display. Clyde's own summary of his consulting years is more revealing than any compliment. He wrote that money was not why he did the work. The work was great

fun, and he would have done it for nothing beyond expenses.

That attitude explains why his influence traveled so far, from GE field crews and utility engineers to conference attendees, readers, webinar viewers, and colleagues looking for a clean answer to a difficult failure. People trusted him because he was trying to solve the problem, not enlarge himself.

CARRYING CLYDE'S LESSONS FORWARD

The right way to remember Clyde Maughan is to use the tools he left behind and copy the habits that made those tools valuable. Read the handbook. Use the webinars. Support the Generator Users Group. Tell younger engineers what the older generation learned before it disappears. Defend facts when pressure builds to dress them up or bend them. And remember that the same discipline carried through the rest of his life.

He and Norma built a 73-year marriage, raised six children, and kept faith with the town, church, and industry that shaped them. From a farm lit by a fragile 24-V system to a 72-year career in turbine-generators, Clyde helped others do the work better. That is as strong a legacy as an engineer can leave.

Rest in peace, dear friend. You mean so much to the CCJ family.

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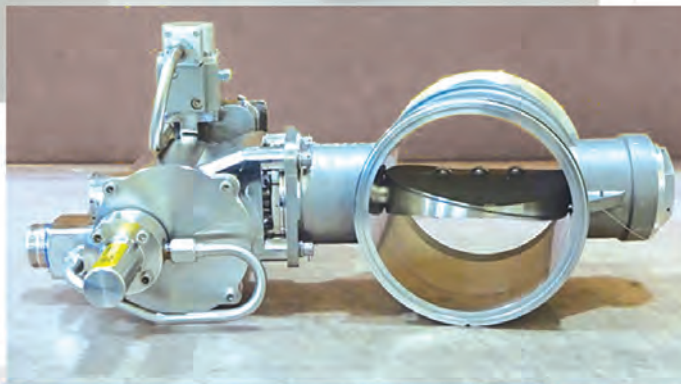


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