Issue 83 (2025)
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- STEAM TURBINES
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SINCE CCJ 2003

COMBINED CYCLE JOURNAL

Black Point Power Station, Hong Kong

USER GROUP REPORTS

FEATURES

BEST PRACTICES

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

UPCOMING GT INDUSTRY EVENTS

Combustion Turbine Operations Technical Forum (CTOTF)
September 21-25

50th Anniversary Conference and Vendor Fair, La Quinta Resort & Club, Palm Springs, Ca. Details/registration at www.ctotf.org. Contact: Christine Doyle, chrisdoyle@ctotf.org.

HRSG and Boiler Forum: América Latina
September 23-25

First Annual Conference, Blue Tree Premium Morumbi, São Paulo, Brasil. Details/registration at www.hrsgamericalatina.com. Contact: Bianca Carreira, bianca@hrsgamericalatina.com.

Wärtsilä Users Group
September 29-October 2

Silver Legacy Resort, Reno, Nev. Details/registration at www.powerusers.org. Contact: Jacki Bennis, jacki@somp.co.

Advanced-Class GT Users Group
November 11-14

EPRI Main Campus, Charlotte, NC. Details/registration at www.epri.com/events. Contact: Nick Smith, nsmith@epri.com.

Vogt Combined Cycle Seminar
Mid-January

Omni Grove Park Inn, Asheville, NC. Contact: Jennifer Pasquariello, jpasquariello@babcockpower.com

PEC 2026
January 26-28

Arizona Grand Resort, Phoenix, Ariz. Details/registration at www.proenergyservices.com. Contact: Chris Evans, cevans@proenergyservices.com.

PSM Asset Managers Conference
January 26-28

Wyndham Grande at Harbourside Place, Jupiter, Fla. Details/registration at www.psm.com. Contact: Michèle McDermott, Michele.McDermott@us.psm.com.

501F Users Group
February 15-20

Hilton Norfolk – The Main, Norfolk, Va. Details/registration at https://forum.501fusers.org/. Contact: Jacki Bennis, jacki@somp.co.

501G Users Group
February 15-20

Hilton Norfolk – The Main, Norfolk, Va. Details/registration at https://forum.501gusers.org/. Contact: Jacki Bennis, jacki@somp.co.

FT8 Users Group
March 17-19

EPRI Main Campus and Marriott University Place, Charlotte, NC. Details/registration at www.ft8users.com. Contact: Ashley Potts, ft8@ft8users.com.

FT4 Users Group
March 17-19

EPRI Main Campus and Marriott University Place, Charlotte, NC. Details/registration at www.ft4users.com. Contact: Ashley Potts, ft4@ft4users.com.

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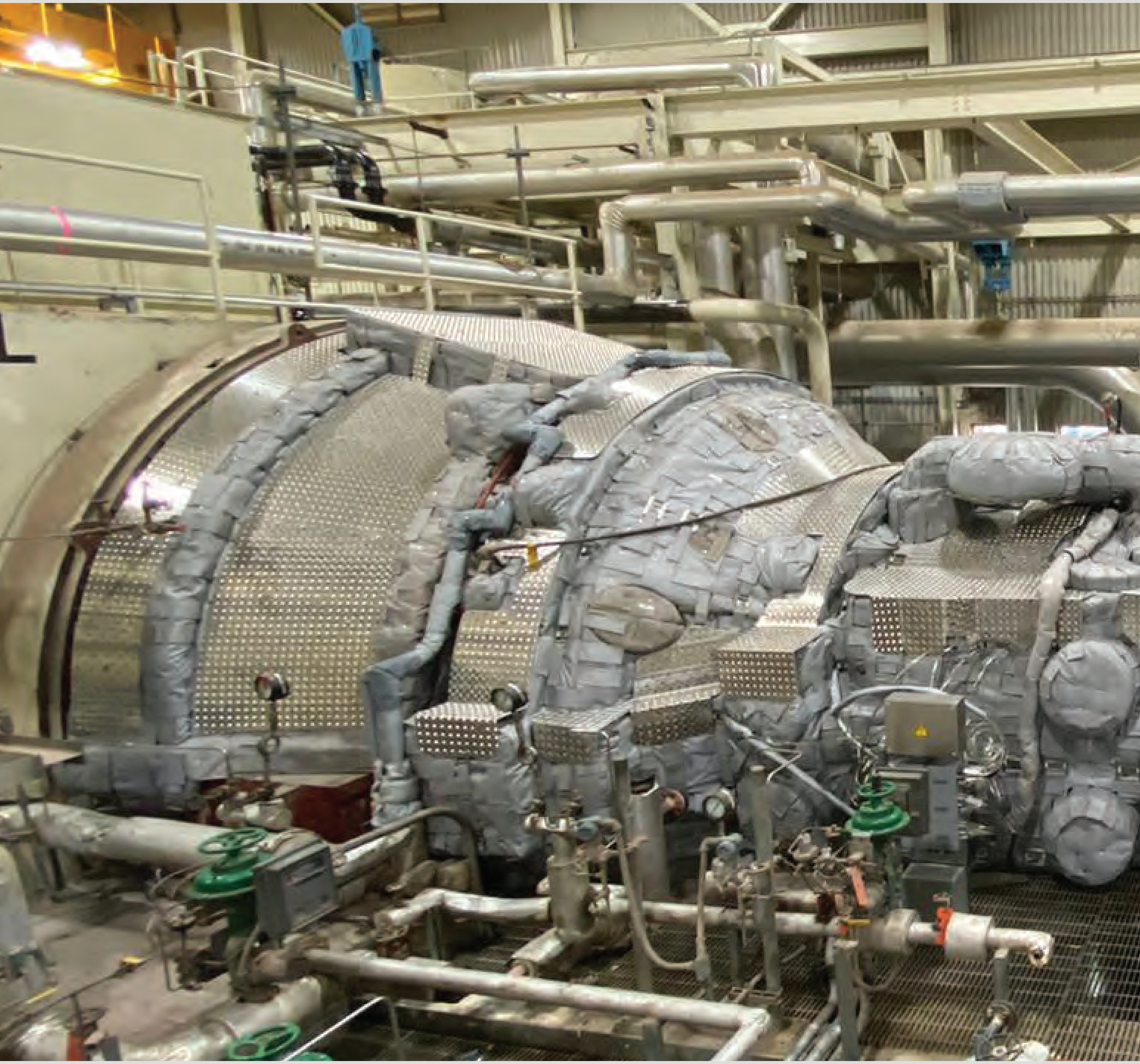
Advanced Single Layer Steam



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Washington, D.C.
August 25–28, 2025

Improvise, adapt, overcome: Navigate power's new frontiers

In a period of accelerating change across the power generation industry—shaped by decarbonization goals, shifting market pressures, and the realities of an aging fleet—the 2025 Power Users Combined Conference presents a timely opportunity to learn, adapt, and prepare your team for what's next.

From August 25–28 in Washington, D.C., this multi-group forum brings together five of the industry's most engaged user communities: the Combined Cycle Users Group (CCUG), Steam Turbine Users Group (STUG), Generator Users Group (GUG), Power Plant Controls Users Group (PPCUG), and Low Carbon Peer Group (LCPG). Each user group delivers its own targeted agenda, while cross-over sessions, joint panels, and the always-valuable vendor fair create space for the kind of peer-to-peer knowledge transfer that no online training or webinar can replicate.

If you manage, operate, maintain, or support combined-cycle assets, the wide range of technical content provides direct insight and actionable information from users, solutions providers, and OEMs.

OPERATIONAL RESILIENCE AND PERFORMANCE TUNING

CCUG's agenda is built for hands-on plant professionals looking to boost efficiency, reduce forced outages, and extract more life from aging equipment. This year's program covers an impressive range of topics—from water treatment's impact on heat rate to operator-guided troubleshooting of SCR performance.

Day one features a deep dive from ChemTreat on optimizing plant chemistry for thermal performance, followed by presentations on GT upgrades and HRSG re-rates, inlet cooling economics, and cybersecurity briefings. The "Operator Experience" session hosted jointly by CCUG and PPCUG steering committees offers a grounded look at real-world scenarios and what's working in the field.

Over the week, speakers from GE Vernova, Emerson, HRST, Tetra Engineering, Cutsforth, NAES, Siemens Energy, and others will share insights on duct burner issues, instrument calibration, static starter reliability, LCI maintenance, steam path modernization, and asset care strategies. Combined with robust roundtable participation and targeted case studies, CCUG is a must for anyone supporting a CCGT fleet.

DAMAGE MITIGATION AND STRATEGIC MODERNIZATION

STUG's track focuses squarely on reliability, asset life extension, and outage execution—particularly for plants with D-11 units or high-hour baseload machines.

The week opens with a three-part series from EPRI on high-temperature casing cracking, last stage blade (LSB) erosion mechanisms, and alignment drift. Follow-up sessions dig into real-world challenges including performance loss quantification, weld repair best practices, and outage lessons learned from the user community.

Tuesday's agenda dives into efficiency-boosting retrofits, including packing ring upgrades, oil filtration strategies, and cladding to mitigate erosion and corrosion. A standout session features MD&A's take on D-11 replacement planning, while Siemens Energy will address balance-of-plant impacts on steam turbine behavior and synchronous condenser conversions.

Wednesday and Thursday offer OEM guidance and plant-tested solutions on topics such as bolting maintenance, diaphragm repair, rotor crack fixes, AI-assisted diagnostics, and advanced steam path upgrades. The sessions culminate in GE Vernova's showcase of its parts and repair network and a forward-looking roundtable on priorities for 2026.

ROOT CAUSE, ROTOR RELIABILITY, AND REWIND READINESS

GUG strives to bring clarity to one of the most complex and critical plant assets. With frame sizes aging and rewind demand outpacing shop capacity, the 2025 GUG agenda focuses on proactive troubleshooting, field testing, and failure prevention across both rotor and stator systems.

Day one begins with dual sessions on relay protection troubleshooting, followed by plant-side presentations on acoustic and vibration analysis, core foreign material exclusion (FME), emergent field replacements, and stator failure diagnostics. The highlight here is the back-to-back "Field Testing 101" and "Stator Testing 101" led by AGT Services, offering attendees practical benchmarks for testing, interpretation, and repair decision-making.

Throughout the week, users will hear RCA findings and fleet lessons from GE Vernova, Constellation, Southern Company, Calpine, NV Energy, and others. Sessions cover rewound rotor failures, bowed cores, magnet-related lead degradation, thermal sensitivity, and centralized data strategies for diagnostics and monitoring.

The final day belongs to Siemens Energy, who will present a wide-ranging series of sessions on actuator technology, controls training, fleet performance analysis, and generator reliability during this energy transition. If your site has a generator in service for more than 15 years—or you've got a rewind on the horizon—GUG will help you plan smarter.

CONTROLS RESILIENCY, DIAGNOSTICS, AND CYBERSECURITY

Modern controls systems sit at the intersection of plant performance and risk—and the Power Plant Controls Users Group (PPCUG) addresses both. From Mark VIe architecture to cybersecurity best practices and vibration condition monitoring, PPCUG brings together control engineers, I&C staff, and operations teams to share experience and sharpen systems awareness.

GE Vernova anchors the opening day with a hands-on Mark VIe training series, moving from beginner to advanced topics. Sessions cover plant-wide controls lifecycle planning, BOP integration, simulator use, flame detection advancements, vibration monitoring, and alarm management optimization. The evolving cybersecurity landscape is also front and center, with presentations from both OEMs and end users on risk and readiness.

Later in the week, Emerson, ABB, SEL, AP4 Group, Environex, BK Vibro, Alta Solutions, and others tackle practical applications: centralized relay networks, historian-based analytics, health checks, and intelligent valve actuation. Whether you're defending against obsolescence, integrating third-party systems, or trying to optimize plant controls for decarbonized operation, PPCUG delivers technical grounding with real-world relevance.

DUCKS IN A ROW

If you're responsible for O&M, outage execution, controls reliability, or generator and steam turbine health, this is your conference. Go to www.powerusers.org, download the agenda, and build your curriculum.

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GUG GENERATOR USERS GROUP

Low Carbon Peer Group

POWER PLANT CONTROLS USERS GROUP

STUG STEAM TURBINE USERS GROUP

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Club 99 welcomes Clyde Maughan

There's something about the number ninety-nine that makes it particularly noteworthy in the minds of many people.

Perhaps because it is associated with some of the most gifted professional athletes—such as Wayne Gretzky (hockey), George Mikan (basketball), JJ Watt and Warren Sapp (football), and Manny Ramirez and Aaron Judge (baseball).

Perhaps because Agent 99 (Barbara Feldon) was Maxwell Smart's partner in the sitcom "Get Smart."

But for CCJ subscribers, it was generator guru Clyde Maughan's 99th birthday (July 5). Although he officially retired from professional work at age 95, The Clyde's continuing guidance is revered by the editors.

In our view, he certainly deserves GOAT recognition from the electric power industry for sharing unselfishly his extensive generator experiences acquired over more than 70 years of work at General Electric's Schenectady works and as a technical consultant.

What Maughan means to the industry is, perhaps, best described by Tom Freeman, a GE Vernova executive well known to power generators who recently "retired" and formed a consultancy (thomas.freeman@gasturbinecoach.com).

Freeman told the editors, who agreed, that every so often you're fortunate to meet someone you know to be an industry giant. Freeman said, "I think the esteem that the industry holds for Clyde can be summed up by something I witnessed at the first annual meeting of the Generator Users Group (GUG) in 2015.

"In a room full of, dare I say, seasoned engineers wearing progressive lenses and sporting a fair amount of gray hair, I watched various people stand when Clyde entered the room, go silent when he spoke, and generally seek his counsel throughout the conference. Maybe I'm simply old enough to appreciate that, but I would say that it is the high honor that has been well deserved through decades of engineering excellence."

The first GUG conference, held in NV Energy's Beltway Complex and Conference Center, welcomed 70 participants and featured 20 presentations. The speakers, including four IEEE Fellows and one ASME Fellow, each was expert in his field, several having worldwide reputations.

Maughan, the force behind the formation of the GUG, was recognized by the user group's chairman, Kent Smith, for a "lifetime of sharing selflessly his extensive knowledge in the design, operation, and maintenance of electric generators." Smith was a Duke Energy employee at the time with fleetwide generator responsibilities. Today he is an independent generator consultant (kentnsmithllc@gmail.com).

The Clyde sporting his hall-of-fame jersey on 99th birthday in upstate NY

Interestingly, two members of the GUG's original steering committee—Joe Riebau, senior manager of electrical engineering and NERC for Constellation Power, and Jagadeesh (JD) Srirama, a senior electrical engineer at NV Energy—continue on the committee. Visit with them and other colleagues in the generator community by registering for the 11th Annual GUG Conference, August 25-28, in Washington, DC (details at www.powerusers.org).

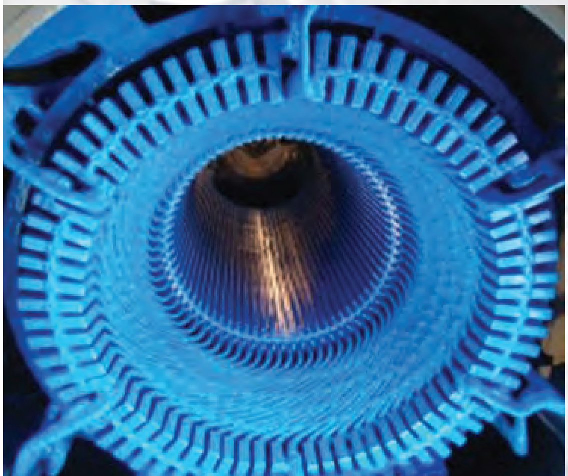
Where life began. Clyde was born into a large, self-sufficient Idaho farm family at the mercy of weather, insects, and anything else that could impede the growing of food necessary to sustain life. His first association with the "power industry" came as the family member responsible for fueling the small gasoline engine/generator used to charge the batteries supplying power to the farm's microgrid. These were the long-ago days before the Rural Electrification Administration provided the wherewithal to deliver power by wire direct from federal dams in the state.

Maughan spent the first 36 years of his career after graduation from the Univ of Idaho (BSEE, 1950) at GE as an engineer and manager in generator and turbine engineering design/service/development/manufacturing and a variety of other positions. He launched Maughan Engineering Consultants after retiring from the OEM.

Along the way to his second retirement, The Clyde was directly involved in 250 or so repair projects on generators from 2 to 1400 MW supplied by virtually all of the world's major manufacturers. This work included several dozen root-cause investigations of complex failures on stator and field components.

Plus, Maughan served on several IEEE and IEC committees and working groups; managed a couple of major projects for EPRI; wrote or coauthored more than two-score major technical papers; published a handbook of more than 200 pages on generator repair and conducted nearly three dozen seminars (total of more than 1000 attendees) worldwide based on that work; and still had time to get an MS in Mechanical Engineering. Plus, he earned his Professional Engineer's certification (since retired voluntarily) and was named an IEEE Fellow.

The Clyde's greatest achievement might well be his handbook, "Maintenance of turbine-driven generators" first published in 1997 and updated several times since. Access this valuable treatise at no cost by visiting www.ccj-online.com/maughan-book or scanning the nearby QR code. CCJ



Life-long learning abounds across five user group conferences

COMBINED CYCLE USERS GROUP · GENERATOR USERS GROUP · Low Carbon Peer Group · POWER PLANT CONTROLS USERS GROUP · STUG STEAM TURBINE USERS GROUP

The question these days becomes why *wouldn't* you send as many of your plant staff as possible to 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?

As amply exhibited in the following write-ups from the 2024 mega event (supporting slide decks available to end users registered at www.powerusers.org), the potential opportunities for collaboration, sharing, and learning from your peers represent value that far exceeds the investment in man-days, conference fees, and travel expenses. There's still plenty of time to register for the 2025 edition taking place in Washington DC from August 25-28.

In recent years, the various steering committees have added healthy doses of training and refresher courses for the growing fraction of attendees who are relatively new to powerplant equipment and/or attending for the first time. These are in addition to the bread and butter sessions and roundtables on user-driven O&M experiences and failure causes and recovery, along with the latest vendor solutions and new technologies.

STUG and PPCUG kicked off with "Navigating Power Trends" offered by GE Vernova's Jeff Chann on big picture topics like pace of asset retirements, grid emergencies, load growth, addition of renewable generation assets, and environmental regulations. Meanwhile, GUG and CCUG dove right in with tutorials, training, component trouble shooting, and roundtable discussions.

The formal CCUG welcome and kickoff session included the presentation of the Individual achievement award to Bill Lovejoy, NAES, who then offered some thoughts on how lifelong learning improves O&M (Fig 1). This was followed by two representatives from the Turbine Inlet Cooling Association presenting on maximizing the economic performance and electric grid decarbonization potential of CCGT systems, specifically how GT inlet cooling mitigates the impact of hot weather on plant revenues and carbon footprint. Later in the day, an FBI Special Agent from a regional office made some remarks on terrorism.

The relatively new (to the Combined Conference) Low Carbon Peer Group featured a detailed dissection and discussion of EPA Rule 111; a topic also covered in "Navigating Power Trends." The rule would have profoundly affected options for keeping existing and future CC and GT facilities in compliance with carbon restrictions.

However, any information imparted to the audience about emissions and environmental compliance, especially CAA section 111, is probably moot now that the Trump Administration has converted the EPA from a regulatory agency to a cheerleader for American manufacturing, industry, and energy production, distribution, and consumption. Many in the user community will undoubtedly praise this reversal, but it does add yet another level of unpredictability to long-term planning.

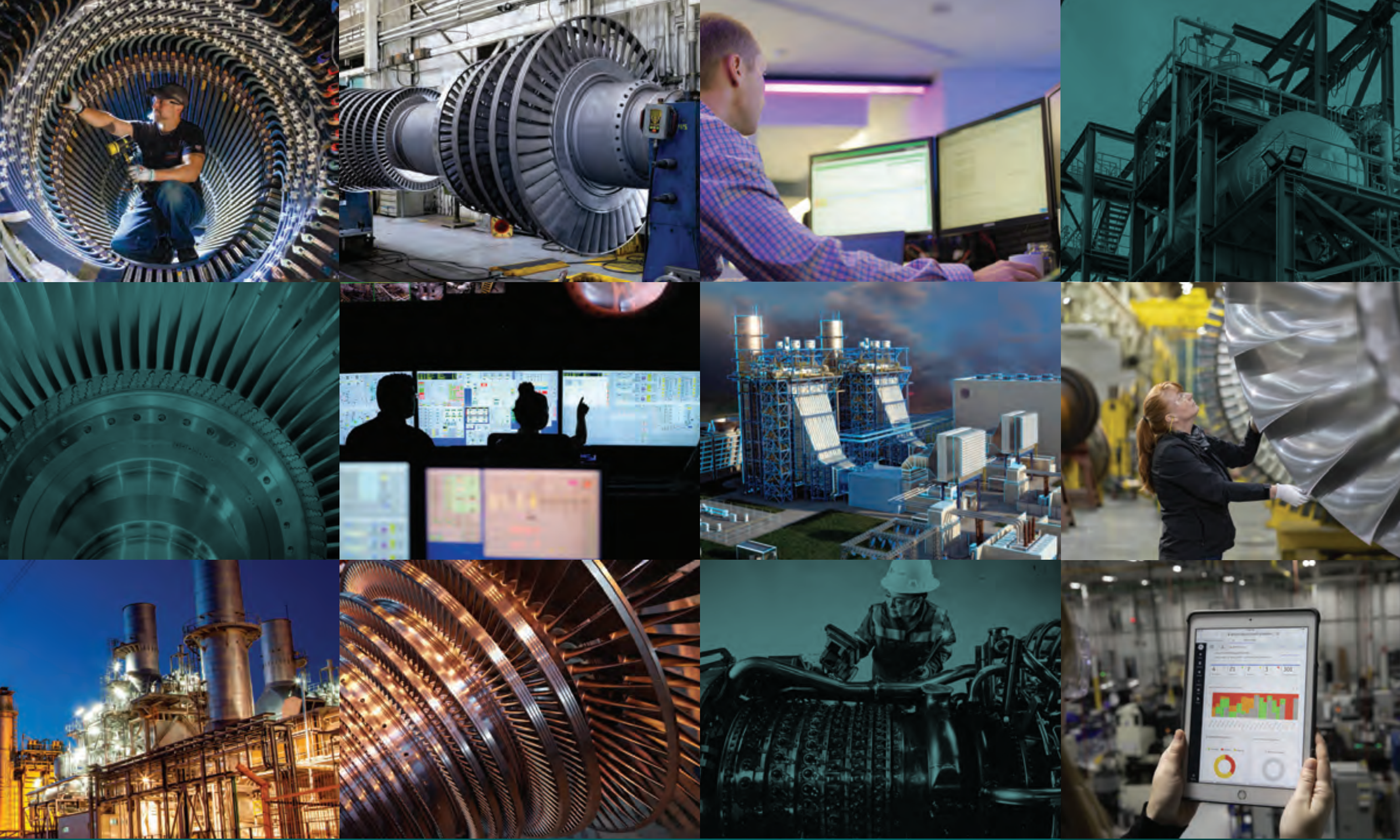
Keep in mind that, in keeping with recent practice at user conferences, the GE and Siemens slide decks are not available at the Power Users site. However, CCJ was able to capture some of the GE content from notes taken during attendance. One example is from a presentation, "CC Forced Outage Drivers," an analysis of three years of unplanned outages between 2021 and 2023.

It probably comes as no surprise that the gas turbine (GT) was responsible for 55% of the 19,000 fleet events and 800,000 hours of total downtime, generator 20%, steam turbine/generator 10%, HRSG 2.5%, balance of plant (BOP) 10%, and other 4%. Electrical systems account for 40% of downtime and 19% of events, far and away the subcategory with the largest impact. 20% of the events are longer than 24 hours in duration.

Another piece of insight: HRSGs behind upgraded GT/Gs are experiencing more damage after the upgrade.

Another CCUG roundtable towards the end of the Thursday sessions dealt with "How to temporarily deal with plant failures while you work on permanent solutions." Topics covered include steam and water leaks, more frequent borescope inspections to track known issues, and adjusting the operating mode until repairs can be made. In the last category are open cycle (100% steam bypass to the condenser), protecting equipment following abnormal operations, and performing a "test run" to determine limitations under abnormal operating conditions.

1. The CCUG steering committee honors the long-lasting engineering contributions of Bill Lovejoy (center) to the power-generation industry



BEYOND THE GAS TURBINE

Redefining Plant Life Extension

As the energy landscape evolves, so must the systems that power it.

Steam turbines, generators, controls, and HRSGs were built to last—but not forever. Rising demands and aging assets require more than maintenance.

GE Vernova goes beyond extending asset life—we help redefine it with smarter upgrades for improved reliability, output, and flexibility.

This is lifecycle management for a new energy era.

GE VERNOVA

Steam Turbine

Generator

Controls

HRSG

COMBINED CYCLE USERS GROUP

In recent years, winterization has become a hot topic for user groups, and this year's CCUG was no exception. One reason is that the next extreme weather event seems to challenge everything done to address the last one.

During the "Extreme Weather Operation" roundtable, the user facilitator noted that "bomb cyclone weather forced us to think differently about freeze protection because our existing systems didn't work well." He tagged thermostats as a prime example.

During another event, the facilitator noted that a lightning strike had taken out all their instruments. In a show of hands, seven in the audience indicated they had experienced trips from lightning. He also asked the audience about their lightning policy for venturing out into the plant, and most people raised their hands indicating that they had one. One guideline is if the lightning is ten miles out, everyone comes off the top decks. When two miles out, no one is allowed outside.

Some general tips from the discussion:

- Get a critical transmitter list together. Where and when possible, transmit data into the control room via blue tooth
- Try to eliminate having to get to the upper decks while things are freezing up
- Monitor heat tracing from the control room
- Make sure heat trace lines have not been inadvertently disconnected because of a closed electrical circuit
- Using open flames to defrost lines may require a hot work permit in areas where stray flammable gas may be present
- Red chicken coop lights are good for heating "hooches"
- Insulation should be part of your heat trace audit
- Develop quick drain guidelines for the HRSG
- Review alarm points and operational permissives which may be impacted by cold weather
- Review work orders that could identify leaking equipment

Suggestions for longer term investments from the slide deck include replacing heat trace (mineral insulation cable is only good for 10-15 years), replace sample lines with tube bundles, insulate drum enclosures and add cladding, and reinsulate and clad interior walls and ceilings. One slide has a convenient check list for both cold and hot weather operations.

"HP Steam Turbine Door Leaks" reveals how users at a 1997-vintage 1x1 baseloaded CC facility with a bottom-supported HRSG handled diagnosis and repair of a drum door leak which was causing forced outages on a unit expected to run without interruption eleven months out of the year (Fig 2).

The leakage pathway proved to be pitted drum and door seating surfaces, but bent and worn door hinge hardware and misalignment of door-to-drum sealing was also discovered. Because the leveling blocks did not work well for centering the door to the opening, plant staff resorted to workarounds which damaged key components. Worn bolts also led to workers over-torqueing to tighten and seal.

Overall solution involved phonograph-groove machining of the drum and door sealing surface, replacing internal hinge hardware and strongbacks, upgrading the leveling block and the bolting and nuts, as well as revising door closing procedures. Presenter noted that "putting the sealing gasket on properly" is critical. The revisions restored the plant team's "faith" in walking by the door. Responding to an audience question, the presenter said they did not perform a root cause analysis of the pitting.

"Hot Topics for Insurance" may have been presented by an insurance company official but is a must-read for users as an alternative view of the state of the industry. Quotes like these may get you to link to the slides: "Supply chain impacts have resulted in enormous and unexpected business interruption losses," "unprecendented amount of losses recently (with steam turbines)," [OEM] RCAs are not complete and issues may not be disclosed in a timely manner," and "[we are] starting to consider climate change and sea level rise."

This official argues that, in today's climate, a CC facility needs to "objectively differentiate itself" from its peers with respect to risk reduction and its relationship with the insurer. One way to avoid negatively distinguishing your facility is to make sure you have these bases covered, for which presenter notes that, despite better practices overall in power generation, some sites are not attending to:

- Planning for worst case scenarios such as steam turbine lube oil fire combined with overspeed event
- Functional overspeed trip testing
- Sequential tripping
- DC load/overload system design and testing (including during operation)
- Fire emergency response procedures
- Valve maintenance and testing
- Frequency of maintenance vis a vis run hours vs time and load conditions
- Starts and stops, NERC GADS (Generating Availability Data System) data, and run profile

Critical items listed include updated TIL and FSB (field service bulletin) trackers, borescope inspection frequency, fire protection and enclosure tightness testing, concern with overfiring for profit by IPPs, and life extension studies.

"Safety Valve Testing, Repair, and Programs" declares at the top that a "great testing program is essential" for ensuring safe and efficient operation of pressurized systems, but the advice at the end is no less insightful: "All inspections need to be documented or they never happened." Keep in mind that safety relief valves are also subject to industry standards (ASME, API), your insurance carrier's recommendations, and local jurisdictional regulations.

Slides include inspection frequency and recommendations for different classes and services of valves, examples of a work order cover sheet, repair and inspection report, and quality control guidelines.

"Outage Management, Planning, & Execution" ends with the important point that planning for the next outage begins immediately after the last one ends. Work that was not completed or needs to be revisited, and items from inspections and work orders will begin the task list for next time. Schedule your outage close-out meeting and reports deadlines as soon after the end date as possible to document lessons learned and future work when it is all top of mind.

The best of planning will not avoid discovery of emergent work scope. Don't knee-jerk respond. Work these items into the plan, understanding that the risk of errors and accidents is twice as high when addressing emergent situations.

Balance of slides address common components of outage planning: EHS issues, building the team (owner/operator, site personnel, contractors and vendors, OEMs and CSA partners) and the small teams with the team, budgeting and schedule, building the work list from the CMMS, work package development, planning and coordination (LOTO, cranes, special movers, scaffolding, parts, tooling, etc), RFQs preparation, outage execution and verification, and others.

"Drones" explains some basics of how to set up a drone inspection program, including FAA registration, regulations, and compliance; typical applications like inspecting external and internal stack surfaces, HRSG and turbine interior components, and high voltage transformer components. Drones save money, keep workers out of high-risk areas, and are often able to access tight and confined spaces. Numerous photos of drone-inspected equipment are included,

2. HP steam drum leak posed safety and reliability issues for a baseload 1x1 CCGT facility. Solution involved design and operating revisions

along with three types of drone units.

"Risk Management" is a basic framework used at one site for assessing various plant maladies with respect to impact on personnel safety, environmental compliance, cost, staffing/labor, and potential collateral impact on other plant components and systems.

Deciding how to address an emergent malady - whether to monitor it, attempt to mitigate it on-line, or take an outage and correct it - can challenge any risk management procedure. The detailed risk assessment and thought processes around an actual HRSG bellows leak (accompanied by key photos of damage) at the plant makes the framework actionable.

CCUG VENDOR PRESENTATIONS

"HRSG 101 and HRSG Cycling,"
Greg Rueff, Vogt Power International (Babcock Power)

Comprehensive 64-slide primer on HRSG design features and cycling impacts covers everything in the footprint, including duct burners, attemperators, catalyst and ammonia grid, insulation, liners, bellows, and casing seals. Those familiar with HRSGs may find the last few slides – covering cycling damage mechanisms (Fig 3), calculating damage factors, and maintenance planning – most relevant. It's always good to be reminded that "cycling enhances the action of all existing damage mechanisms."

"Condenser Troubleshooting and Restoring Condenser Health,"
Geoffrey Greenberg, TEI Babcock (Babcock Power)

Slides on troubleshooting are suitable for conversion into posters displayed by the unit. Later slides in the deck offer maintenance guidelines, best practices, diagrams and photos of typical issues, and case studies of recent projects undertaken by this vendor to address issues and restore performance.

"Turbine Oil Life Cycle Management,"
Chris Knapp, Shell Oil Products
Everything you need to know about lubricating oils in power plants, with a focus on testing and analysis, understanding and mitigating varnish issues, and why/how PAG-type fluids avoid varnish formation. Words of wisdom: "Not all lube oil products are created equal even if they meet the specs."

"The Importance of Testing and Cycling Your Electrical System,"
Nataniel Smith, TEMS
You probably are not cycling (testing that they work) your electrical components frequently enough, according to this presenter, nor is following NERC PRC-005 sufficient. Any electrical coil that actuates a mechanical device should be "operated" as frequently as possible. Guidelines are included for protection relays, lockout relays, AC sensing devices (e.g., current transmitters), and breakers.

"Safety Differently: A Story About How Your Organization Could Learn Differently," *Matt Barnes, MD&A*

Message here is that team performance improves when you work through a safety event with positives instead of the absence of negatives. Positives include the capacity to be successful under varying conditions, the ethical responsibility to the organization which has to handle messy, risky work, and making sure the people perceived to be part of the problem (those involved in the safety mishap) become part of the solution.

"AIG Tuning and System Maintenance,"
Andy Toback, Environex, and Kevin Perez, Groome Industrial

Ammonia injection grids can be tuned to improve NOx reduction performance and reduce ammonia consumption. Slides help you make a first order decision as to whether tuning will be beneficial for your unit(s). The procedure is described, along with sampling probe requirements, pros and cons of installing a permanent sampling grid, chemistry basics, results before and after tuning, plant preparation for "tuning day," operating requirements, access to sampling ports (sometimes sampling ports are not accessible). Because 7F units achieve 9 ppm NOx at the GT exhaust, they are generally not good candidates for tuning, note presenters.

"Attemperator Repair and Replace-

CYCLING EFFECTS ON HRSGs

Damage mechanism

HRSG component	Low cycle fatigue	Creep	Thermal shock	Differential expansion	Corrosion fatigue	OGE	Chemical corrosion	FAC	Corrosion product migration	Depositions	Tube erosion - inner	Tube erosion - outer	Tube corrosion - outer	NPP corrosion	NPP erosion	NPP expansion
Superheater	•	•	•	•		•	•				•					
Attemperator	•	•	•	•			•	•	•		•					
Reheater	•		•	•	•	•	•		•		•					
Evaporator	•			•	•	•		•	•	•						
Economizer	•			•	•	•		•	•	•	•					
Drum	•	•			•	•			•	•						
Piping	•	•	•	•	•	•			•	•	•					
Valves		•	•		•	•			•	•						
Fins, tubes	•	•	•	•	•	•	•				•	•	•	•	•	•
Liners, casing	•	•	•	•		•								•	•	•
Ducts	•	•		•		•								•	•	•
Dampers	•	•		•		•								•	•	•
Structurals						•								•	•	•
Stack					•	•								•	•	•

3. Cycling enhances the action of all damage mechanisms, listed here and keyed to the main HRSG sub-components

4. Steel support and trolley system had to be installed to slide reheat attemperator out from under the HRSG

ments,” *Bill Kitterman, SVI Bremco*
Slide deck, a photo journey of removing, repairing, and re-installing a hot reheat steam bypass attemperator, high pressure steam attemperator, and a reheat attemperator will disabuse you of any notion that the process is straightforward, mostly because of the cramped, tight areas these components are located within the HRSG block, original design materials selected (P91), support structures, and welding limitations (Fig 4).

Memorable quotes from the presentation (users and presenter): “OEM that built this unit did not believe in maintenance,” “there are so many issues, it’s almost beyond planning,” and “if you have P91 units, start stocking replacement material you can use based on your line sizes”

“Corrosion Under Insulation – What Lurks Below,” *Jordan Bartol, HRST*
If your HRSG has 20+ years operation (like many from the 1997-2003 CC boom years), these photos of corrosion under insulation (CUI) may cause you to immediately remove insulation and check the piping, especially in areas affected by exhaust gas dewpoint and ambient dewpoint (Fig 5). Examples of CUI covered are economizer drainpipes, feedwater piping, blowdown piping, LP evaporator riser, HP economizer vent, insulated stacks, and others. Cursory and advanced NDE inspection techniques are described, along with practical tips and modifications which can prevent or reduce risk of CUI.

“Attemperator Leak Detection to Prevent Steam Tube Damage,”
John Van Nostrand, Emerson/Flexim GmbH
Benefit from a clamp-on permanent ultrasonic flow measuring device, dubbed Fluxus, was so high in monitoring attemperator spray water leakage at one plant that the owner/operator added the devices to the reheat and high-pressure spray water lines in that plant, then applied them for flow measurement throughout the CCGT fleet (Fig 6). Technology is suitable for other applications, including natural gas flow, boiler blowdown, feedwater, cooling water, steam, and other fluids.

“Case Studies from CCGT High Energy Piping Reliability,”
Peter Jackson, Tetra Engineering
First slides here review maintenance planning and implementation associated with relevant guidelines for covered piping systems, including ASME B31.1 (2008 Addenda), EPRI Guideline 1018998 (2009), and ASME B31.1 Chapter VII (2024). Following slides cover case studies of (1) hanger condition assessment, (2) water hammer cracked cold reheat (CRH) pipe weld, (3) creep failure of HP bypass to CRH, (4) quench failures of HRSG reheater interstage DRH 90 deg elbows, (5) HP steam drain manifold failure by high-speed erosive wear, (6) fatigue failure of common hot reheat welded lateral, and (7) formed Tee design issues and early life creep failures.

5. Corrosion under insulation (CUI), which has forced many plants into an outage, is getting more attention with CCGT units over 20 years old

“IEEE C37.23-2015 Standard for Metal-Enclosed Bus,” *Mohsen Tarassoly, EBI*
Isolated phase bus and other bus systems (segregated, non-segregated) are among the only components without backups at a powerplant. When it fails, the plant is out of service. The referenced IEEE standard updates temperature, voltage, and current ratings; rated insulation levels; and short-circuit, momentary, and short-time withstand currents. Buses should be maintained during a scheduled shutdown, or at least every 18-24 months. Don’t rely on what you see; take advantage of EMI tests which can help identify (though not conclusively) problem areas.

“Top 5 SCR Performance Issues,”
Vaughn Watson, Vector Systems Inc
Catalyst is often not the culprit in SCR mal-performance. Differential pressure across the catalyst, catalyst bypass/plugging, poor ammonia distribution and reagent quality are other factors. Slides cover these topics with a focus on the ammonia injection grid (AIG) and the importance of component manufacturing on AIG performance. Company also supplies in-situ test grids for tuning and optimization.

“Generator Outage Management – What’s Your Contingency Plan?”
Jamie Clark, AGT Services Inc
Overriding message one: Get your unit’s baseline condition now! Message two: AGT (along with PSM) “has the capabilities and expertise to address virtually all OEM deficiencies.” The current availability of large-generator services for power plants is not comforting as the demand crunch (20+ year old units, other units close to their 2nd or even 3rd field rewind) converges with limited shop and field resources and specialists.

Slides offer a wealth of good material to plan inspection and repair outages, includ-

6. Ultrasonic flowmeter, clamped onto an attemperator spray water line, was able to detect leakage and avoid boiler tube damage. Device is suitable for challenging plant locations when existing flow detection isn’t working well

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ing expected schedules for major, minor, and mid-range outages, field rewinds (six months out), stator rewinds (one year out), and duration of common repair situations. Other slides cover scope document development (e.g., standard field and stator testing), robotic inspection (when, and when not, to use and why, with numerous photos), addressing OEM bulletins, and issues with brazed joints across the OEM offerings.

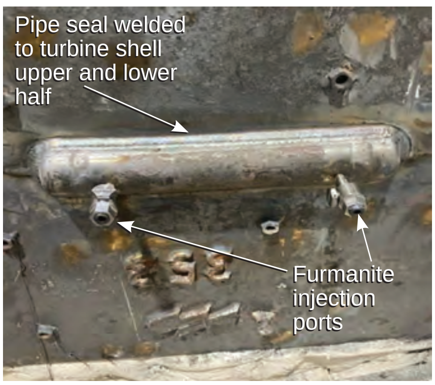
"Air Filtration and Extreme Weather," *Bob Reinhardt, Donaldson Filtration Solutions*

Slides in bulleted outline form cover F9 vs E class filtration; extreme weather events (snow and ice, wildfire smoke, extreme heat, and high humidity and coastal locations); and preventive maintenance steps, including pulse checks, filter installation, prefilter changeout, evap tuning, and hood treatments.

STUG™
STEAM TURBINE USERS GROUP

A spirited Roundtable discussion among users kicked off the conference. Some of the more salient topics and concerns include:

- Changing maintenance strategies to reflect cycling of baseload designed units.
- Frequency of inspecting l-p blades for erosion from low-load operation (several say once a year, one user inspects twice annually)
- Incorporating drones into inspection programs (they can help justify a full-scale inspection financially)
- Inexpensive ways to inspect without putting bodies into machines.
- When to deal with high hardness on journal bearings
- Frequency of testing for main-steam stop and control valves and balancing OEM, insurer, and owner/operator (O/O) recommendations/requirements



7. A length of 2-in. P22 sch XXS pipe (cut in half), with WP22 sch XXS caps, and Furmanite injected into the annular space, was seal-welded to the ST/G shell to mitigate a steam leak

- New demands by insurers after an overspeed event and best levels for overspeed tests
- Protective relays and logic changes for lube-oil DC pumps
- Unforeseen balance of plant (BOP) consequences from a GT uprate/upgrade, such as upgrading circ water pumps and steam turbine impacts such as HP/IP rotor and blade erosion

Three user presentations and some roundtable discussion time were devoted to HP/IP turbine issues with the D11 model. These slides are must-read for anyone considering their options for older D11s. Keep in mind that the ages of these units under discussion are not specified, so you should contact the presenters to gage applicability to your situation.

Other presentations focused on specific component condition, repairs, and replacements. Keep in mind that, while some of these presentations may appear to be "one-offs," the thought process and analytical methodologies can be universally applied when confronting similar issues.

"D11 Replacement Strategy" features a collaboration of three utilities, with 18 such turbines among them, to develop a scoping document and RFQ template.

Each user had its own reasons for developing such a strategy – some combination of shell cracking, thermal stress, creep deformation, diaphragm dishing, materials end-of-life, turbine train alignment difficulties, shell leakage, weak points from low-cycle fatigue, etc. The lead utility for the first replacement conducted deformation/distortion creep modeling using structured light scanning "at a fraction of the cost of laser scanning." First replacement, based on three bids received from four vendors queried, is scheduled for Fall 2027.

"D11 HIP Major Evolution x 4" is mostly one utility's pictorial journey as specialists sequentially evaluate four HP/IP turbines, witness the scope expand as more issues are found, and unearth surprises in the LP section. The "major planning takeaways" slide is the money shot, especially the words in bold, underlined red: "discoveries induce panic." A few of the more salient takeaways:

- Diaphragm refurbishments – request detailed scopes
- Boring bar - + 6 months reservation
- Rotor bow risks – review the data
- N2 packing area fits (deformation)
- LP inner casing will require bolt deformation, specifically at split

"Steam Turbine Shell Leak Repair" describes a home-grown solution to a D11 shell leak discovered through thermography on the right side of the IP section. Specialists fabricated a capped, ported piece of pipe cut axially, and seal-welded it to the turbine shell after heating the shell to 400F (Fig7).

Furmanite, a material specifically designed to seal high pressure leaks, was then injected by hydraulic pump into the ports to fill the space between the shell and the pipe, and the ports capped off. Afterwards, welds were inspected using MPE (magnetic particle).

"LP Inspections," titled "Steam Turbine Discovery" in the slide deck, includes photos and diagrams of indications found on numerous steam turbine models, but including D11 nested finger L0 removal and D11 shell indications. Though not a D11, the photos from a combined cycle steam turbine chemistry excursion event are particularly gruesome.

During the STUG conference initial "open forum & discussion," the topic of D11 rotor life came up and users noted that the OEM has no engineering supporting its recommendation to replace rotors for another 25 years of life. One user suggested buying a spare rotor or two for quick turnarounds. Another commented that "people are buying full spare components like valves and internals," and that "shop time to weld repair an L-0 wheel costs more than buying a whole new rotor."

Electrohydraulic control (EHC) systems, described by one user as a "the lifeblood of the ST/G," got also good airtime during the forum.

"EHC System Issues" (slides not available at publication) describes how a combination of OEM deficiencies and inattention from the plant and owner/operator led to failure of the HYDAC EHC (electrohydraulic control) skid just a few months after commissioning a CC facility in 2022. High particle counts and varnish issues were observed immediately. Numerous contributing factors are noted following the root cause analysis (RCA).

From the plant side, factors included enclosure doors broken since commissioning (plastic hinges were replaced with steel) and inadequately sealed control box panel, allowing water intrusion. Presenters acknowledged that the owner/operator accepted the plant this way.

From the vendor side, drying air flow was set too low, heating and cooling fan set point range was inadequate, and the pumps exhibited premature physical wear because they were not being lubricated sufficiently. The OEM had acknowledged failures on these pumps at other sites.

Pumps exhibited other problems, such as high axial tension. Replacement pumps, arriving after 25 weeks, failed. Spare pumps also failed. The HYDAC design was determined to be faulty. Even after installing a temperature control pump skid and blowers for cooling, the fluid was still "cooking." Both cooling circuits were needed to maintain fluid temperature.

It turned out that the two varnish pumps were essentially "fighting each other," and simultaneous operation is detrimental to varnish pump reliability. Now, the pumps operate independently of each other and are

able to maintain the fluid temperature range.

Later, a main steam stop valve, fitted with a cold weather "heat orifice feature" inside the control block, failed. Plant plugged the orifice, as it turned out to be detrimental to reliability.

Lessons learned: slight variations in skid location and ambient conditions can lead to significant performance degradation; and plant personnel need to pay attention to this equipment, be diligent about sampling and analysis and planned maintenance checks, and maintain adequate stock of M&S items, like filters.

"Electrohydraulic Systems," by an EPRI specialist, is a primer on EHC and includes refresher material on subsystem components, types of hydraulic fluids, deeper dive into phosphate ester fluids and degradation mechanisms, fluid handling component maladies and causes, recommendations for walkdowns/operator rounds, preventive maintenance and O&M best practices, phosphate ester sampling and testing, comprehensive system sensor plan, and other subjects all sourced from larger EPRI documents referenced at the end.

"D5 10-month Outage & Cracked LP Rotor." Desperate times call for desperate measures, or when you need peaking capacity, you'll go to any lengths not to permanently retire an ancient unit. This presentation is the saga, thankfully with a happy ending, of a 1961-vintage D5 ST/G LP rotor coupled to conventional gas boiler unit that suffered a 21-inch indication on the L-0 wheel at the fillet transition from shaft to rotor hub.

For six months in early 2023, vibrations at the T3, T4, and T5 bearings were increasing while the unit was progressively derated to compensate. When it became unbearable, an outage was taken, originally scheduled for two and a half months. The indication turned out to be a crack at least three inches deep.

Utility personnel searched their archives and found TIL931-3 from the early 1980s on wheel fillet machining recommendations for LP rotors with 26-in last stage blades. That document offered one option: procure, fabricate and weld a stub shaft in place of the last stage wheel (generator end).

Other options were to order a new LP rotor, repair the existing rotor, or find a salvageable replacement rotor. First two options had prohibitive schedules, and the plant did not have confidence in the repair option. Fortunately, the TIL documentation also included a list of affected units, sites possibly having decommissioned rotors. The plant managed to find a D5 rotor of appropriate length which was refurbished and fitted to the existing components (Fig 8).

Although the outage had to be extended by seven and half months, the unit is now able to deliver its full output to automatic generation control (AGC). Others who improbably find themselves in a similar situation may have to resort to options one through three: This may have been the last decommissioned D5 LP rotor available, at least in this length range.

"Siemens BB43 to GE HP/IP retrofit" covers the retrofit of a high-risk 1967-vintage (originally Westinghouse) ST/G with 370,000 operating hours with a fully bladed HP/IP rotor (with reaction blading design), HP inner casing, IP blade carrier, and IP packing heads (N1-N3) fabricated by GE in Poland. An HP/IP assessment showed an unacceptable level of rotor bowing (runout), creep/embrittlement, and casing cracks.

The slides offer dozens of detailed diagrams and photos of scope work items, field modifications, component drawings, module casting, pre-assembly, major component removal and install, fit-up, and final assembly. A list of lessons learned includes these:

- Have the shop put the module together (pre-assembly) before shipping to the site
- Negotiate to have field welding performed at the shop when applicable
- Have a steam turbine engineer assess parts prior to the outage
- Manufacture inserts early in the outage; it took five tops on/tops off iterations to complete the installation and jack bolt holes were damaged in the process
- Make sure special tooling is accounted for and inspected
- Have sealing OEM come to site to measure hook fits thickness, diameters, out of roundness, etc
- Include in base scope disposal of old components
- Insist that the OEM provide detailed assembly iterations before the outage to fine-tune the schedule
- Fabricate inner and outer gland packing to fit; do not rely on part numbers

"Steam Turbine Crossover Assembly Tie Rod Failures" on an ST/G in a 1376-MW 3x1 CC facility were experienced after only 27 starts. While the failure was likely due to fatigue, the cause was not conclusively identified. Testing showed that the AISI 4140 steel material was compositionally verified and its tensile strength within range.

Also discovered was that the tie rod shafts had cut, not rolled, threads with relatively rough machining marks. This could have contributed to the failure but only as a secondary factor. It turns out that the 2nd and 3rd harmonics of the tie rods are very close to 60 Hz. Also discovered was that a similar unit at another site featured lateral supports.

Proposed solutions include: increase rod diameter, change rod material, seek better surface finish in threads, change to rolled threads, add lateral supports, and/or use tapered threads in the load-bearing nuts.

"A10 In-situ Bull Gear Replacement" includes this on slide 2: "Instead of thinking outside the box, throw out the box." That perks your ears up when dealing with complex engineered systems in the field. At this 1228-MW CC with four A10 ST/Gs, premature wear of a turning gear ring (bull gear) was caused by inadequate oil flow, and the gear had to be replaced. The plant procured a new bull gear (with extra stock) and devised what is thought to be a never-before-tried method of removing the old one. Since the gear is friction-fit, expanding it with heat would allow it to be removed in the field, leaving the HP shell/rotor untouched, while uncoupling the generator field, sliding it six inches with a yolk-anvil, and placing it on skid pans. Differential expansion ratio calculations showed that the shaft would not be adversely affected by the necessary heat. Heating the gear to 450F with heating elements installed on the gear with belt-type sling, and insulation to protect the shaft, allowed the ring to come off. You'll have to check out the slides to see how the plant solved an emergent problem when the front standard (part of the speed control governor and trip system) interfered with full ring removal by approximately two inches.

"SCC in an LP Turbine (Present and Future Impacts)" is a cautionary tale about what happens when you postpone addressing a chemistry excursion because the unit could soon be scheduled for retirement. In May 2020, a 740-MW ST/G (part of a coal-fired unit) experienced a 13-day operating period with elevated sodium in the steam, with subsequent 1% loss of megawatts from the HP and IP sections. However, the greater concern was the progressive impact from stress corrosion cracking (SCC) in the LP section.

The utility's services team evaluated options and decided that deferring all cleaning and SCC-related inspections until a planned major outage in 2025 would be best based on technical and business risk. However, L-0 and L-1 blades were pre-ordered as a contingency, since this unit had become the highest risk in the utility's fleet because of the SCC.

The balance of the slides review the findings from a spring 2024 outage inspection, and subsequent immediate and longer-term tactics to address the SCC damage and general LP maintenance. Planners are now

8. Salvageable D5 LP rotor was found by combing through a list of units affected by a TIL issued in 1981. Rotor was then repaired and refurbished and installed in a 1961-vintage D5 ST/G which suffered a significant crack of the L-0 wheel at the fillet transition from shaft to rotor hub

considering extending the unit's retirement date for another 20 years. Sage advice: Do not neglect older fossil units on the assumption of imminent retirement. Consider this observation as well: Lots of plants are taking big risks by not having on-site chemistry specialists.

"Lack of Skilled Labor" points out some alarming workforce trends impacting the ability of the power industry to attract necessary expertise, including the COVID-related exodus of skilled labor, baby boomer retirements, decline in apprenticeships, appeal of digital- and computer-related positions, disparities between cost of living and salaries in key regions, high cost of earning engineering degrees, and changes in 6-12 curriculum eliminating classes nurturing mechanical skills (e.g., shop).

Five recommendations for mitigating the skilled labor shortage are: bring back apprenticeship programs, reimburse tuition and training expenses, attend jobs fairs, hire employees direct from high school, and retain skilled and qualified personnel.

STUG VENDOR PRESENTATIONS

"Safety Differently: A Story About How Your Organization Could Learn Differently," *Matt Barnes, MD&A*

Message here is that team performance improves when you work through a safety event with positives instead of the absence of negatives. Positives include the capacity to be successful under varying conditions, the ethical responsibility to the organization which has to handle messy, risky work, and making sure the people perceived to be part of the problem (those involved in the safety mishap) become part of the solution.

"MD&A Parts – Guardian™ and Vortex Shedder™ Design, Installation Process, Benefits," *Jacques Amyot, MD&A*

Title refers to parts for the ST/G steam sealing (packing) rings installed in over 300 units of all OEMs which are "proven to increase efficiency by 1.5-4.5%." Slides cover steam sealing basics (with excellent diagrams), product design descriptions, reverse engineering measurements, installation steps, and case studies (Fig 9).

"Steam Turbine Valves,"
Dean Casey, MD&A

Improperly functioning valves can and have led to catastrophic ST/G failures, begins this slide deck, which then reviews virtually all aspects of valve and component outage planning, inspection, issues and repairs (including slides specific to common ST/G models), reassembly, shipping, and final reports from the service vendor. Bonus topics include integral strainer basket replacement, control valve seat replacements, and indications in, and refurbishments of, steam chests.

"Alstom HP Inner Block Shop Inspection and Repair,"
Satish Amand, Power Services Group

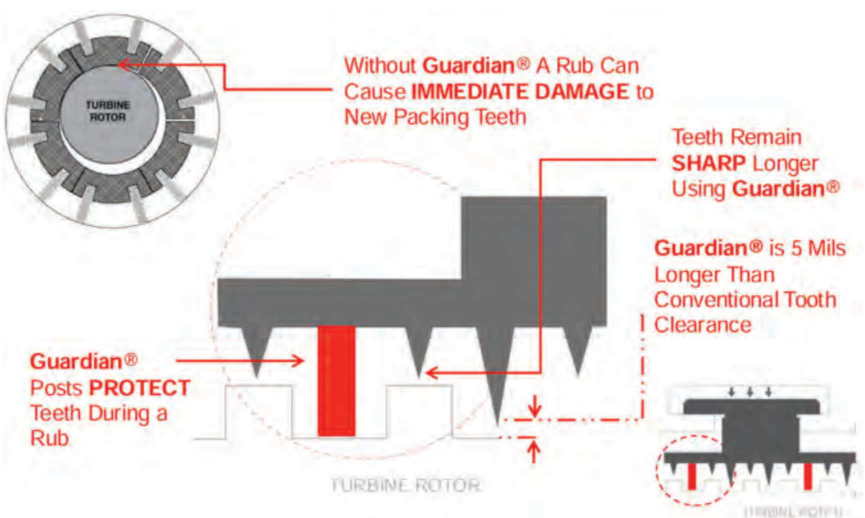
Slides cover inspection and findings, disassembly and assembly, shop repair base scope items, engineering evaluations and repair processes, and R1-R4 blade replacements not in the original scope for a 190-MW 2001-vintage ST/G. Company's Gainesville, FL, facility is being expanded to handle steam path component repairs.

"Turbine Outage, Lessons Learned, and Maintenance Case Studies,"
Scott Cavendish, Independent Turbine Consulting LLC (also presented in the CCUG)

The first section summarizes general observations over multiple outages worth paying attention to. Among them:

- Experience deficit is leading to technical errors in the field
- Little standardization exists for lockout tagout (LOTO) from site to site, for example great variation on "temporary" lifts for systems such as lube and lift oil
- Outages are often longer than planned, being planned at the last minute, and lack contingency options
- Lighting is often inadequate where work needs to be conducted
- Lack of attention to the low-hanging fruit of logistics – toilets, office space, scaffolding, fork lifts, tooling rentals, welding gases, etc – often leads to major delays

The second section covers the following case histories of field problems and solutions: bobbing V1 valves in the mechanical hydraulic controls (MHC) of a 1961-vintage D5 ST/G, recovery from a Front Standard fire, high generator vibration after major inspection (two separate cases), and lube oil and varnish buildup.



9. Upgraded packing ring is 5 mm longer than conventional tooth clearance, with posts to protect teeth during a rub

The GUG kickoff roundtable discussion focused on a few specific topics which offer food for thought for those not in attendance. Among them:

- Can a flux probe (FP) detect pitting of the retaining rings? One user noted that FP readings showed nothing prior to an outage but extensive pitting on retaining ring inner diameter was discovered. Other users asked what kind of pitting – dissimilar metal, chemical, mechanical? Perhaps the FB is effective for severe pitting, not necessarily general pitting.
- The question, how many have implemented TIL2417 (generator stator end winding blocking modification), was posed to those with 324 type generators. Half a dozen or so (of 30+ in the room) responded affirmatively. One attendee lamented that even with the mod, you can still have failures.
- Can you safely operate with a broken or non-functional flux probe? A user responded that generally, answer is yes, but should make sure the probe is grounded to prevent shock.
- Do you perform field pulls or robotic inspections during generator maintenance? Eight hands went up for robotics, several do both.
- Any experience with the OEM's Harmonic Noise Index (HNI) test. One user performed HNI for five 7F machines and found high levels but noted that it indicates long-term degradation mechanisms which "won't take your machine down tomorrow." Another said it helps determine which belly bands are loose so you can figure out which manways to crawl in to inspect.

"Cold weather preparedness" was a popular topic based on the size of the audience. Presenter from the Midwest Reliabili-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ty Organization (MRO) reviewed five winter storms with catastrophic impacts on the bulk electric system over the last fifteen or so years. Most of the subsequent material then reviews the MRO winterization program, a joint voluntary effort a plant may embark on to address risks not covered by the NERC Reliability Standards.

Those interested should review the NERC Reliability Guideline: Generator Unit Winter Weather Readiness Current Industry Practices – Version 4. The list of cold weather equipment failures suggests, at a minimum, where users should place priority when temperatures begin to drop.

Presenter notes that the program does not address the NERC cold weather reliability standards but will dovetail with them. Some specific notes: the generator stator has anti-condensate heaters but they occasionally fail, snow and ice can get into the air system of an air-cooled machine, and far north plants can experience brazzle ice on the air intake.

"Generator Faults and Concerns" covers the failure of high voltage bushings (HVB) in a GT generator serving a 2x1 CCGT after two unit trips less than a year apart, the first occurring just after a major outage, resulting in four top stator bars (six o'clock position) being removed and one replaced. During the prior outage, the stator was rewedged, a DC hi-pot and core loop tests were conducted, and no other major issues found. After each trip, the generator had to be inspected, tested, and disassembled. The HVB failure was discovered after the second trip.

Root cause proved to be oil infiltrating into the bushing (five gallons found in each HVB and removed) and blocking the flow of ventilation air. This caused connection points to heat up and burn the insulation in the HVB. Major consequence was that a full stator rewind scheduled for 2026 was completed several years earlier and some laminations were replaced, along with the outside space block (OSSB). Slides include excellent photos of damaged components and concerns discovered with other components, including the collector studs and OSSB.

A word of caution for others who might experience similar issues: "HVBs are not easily replaced."

"Generator core and parallel ring exchange" shares the investigation into an in-service failure of a TLRI generator and how the machine was returned to service. After listing the event indications and performing electrical tests, the plant's major finding was phase-to-phase (A phase) catastrophic failure of two bottom coils with the TE winding circuit at the six o'clock position and one top coil in the 5:30 position (C phase). Numerous closeup photos illustrate the damage.

Repair plan includes a core and parallel ring swap with a rotor exchange by the OEM using the existing frame. The available spare stator was not compatible with the plant's operating configuration, so the parallel ring assembly had to be modified, and the plant had to purchase a used rotor because the OEM's spare was configured for brushless excitation (vs static). Rest of the slides are a photo journey through implementing the plan.

"Rotor cooling holes blockage" describes the odyssey of a generator attached to a 500 MW unit which failed in 2009 and 2011 from ground faults and was swapped for a used unit upgraded and modified as necessary. Shortly after entering service, the swapped unit experienced hot spots on the back of the core and rotor filler migration blocking rotor cooling passages. The situation was monitored for many years until high vibrations were noted as the reactive load increases in 2022. Balance of the slides details a "rotor set screw" repair option in lieu of a new rotor or shop or site rewind. Only the EE retaining ring needed to be removed to do this repair.

"GE324 phase strap failure" concerns a generator differential trip which occurred on a GE324 unit (integrated gasification CC), also known as the H53, before TIL2417 R1 (issued in 2023) could be implemented. During an MI in 2020, the plant implemented TIL1965 ("Radiographic NDE of Phase Straps"). TIL1965 applies to all leads-down, 60-Hz models built before 2018 with a rating of 325 MVA or higher. TIL2417 R1 applies to all leads-down, 60-Hz models built before 2018 regardless of rating.

Three of four lockout relays activated while the unit was operating normally at 110 MW load. Review of the event files showed that current magnitude reached 109,000 MVA and the failure occurred between the B and C phases. After subsequent isolation of the generator, purging, and visual inspection, damaged phase straps and stator contamination were discovered. Numerous photos in the slides show the extent of both.

The failure mode is described as a combination of thermal and mechanical dynamics between connection rings, phase straps, phase bars, and associated blocking which resulted in de-bonding of the strap blocks and ties. Over time, the blocks and ties gradually wore through the insulation until the failure occurred.

O/O elected to repair and clean (3-week outage) the stator and implement 2417 and rewind the rotor because of heavy contamination and low IR test results. Three other units of this model were identified in the O/O's fleet, with two exhibiting significant dusting after inspection. 2417 was implemented on these units during planned outages, along with a 10-start re-inspection interval for all affected units.

The good news is that phase straps can be borescope-inspected from the bushing box.

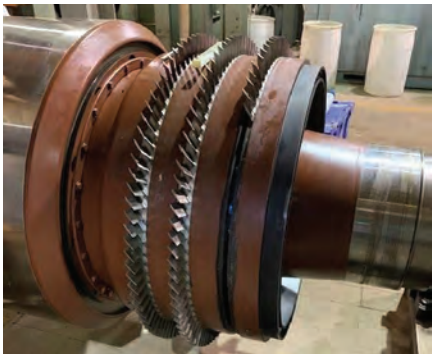
"Managing through a generator rotor ground indication and rewind" could be retitled four and a half decades in the odyssey of a generator in peaking service on a conventional fossil unit. The 500-MVA Allis Chalmers H2 and water-cooled unit entered service in October 1977, experienced a forced outage of unknown cause in 1978, and had 1000 starts under its belt by July 1985, and 2000 starts by June 1994. The rotor was rewound in 1998, and again in 2009.

The unit's first ground alarm occurred in early May 2023 and field ground alarms began to initiate sporadically into late June. Because the consequences of a second ground can be catastrophic, the presenter asks two critical questions: What is an appropriate value to alarm and what is an appropriate value to trip or remove the unit from service?

Alarms became more consistent, and the plant began planning disassembly for repairs in the fall. It took fifteen days to get the rotor on a truck to the shop, where multiple issues were discovered, including heavy oil contamination, retaining ring liner crack, slot liner patch from the 2009 rewind, turn insulation not properly applied, and coil cracking. Next step was a rewind.

You'll have to check out the slides to learn the challenges overcome during the rewind, subsequent overspeed test, and rotor rebalancing (Fig 10). Once the rotor appeared ready for service, vibration began to creep up three months into operation. One unique finding during the investigation: a snapped structural H-brace, apparently added two years after COD, with loose mounting bolts on the exciter outboard bearing which was found loose and unloaded in its spherical seat.

"Generator FME – importance and historical consequences" will make sure you don't become complacent about foreign material exclusion (FME), or simply, stuff left inside a generator that doesn't belong there. There's a bit of humor in the slides involving lanyards for your safety glasses you won't want to miss, if numerous examples of foreign objects found inside and their consequences aren't enough. FME is responsible for major generator damage every few years and minor damage several times a year, the presenter notes.



10. Blower blades removal and replacement, several damaged, was one of multiple challenges during the most recent rewind of a 1977-vintage Allis Chalmers 500-MVA generator

How do you ensure FME from your unit? The last slide is the money shot, listing obvious but also obviously overlooked steps like accounting for all material taken into the workspace and detailed inspection by experienced personnel before the access point is closed. Practically, you can: (1) create a barrier at open areas, (2) secure with FME tape or hard barrier with a log book for components taken in and out (depends on the honor system, though), and (3) a full-time gate attendant (not perfect but effective).

"TLRI Generator Rotor Failures" reviews two events – unit behavior and operator notices, findings and testing, and repairs - suffered at a site with this model generator. The first is a J-strap failure, the second a glycol cooler leak-related failure. Numerous photos accompany the narrative.

"GE 324 Generator Rewind Case Study" covers the challenges faced after a 263 MVA unit tripped on A phase differential running at 110 MW (unit rated at 197 MW). Subsequent O/O and OEM electrical tests were inconclusive. Three months before, the ST/G unit went through a three-month overhaul outage under an LTSA with the OEM at which time it passed all electrical tests but failed a bump test when the plant was looking into the modifications recommended under TIL2417 R1.

Management decided not to perform the mods for reasons listed in the slides, the most notable being a generator field replacement scheduled for 2027. You can guess what happened when the last slide recommends to the audience that they make the end winding modifications under 2417.

The other important recommendation is to check current transmitter wiring. This site found worn insulation and a ground fault where two wires crossed and were touching (Fig 11). Two similar instances of crossed CT wiring were found on other units.

"Troubleshooting generator vibration" is about as concise a guide to the subject as you're likely to find written for plant personnel (not vibration specialists) and available for free. The material presented is relevant for "about 75% of the vibration issues you'll typically see." This is a "must view" if you're training a plant engineer or technician in vibration analysis.

One of the first slides is "know your tools." A large table (vibration issues in rows, measured parameters and characteristics in columns) offers guidelines to link different issues with their common data patterns and determine what is commonly seen with that issue, and what is not (Fig 12).

GUG VENDOR PRESENTATIONS

"Generator Protection Theory,"
Doug Weisz, Hubbell Power Systems/ Beckwith Electric

Among the features of the 200+ slides supporting this four-hour training tutorial is a discussion of generator protection in the context of the NERC standards which were developed as a response to the US blackout of 2003, largest in North American history. These standards are intended to keep units online, if possible, without damaging equipment so they are available to support the system and prevent the blackout from spreading.

Otherwise, the list of topics in the table of contents alone is daunting unless you are an electrical engineer or a generator specialist. Perhaps more than anything, the presentation indicates the value one gets from the modest attendance fee for these parallel user group conferences.

"Demystifying Epoxy Resin Systems in Generator applications,"
Chris Klein, Astro Chemical

Topics covered include epoxy chemistry review, overview of applications in large generators, and frequently asked questions which don't necessarily have obvious answers. For example, under "can I use this resin for that application" is the advice not to mix epoxies and polyesters but also that every supplier has a "jack of all trades" product which can be used in multiple applications. Tying and saturating resins make for good adhesives and protective coatings.

"Generator Stator Condition Assessments and Decision Making,"
Jamie Clark, AGT Services

Big headline from this presentation is that a huge number of stators are reaching the end of their design lives, there are more unplanned stator rewinds than ever, large O/Os are planning/budgeting fleetwide stator and field rewinds over the next five years, and the shop and field service resources to handle all this isn't increasing.

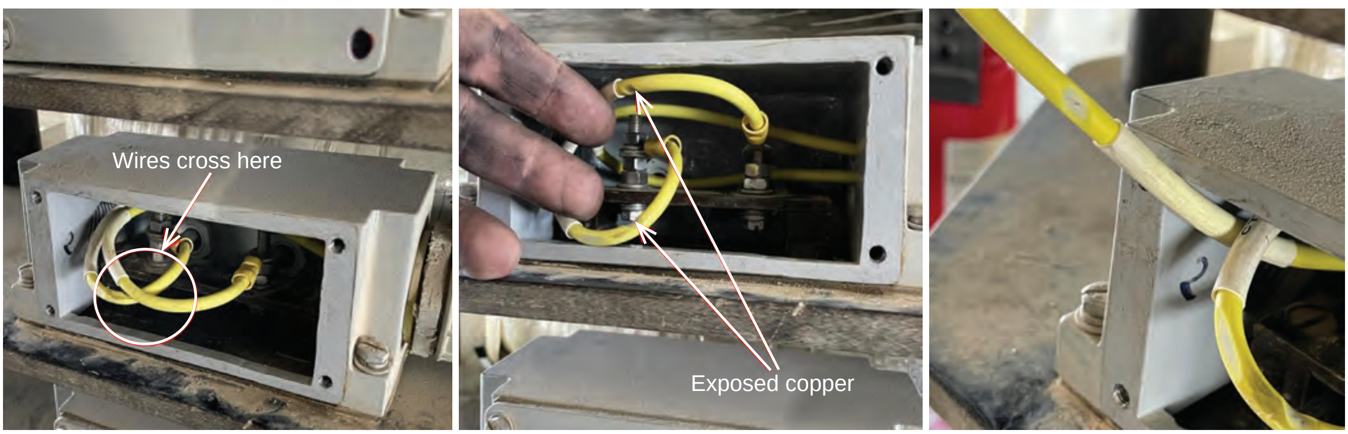
The more specific headline items from this presentation are (1) bolted joint integrity (and failure of the brazed joints) is a "big issue" but can be detected with on-line monitoring, (2) all OEMs have bulletins out on end winding issues, (3) global core looseness can be a problem with newer GE units, (4) loss of core compression will lead to core winding faults, (5) OEM upgrades often ignore generator constraints or operating history, (6) every unit should have a flux probe installed and a flux probe evaluation should be conducted at least once a year, especially if you have changed operating profiles, (7) the OEM should do a borescope inspection under the retaining rings during a minor, and (7) it takes 4-6 months to get a new set of windings.

"Electromagnetic Interference Monitoring Case Studies," *Kent Smith, Cutsforth*

To illustrate the value of EMI monitoring, plant components and situations under scrutiny here include generator hydrogen analyzers and water accumulation, circulating water pump motors, excitation power rectifier, loose wedges in water cooled generators, isophase bus, bearing electrolysis, isophase bus link, and turbine bearing.

"Generator Overheating Detection and Response with a GCM-X,"
Christopher Breslin, Environment One

The GCM-X (generator core monitor) detects sub-micron particles emitted when epoxy paint and/or core laminating materials overheat and thermally decompose. Device should be a key component for monitoring your hydrogen (or air) coolant auxiliary



11. Ground fault and worn insulation were found where two CT wires crossed and touched (left and middle). A similar situation was found in another unit (right)

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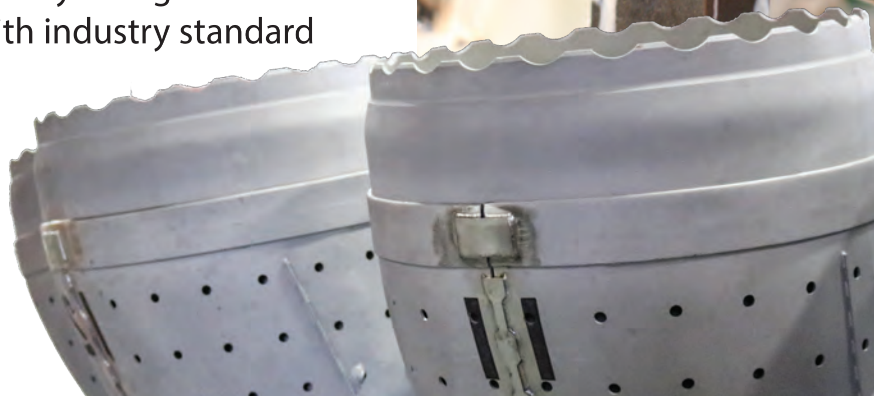

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12. Diagnostic tools for troubleshooting vibration issues include common unit data like load and bearing temperatures, but also data obtained from hand-held vibration meters with FFT (Fast Fourier Transform), digital devices (phone, tablet) with app store connectivity, and motion amplification cameras

equipment, especially because the fleet is aging, workers are younger with less training, periods between outages are extended, and units are heavily cycled. Slides review data trends in several case studies and ways to better understand your GCM system and how to maintain it.

"Brushless Excitation, Parallel vs Series," *Jacques Leger, WEG(EM)*

Slides focus on redundant protection schemes found on generator rotating rectifier wheels with series or parallel diode arrangements, common failure modes, testing and troubleshooting, and AVR fault reaction and options for diode fault detection through the AVR.

"Exercising Your System (The Importance of Testing and Cycling Your Electrical System,"
Nathaniel Smith, TEMs

Although NERC PRC-005 says cycle your electrical equipment, most plants only do this for the mandated items which interface with the bulk electric system. This presentation suggests that you cycle all your electrical systems every opportunity you get, including protection and lockout relays, AC sensing devices (current and pressure transmitters), and breakers. Maintenance recommendations are included.

"Diagnosing and Correcting Exciter Cab Resonance,"
Danny Besmer, WEG(EM)

Slides convey the lessons learned and troubleshooting methods while resolving vibration issues attributed to natural frequency resonance found on 7EA generators. In particular, design and mounting features of an EM exciter have been found to correct resonance induced vibration characteristic of Kato exciters in some projects (Fig 13).

"Safety Differently," *Matt Barnes, MD&A*

See same entry in STUG vendor presentation section.

"324 Generator Failure Discoveries, Concerns, and Repair,"
Howard Moudy, NEC

Subject of these slides is the investigation, discoveries, and repair of a failure resulting from a T2-T5 ground fault in a 321 KVA generator a few months after an outage that included a full stator rewedge and DC Hi-Pot. Root cause proved to be compromised strand insulation of the top bar #63 which progressively shorted to adjacent strands, causing severe overheating and ground wall deterioration. The replacement strand features double serving crosshatched Dacron glass with no exposed conductor, unlike the original (Fig 14). Presenter recommends that upgraded insulation be part of future rewinds.

13. Proper tuning of the mounting bracket and addition of an expansion joint with the EM exciter, right, has been shown to correct resonance-induced vibration seen with Kato exciter units on 7EAs

"Generator Field Issues Which May Extend Your Outage,"
Jamie Clark, AGT Services

General categories covered are slot component migration, distance blocking movement, turn insulation migration, copper distortion, braze design/failure, collector systems, and H2 seal oil systems. Slides are replete with examples (and photos) of defects in both OEM and third-party rewind work.

"Damaged Main Lead Field Copper,"
James Joyce, MD&A

After explaining and illustrating the purpose of the main leads, leaf vs solid plate designs, radial/rotational failures, and electrical failures, slides proceed through improved main lead design features and support modifications, along with several photos of the installation process.

"Stator End Winding Concerns with Newer Vintage Generators,"
Howard Moudy, NEC

Since 2013, there have been at least 10 failures of phase straps in 324 model generators, and three TILs issued to try to mitigate the problem. The long-term solution is to coordinate all end winding components to eliminate the accumulation of stress which leads to deterioration and failure. Attention to end windings is critical to generator maintenance.

End winding movement from normal vibration levels should be addressed by inspection and monitoring, and repair if necessary. Movement from vibration due to resonance requires detuning and retesting. Movement from thermal contraction and expansion of the end winding itself (caused by unit cycling) is becoming more of a problem and requires more diligent monitoring and implementing long-term solutions, such as specialized engineering approaches offered by NEC.

"Two 2024 EPRI Projects,"
Bill Moore, EPRI

Slides offer deep insight (though not definitive answers) to the questions (1) Do we rewind the generator now, later, or run to failure; and (2) is a global vacuum pressure impregnated (GVPI) generator a better investment than single bar VPI and resin-rich designs? Regarding (1), insight takes the form of visual observations (supported by

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BENEFITS OF EMI MONITORING

- Monitors and trends failures on critical assets such as Isophase Bus, Generators, Switchgears, Transformers, and more
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- Lower costs compared to third-party services
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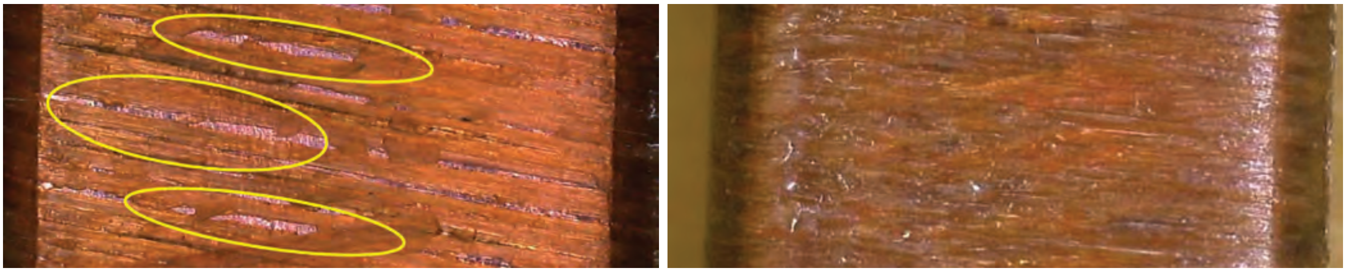

14. Original magnified stator bar strand, left, pinpoints weaknesses compared to upgraded replacement

photos) indicating a rewind is necessary now, testing results that suggest the same, and common reasons for stator and rotor rewinds based on an industry survey.

Results from surveys returned by fifteen utilities representing 500 GVPI units are included. While the design certainly has advantages, two areas of concern highlighted are that 64% of respondents report at least one in-service failure or developing failure mechanism, and GVPI stators are "notoriously difficult to rewind." 27% of respondents would not choose a GVPI unit again in the near future.

"Controls Items for Consideration" collects round-robin thoughts and ideas on Mark series controls from one specialist representing one of the largest owner/operators in the nation. Topics include logic for verifying valve functionality prior to unit operation, end of support for HMI (human-machine interface) Windows Server 2012 R2 Operating System and network switches, simulators, lube oil system tank volume, dual hydrogen control panel enhancements, tuning tool, and password control for cybersecurity. Most of the slides are screen shots likely most meaningful to control system experts.

Regarding the HMI, sites were notified of the support termination with little time to react. Rather than opt for the OEM's proposed solution, with its protracted procure and install schedule, one site purchased licenses from the OEM, server boxes from Dell, and configured the system themselves, cutting the lead time by 32 months and the cost by an order of magnitude. Similar cost and schedule results were achieved by purchasing and configuring network switches directly from the supplier and building simulators in-house.

Long term advantage of this approach is acquiring and retaining the site/owner knowledge necessary to maintain and troubleshoot these components going forward.

"Third-Party Controls Upgrade" is an in-depth project recap outlining a successful multi-vendor controls modernization effort at a U.S. combined-cycle plant. The presentation highlights how a carefully planned and collaboratively executed upgrade delivered new turbine controls, excitation system enhancements, and static starter integration—all without relying on OEM packages.

Project scope included:

- Turbine controls replacement with ABB's modern platform
- Excitation system upgrades integrating AP4's DFE solution for a Basler system
- Static starter modernization incorporating TMEIC LCI with AP4 crossover interface

The implementation team emphasized cross-disciplinary planning as a cornerstone of success. This included:

- Full scope walkdowns and risk identification prior to outage
- Detailed drawing reviews, factory acceptance testing (FAT), and loop/commissioning validations
- Network documentation and secure access protocols
- Explicit division-of-responsibility mapping across turbine, excitation, and starter systems

Of note, the PSM AutoTune system was already in place, providing a performance foundation during the GTOP 3.0 installation. This continuity allowed the project team to focus more on controls integration and less on combustion optimization.

Key takeaways for others considering third-party integration projects:

- Advance planning and communication mitigate downstream surprises
- Define handoff points and responsibilities clearly between controls and subsystem vendors
- Secure, documented networks with reliable remote access are non-negotiable
- Quality assurance steps (FAT, cold commissioning, loop checks) must be rigidly followed

The real value to anyone embarking on a similar effort is in accessing the full slide deck for screen captures of operator interfaces, system layouts, and vendor-specific integration steps.

"Generator Basics" is a primer session demystifies the generator by returning to its physical and magnetic principles, offering a visual and conceptual tour of how power is made—ideal for technicians, engineers in training, and even seasoned O&M staff seeking a refresher. The slides are rich in illustrations and analogies to reinforce understanding.

Core concepts covered:

- Magnetic flux and induced voltage
- Electromagnetic rotor construction
- Stator and winding design
- Cooling considerations

The presentation closes with a cautionary slide of a damaged generator, underscoring what can go wrong when excitation or synchronization are mishandled, a fitting reminder that even fundamental components deserve daily diligence.

"Exciter Fundamentals" is a valuable follow-on from the primer above, offering insight into generator control. Excitation systems may not be front-of-mind during day-to-day plant operations, but they are critical to stable generator output and grid compliance.

This fundamentals refresher, presented by a senior controls specialist, provides a compact yet thorough walkthrough of exciter types, core components, and practical O&M considerations—especially valuable for engineers newer to generator control systems or those facing legacy system upgrades.

The presentation begins with a simplified definition: Exciters are systems that supply the DC field current to the synchronous generator's rotor. It then explores how excitation impacts generator performance with particular attention to voltage regulation, VAR support, and system stability before breaking down the two primary exciter types:

- Static exciters, where power for field excitation is drawn from the generator terminals or auxiliary supply and passed through a controlled rectifier bridge
- Brushless exciters, which eliminate sliding electrical contacts by using a rotating exciter mounted on the same shaft as the generator, coupled with a rotating rectifier assembly

Supporting slides offer clear block diagrams and visual schematics of key components such as automatic voltage regulators (AVRs), power potential transformers (PPTs), field breakers, and rectifier bridges. The role of the AVR, the brain of the exciter, is emphasized in terms of keeping terminal voltage within limits under changing loads.

The presentation also addresses field flashing for initiating excitation when residual magnetism is low, power system stabilizers

(PSS) for damping oscillations and maintaining synchronism, and alarm/protection strategies for overvoltage, undervoltage, and loss of excitation.

Many slides include system diagrams and wiring visuals, best interpreted with reference to the full downloadable deck. Plants considering digital excitation upgrades or troubleshooting AVR behavior will find this overview a helpful baseline for internal discussions and vendor interactions.

PPCUG VENDOR PRESENTATIONS

"Mind the Gap-OT Security,"
John Downing, AP4 Group

Presentation first assesses recent global attacks on power grids, grid intrusions, and ransomware attacks; then reviews OT security challenges for legacy systems and proprietary protocols and standards, including regulatory compliance, emerging threats, and resource constraints; and finally offers generic best practices to counter and reduce cyber threats.

"Understanding Combustion DLN Tuning," *John Downing, AP4 Group*

First few slides remind the viewer how much more complex a dry low (DLN) NOx combustor is compared to a standard diffusion burner with water or steam injection, then covers some basics like NOx and CO emissions production, the temperature control curve as it relates to load cycling, tuning and autotuning, and importance of combustion dynamics.

"Understanding Gas Turbine Controls and Protection,"
John Downing, AP4 Group

This is the type of slide deck that validates for chemical and mechanical engineers why they stayed away from electrical engineering, computer science, and control system design. Joking aside, anyone needing a primer in GT controls will benefit from this deck, which cover HMI, controllers, I/O, sensors and instruments, final control devices (e.g., valves), software, control parameters, permissives, runbacks and trips, protection and monitoring, excitation, and cybersecurity.

Notable slides include network topology, ladder, and function block diagrams; the "secret" control blocks, and the "view from an air molecule" as to what happens as it proceeds through the centerline of the GT.

One session during the PPCUG GE Day is worth noting, an update on fleet controls issues since last year and associated TILs. As the presentations are not available at the Power Users site, and the language and acronyms used by the controls folks may not be familiar to non-control engineers and techs, listed here are the referenced documents and/or topics discussed:

- TIL 2441-R1 and GEK 1163– Lower Exciter overcurrent limit and arc flashover
- PSSB 20231014A – Starting motor torque converter fails to reach purge speed
- TIL2500 – License ST application corruption (March 2024)
- UCSx Controller unexpected reboot and inability to boot – one user mentioned two reboots caused by this, another mentioned seven reboots, and a third mentioned 15 caused by this issue
- GEH 6808 – redundancy checks in Control ST Software Suite
- TIL2290 – addresses bit error due to corrupt NAND flash failure to boot
- TIL2517 – Control server maintenance guidelines addressing cache disk degradation

Closing reminder. End users registered at www.powerusers.org are encouraged to download the full slide decks from the 2024 conference and put the shared experience and lessons learned to immediate use. The material spans everything from outage planning and controls upgrades to generator rewinds and cold-weather prep—practical, field-tested guidance that speaks directly to today's plant challenges. And if you're not already planning to attend the 2025 Combined Conference, set for August 25–28 in Washington DC, now's the time. Few events offer as much actionable content, peer exchange, and expert access in one place. CCJ

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Our proprietary method reaches 95% of the heat transfer surfaces, lowering back pressure, increasing efficiency, and improving power output.

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PIC's cleaning requires minimal involvement from plant staff and significantly reduces downtime compared to other methods, allowing for more operational hours.

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- Safe, easy cleanup with no damage to pressure parts.
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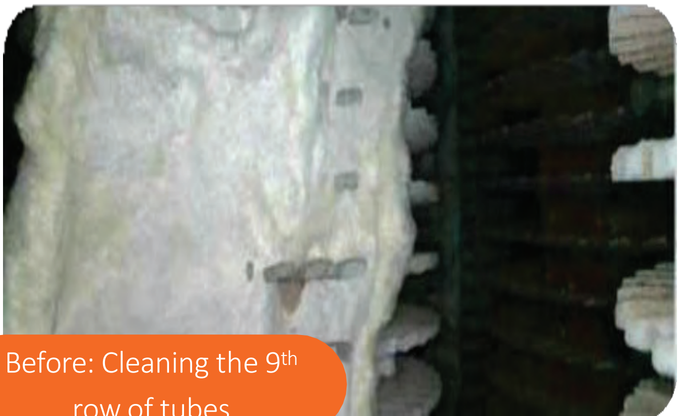

Before: Cleaning the 9th row of tubes

After: Cleaning the 9th row of tubes

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ABHUG

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The Australasian Boiler and HRSG Users Group Conference and Workshops (ABHUG 24) was held December 3-5, 2024, in Brisbane, Queensland, Australia. ABHUG is supported by the International Association for the Properties of Water and Steam (IAPWS) together with the local National Committees in Australia (AUSAPWS) and New Zealand (NZAPWS). This annual event is held in association with the European HRSG Forum and the HRSG Forum (US). Beginning in 2025, this collective will be joined by HRSG Forum América Latina, September 23-25, in São Paulo, Brazil (www.hrsgamericalatina.com).

The Brisbane event, organized by Mecca Concepts Pty Ltd, Australia, was co-chaired by Barry Dooley (Structural Integrity, UK) and Bob Anderson (Competitive Power Resources, US) and sponsored by HRL, Swan Analytical Instruments, and TLG Engineering. Combined Cycle Journal is the media partner.

ABHUG 24 attracted 90 participants from Australia, New Zealand, Canada, UK, Germany, and US. There were 26 prepared presentations.

All HRSG events are designed for users to communicate openly with each other, key component suppliers, consultants and international experts. Exhibitors are also invited and in 2024 delegates were joined by experts from Duff and Macintosh/Sentry, Flotech Controls, HMA Instrumentation, Intertek, Precision Iceblast Corporation, RTR, and Swan Analytical Instruments.

The first Australasian HRSG event was held in 2009.

Below are selected highlights from 2024.

THERMAL TRANSIENTS

Bob Anderson, Competitive Power Resources, opened the discussions with his in-depth, informative and global *Update and statistics on HRSG thermal transients*. Detailed insights into operational issues with attemperators, condensate, superheater/reheater drain management and steam turbine bypass operation are always a highlight of these conferences. Anderson's research pinpoints common problems and areas needing improvement based on international data.

This update is based on 70 surveys conducted globally between 2009 and 2024. Surveyed plants feature various HRSG/steam turbine configurations, and a wide range of operating hours and starts. Plants surveyed include 24 HRSG OEMs, 5 gas turbine OEMs, 11 steam turbine OEMs, and every possible type of cooling and water chemistry. Hours of operation varied from 4000 to 160,000 with up to 2400 starts.

Anderson first focused on tube failures, noting that causes are not tied to any particular HRSG OEM.

"Causes identified as far back as 2008 remain active, and the ranking of failures has not changed," he explained. "Very few tube failures are due to creep damage," he said, "and most are associated with low-cycle fatigue from repeated startup and shutdown." The solution is to identify and eliminate the events causing the incremental damage.

"But low-cycle fatigue is not a root cause," he explained. "And very few are caused by a one-off event."

His emphatic statement: "We know all we need to know to avoid HRSG tube failures! But many plants do not apply this knowledge!"

Effective owner/operator actions should focus here:

1. Look early for symptoms of known causes and take corrective actions.
2. If a failure occurs, remove the failure site for metallurgical analysis and determine the exact failure mechanism.
3. Then conduct precise root cause analysis and take corrective actions promptly. He repeated here that "fatigue is not a root cause."

Anderson's analysis showed that very few plants have a Tube Failure Root Cause Program in place (improved from 0 percent in 2008 to only 9 percent in 2023). The stumbling block is most often management approval to take the time to remove the failure location for analysis, agreed to before the failures occur.

He then discussed basic attemperator issues and hardware inspections. The most damaging issues are leaking spray water causing cracks in thermal liners (Fig 1) and steam pipework (aggravated by incorrect spray valve sequence logic) and by master control/martyr block valve logic which quickly causes leak-through in both valves. Changing to master block/martyr control logic can prevent this leaking, he explained. His cautionary note: "The control valve is also expensive to purchase and costly to repair."

Anderson also noted that overspray will be apparent in the DCS data.

He then covered HPSH/RH drain design issues, the primary optimum being:

1. Thermal liner damage from leaking spray water

- Drain pipe size should be large enough.
- Drain pipes should slope continuously downward.
- Blowdown vessel should be below the SH/RH elevation.

ADVANCED TOOLS AND DRONES

Graeme Gordon, Altrad Babcock (UK), presented *HRSG Inspection tool – a novel remote visual inspection approach*. His case history focused on EDF combined-cycle gas turbine power plants in France and the operator's desire to:

- Gain access to tubes previously unable to inspect.
- Inspect a particular tube if indications are detected.
- Justify relevance of pressure inspection plans to French authorities.

Known damage mechanisms at these plants are flow-accelerated corrosion (FAC), pitting corrosion, and fatigue cracking. The typical maintenance approach has been "reactive" (Fig 2).

The primary difficulties to address: "The owner/operator wants to inspect the internal surfaces the full length of headers and multiple tubes." Traditional challenges have been due to complicated HRSG geometry, inspection ports on tops of headers rather than sides, multiple tube rows per header, and inability to inspect tubes distant from the inspection ports. The goal is therefore inspection of internal surfaces the full length of headers and multiple tubes.

Gordon provided details of the HRSG inspection tool feasibility study and prototypes and gave a detailed look at tool design and trials (Fig 3). He then moved to actual site inspections.

Selected benefits include:

- Accesses entire length of header and any tube within header.
- Fitted with robust navigational camera and lighting.
- Compact and portable.
- Minimizes disruption and reduces overall downtime.

Drones. Tristan Davison, SRG Global, reviewed *Utilizing drones to gain quantitative asset insights*. Barry Dooley added, "In addition to video capability, drones are now capable of ultrasonic thickness testing, EMAT thickness testing, dry film thickness testing, explosive gas detection, thermography and accurate spatial measurements."

HRSG applications are extensive. Davison pointed out that we are now "completing visual and thermographic inspections across a range of locations: burners, superheater panels, air heaters, ducts, hangers, bins and hoppers, stacks, silencers, lagging, tanks and vessels."

One particular item discussed was the ScoutDI for internal and external NDT inspections (Fig 4).

Features/capabilities include surface temperatures 0 to 50C/122F, operating frequencies up to 5Mhz, and inspection thickness range in steel from 3 to 250 mm/0.12 to 9.8 in. This unit is power-tethered for unlimited flight time.

Maintenance planning. Jack Odlum, HRST (US), focused on advanced inspection techniques throughout the HRSG in his presentation *Advanced inspection ahead of major outages for maintenance planning*.

He included inspection methods for economizer, evaporator, steam drum, superheater, duct burner, liner and casing. For this presentation, advanced inspection means non-destructive examination and use of sophisticated camera equipment.

Advanced inspection includes ultrasonic thickness, phased array, dye penetrant and magnetic particle, pulsed eddy current, replication, hardness testing, infrared imaging, borescopes, and use of drones. All were covered in this comprehensive discussion.

His conclusions:

- Advanced inspections see what you normally do not see.
- Large-scale repairs involving pressure parts can be forecast using these techniques.
- Smaller repairs can be properly sourced ahead of the outage.
- Coordinating HRSG projects with known turbine time tables can optimize site outage time, budget, and cost of personnel.

BOILER INTEGRITY

Wayne Hill, Energy Australia, discussed his company's *Boiler integrity program*. His key question: "How do we systematically improve engineering practices for boiler asset management and ensure compliance?"

He went into depth on corporate engineering standards and compliance including guidelines and technical bulletins, working groups and other published documents. The overall program involves site processes (implementing standards and guidelines), boiler inspection management systems (BIMS), tube failure reduction programs, an inspection data management system (IDMS), and audit reviews of site practices. "Periodic audits," he explained, "reveal improvement actions to raise engineering practices on sites and ensure compliance."

The company's Standards are often developed through Technical Working Groups that include principal engineers, site engineers, site managers and operations personnel.

Hill highlighted the corporate boiler tube failure reduction program that features incident procedures and standards, and in-depth research into root cause analysis.

Loy Yang B is a 1200 MW coal-fired station in Victoria's Latrobe Valley, commissioned in 1993. David Desiatov presented *LYB reheater repair and lessons learned*, a project coordinated with HRL.

A tube failure in Reheater 2 had forced Unit 1 off line. The failed tube "had penetrated through the Reheater 2 outlet header

2. HRSG tube failure

3. HRSG header and full-tube inspection tool, Altrad Babcock

4. SRG's ScoutDI drone for UT thickness testing

5. Tube failure at seal box around boiler wall penetration

box," he explained. As a result, three tubes failed (Fig 5). The failure occurred on the Cr Mo side of a dissimilar metal weld (347 stainless to 2.25 Cr 1 Mo).

Evaluations included a temperature profile (ultrasonic oxide thickness testing) and condition assessment (hardness testing and microscopy).

The solution was bend replacement including a seal weld at the seal box.

A lessons-learned outcome was determining remaining useful creep life of thin tubes. Other outcomes were discussed including reliability of thermocouple data.

One of his conclusions: "Thermocouples are an accurate way to calibrate temperature and remaining life software and can be applied anywhere in the boiler, greatly reducing conservatism in calculating remaining useful life."

Through this case study, said Desiatov, "we discovered potential at-risk tubes that remain in service, established a detailed temperature map, and analyzed trends that are critical for future targeted tube sampling."

Smaller outdoor coal units. Anita Zunker, PEi Group, New Zealand, discussed cases of *Widespread corrosion of wall tubes* in two 32 MW coal-fired boilers. Wall tube corrosion had not been considered a high risk to these units' owner/operator, and the supplier no longer existed (commissioned in 1994 and 1996). Under-casing corrosion had not been investigated. The outside units also experienced rainwater ingress into the casing.

Eventually, heavily-pitted tube surfaces and corrosion became apparent, but areas were difficult to access and repair processes were expensive.

Detailed investigations and step-by-step assessments began. Casings were removed for assessment by visual, UT, pit depth measurement, and laser scanning (Fig 6). This included validations by destructive testing. Extensive tube corrosion was identified, and operators developed and executed a "robust inspection and analysis scope for tube corrosion."

Fitness-for-service repair works began and results have extended the boiler retirement plans.

Callide B. Gerrie Visser, CS Energy, offered *Secondary and tertiary superheater inlet header tube stub cracking* and discussed stub cracking at the 700 MW fossil-fueled Callide B Power Station in Central Queensland. During a 2023 outage, inspectors found multiple defects in the SH stub tubes adjacent to the manifold-to-stub fillet weld. A comprehensive repair program began.

Highest stress had occurred during startup, believed to be due to restrained thermal expansion during startup. Movement was limited by the refractory roof.

Action options include changing the penthouse and installing membrane seals.

STEAM TEMPERATURES

Steven Bond, Bond Engineering, Australia, presented *CCGT HP and RH attemperator turndown and reliability improvements*. His case study was an Alstom 13E2 gas turbine with duct-fired Alstom HRSG. The unit suffered reheat spray nozzle failures and Bond offered solutions including improved control philosophy, piping design/stress issues and resolutions, and general troubleshooting tips.

Stuart Mann, AGL Energy, Australia, offered *Analysis of drivers of high superheater temperatures* for an IHI/Foster Wheeler coal-fired boiler.

He discussed the influence of the HP heaters at various loads, and the influences of over-firing and rapid fuel cycling variations.

He discussed AGL's projects now in place to address the issues.

CHEMISTRY

Barry Dooley gave his update on *Fossil and HRSG cycle chemistry control and FAC*.

He noted that "statistics from detailed assessments of close to 300 plants worldwide indicate that monitoring corrosion products is the primary influence on availability, closely followed by deposits in waterwalls and HP evaporators, inadequate instrumentation, and challenging the status quo."

Dooley and David Addison, Thermal Chemistry (New Zealand), also provided a review of international activities on film-forming substances. This highlighted current needs on the effect of FFS on growth mechanisms of Fe, Cu and Cr oxides in water and steam, as well as research on changing from one FFS to another.

Updates were also presented on the International, Australian and New Zealand Associations for the Properties of Water and Steam.

Summarizing, Dooley pointed out that the new IAPWS decay map provides the first indicator to validate whether a plant's chemistry is optimized and provides a tool to quantify any benefits from an application of

6. As-found tube corrosion condition after casing removal

7. Damaged main steam isolation valve above HRSG


INDUSTRIAL CLEANING SERVICES
CLEAN-CO SYSTEMS
CHEMICAL CLEANING DRY ICE HYDROBLASTING INSPECTIONS
Rails Are Available To Match Any Size Tube Bundle
CleanCo Systems will stock standard length rails OR will customized to fit your needs.
The Helix Rotator Aligns The Hose With Each Tube
Line the hose up with each individual tube in the mud drum before launching the hose.
FIN FAN COOLERS
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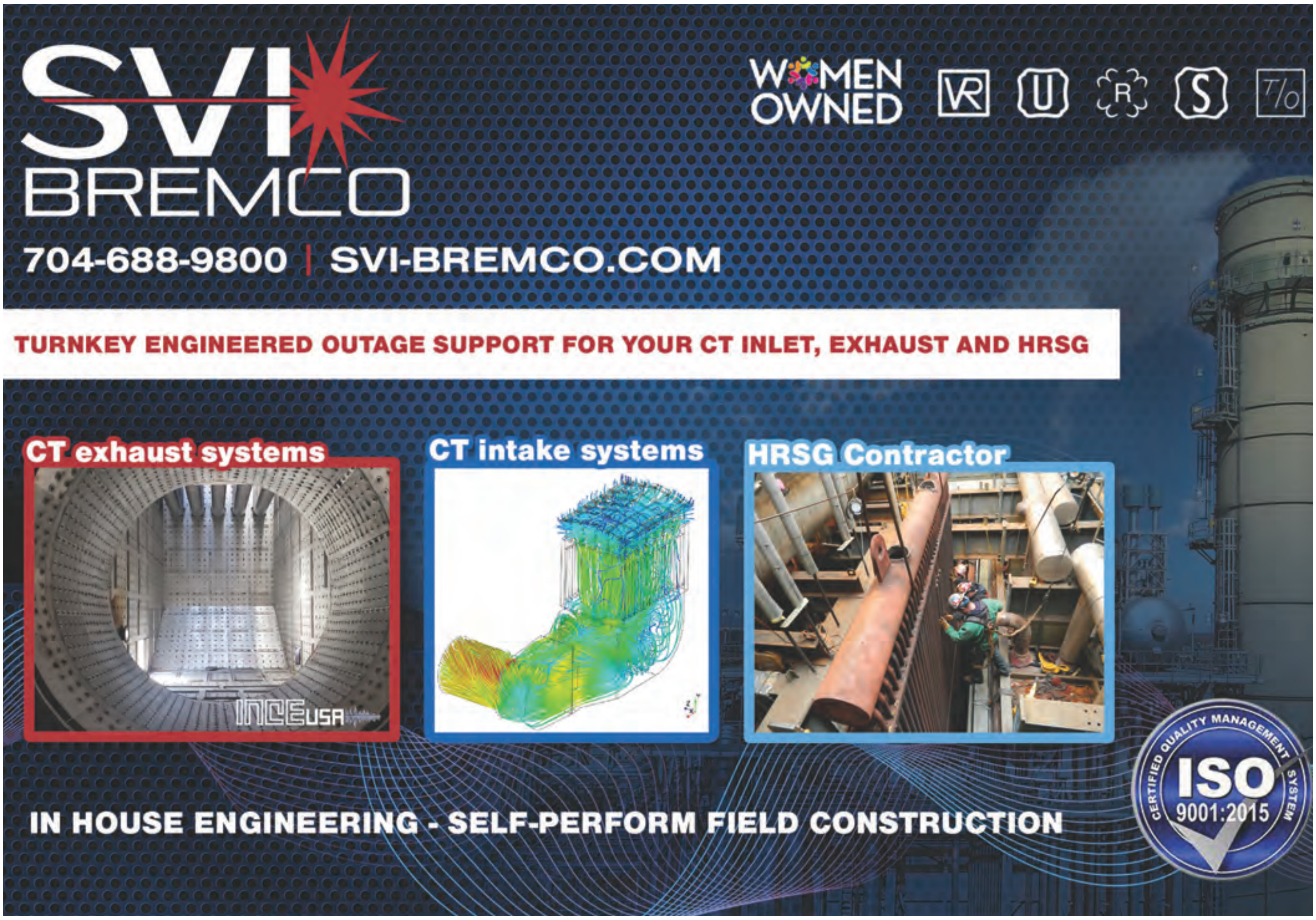


a film-forming substance. With the growth of renewable energy forcing conventional and CCGT plants into more and more flexible operation, the benefits to plants from understanding and then controlling the factors leading to corrosion product transport will be very significant. Dig deeper into the new IAPWS tool by accessing the nearby QR code.

ROUNDING IT OUT

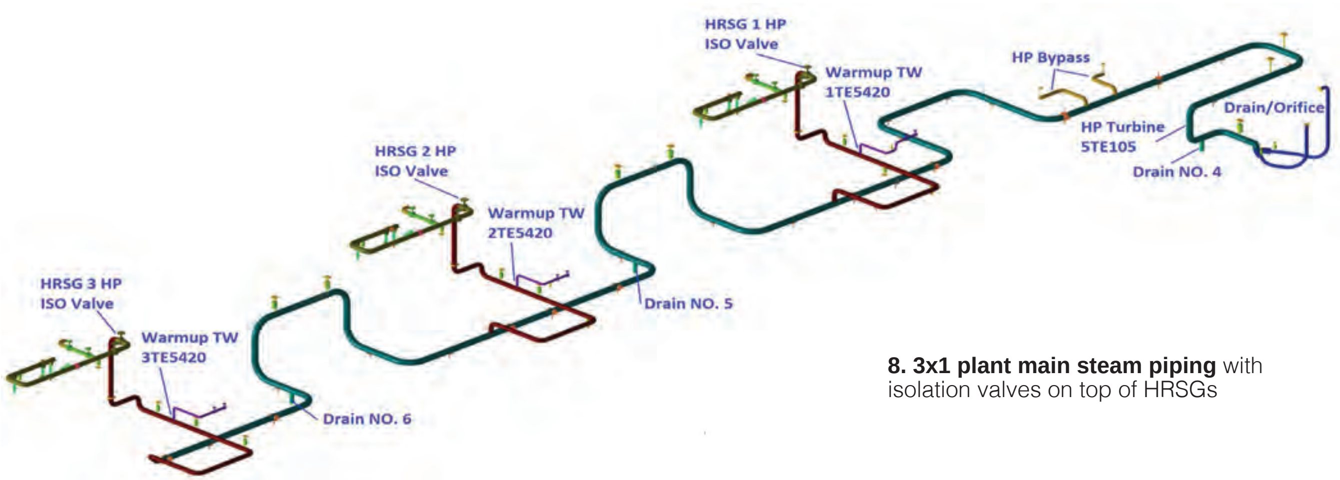
A number of other specific case studies were presented and examined. One, for example, looked at damage caused by undrainable water accumulated in main steam pipework, leading to long deadhead sections upstream of isolation valves.

Tom Burnett, Intertek (US), offered a review of *High energy piping dead-leg concerns for CCGTs*. His examples were taken from Capital Power in Canada.

His first example was damage to a high-pressure main steam piping isolation valve on top of an HRSG (Fig 7). He then offered an overview of a typical 3 x 1 main steam piping system (Fig 8) and walked through the illustration during plant operations.

His premise: "Potential HEP quenching due to long dead-leg design in between the HP, RH and LP to the common header is a condition that is not monitored in the typical CCGT plant."

"The challenge," he noted," is that the dead legs without flow can have saturated condensate accumulate with higher temperature superheated steam higher in the pipe. Also, when shut down, the pipe wall temperature will be higher, and saturated



8. 3x1 plant main steam piping with isolation valves on top of HRSGs condensate will tend to be at the bottom of the pipe.'

This temperature differential "may cause the pipe to bow and create an area for saturated condensate to accumulate, significantly increasing the risk of a water hammer and pipe quenching." He offered various plant examples.

Burnett stated, "Because most HEP systems only monitor internal steam temperature with thermal wells at midpoint or higher in the pipe, the operator will not know if there is saturated condensate in the pipe during startup, leading to potential damage. The solution is to have a minimum of top and bottom pipe surface thermocouples installed."

And a caution: "Over long operating time, the piping will creep and will challenge the elevation depending on the support system design, especially at the bottom of risers. Elbows at long horizontal runs may lift as well."

Roy Russell, Dekomte, discussed *Side wall penetration seals and ash hoppers*. His case studies focused on turbine exhaust expansion joints and HRSG penetration seals, a fossil boiler ash hopper, and a waste-to-energy boiler grate.

For combined cycle plants, he discussed fabric expansion joint technologies for GT exhaust/HRSG inlet hot and cold casing, variations for penetration seals, and side-wall close proximity seals. This included a new concept, a combination of nozzles into a staggered penetration seal focused on "insulation integrity in the casing and around each nozzle" as well as multi-pipe penetration seals (Fig 9).

He then moved to conventional boiler ash handling systems and waste-to-energy units.

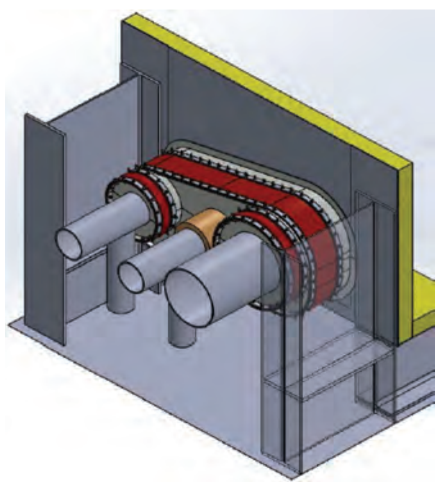
Sam Clayton, HRL Technology, discussed *Plant performance and its relationship with plant integrity* noting strongly that "combustion is the least controlled process" and should be a key focus area. He also highlighted air heater performance and electrostatic precipitator performance in fossil boilers.

Stan Rosinski, EPRI, presented *Evaluation of cleaning technologies for fouling removal and potential tube damage in boilers and HRSGs*. His discussion focused on explosive cleaning methods and foam cleaning.

Additional ABHUG 2024 presentations covered *Electric heating of HRSGs during wet layup* (Anderson), a case study on inspection and assessment of *Nozzle crack-like defects on a high-pressure feedwater heater* (SRG Global), the *Impact of FFS on heat transfer* (Nalco), *Non-fossil steam production in Australia* (Addison), *Australian standards on pressure equipment in-service inspection* (HRL), *Backup production of ultrapure water* (Water Rentals), *Corrosion-control lessons from the petrochemical industry* (Quest Integrity), *Addressing damage mechanisms in HRSGs* (Quest Integrity), and *Deaerator cracking/blowdown system erosion and early life creep damage* (INPEX Australia).

Sponsor presentations were included for HRL, Precision Iceblast, Swan, Flotech, Duff & Macintosh, HMA Instrumentation, Intertek, and RTR Group.

The next meeting of ABHUG will be in Brisbane from November 25-27, 2025. Details at the group's new website, www.abhug.com, as they become available. CCJ



9. Staggered penetration seal for nozzle combination

Faribault's 14 years of performance, financial success

By Shawn Flake, NAES Corp, and **Stacy Willis** and **Dave Gebhard,** Veolia Water Technologies and Solutions

Faribault Energy Park, a 300-MW gas-fired combined-cycle facility located in southern Minnesota, represents a significant investment in sustainable energy infrastructure. Owned by the Minnesota Municipal Power Agency (MMPA) and operated by NAES Corp, the plant was commissioned in 2007.

Initially, Faribault used mobile ion-exchange trailers for steam makeup water because of restrictions on discharging wastewater from a reverse-osmosis (RO) system. This setup posed operational challenges, particularly during Minnesota's harsh winters, leading to icy conditions and potential safety hazards (Fig 1).

To address these issues, a plan was developed to construct a heated building for the mobile trailers, with provisions for a permanent water treatment system contingent on obtaining a permit to discharge RO reject water to the cooling tower.

In 2010, a permanent water treatment system was installed, and in 2012 Faribault received a Best Practices Award from CCJ for its design. The system included ultrafiltration (UF), two-pass RO, and polishing with exchange-service mixed-bed deionization (MBDI) vessels.

This strategic move aimed to enhance operational efficiency, reduce costs, and improve safety. Fourteen years later, the analysis that follows examines whether the original business case for the permanent water treatment system has been realized, evaluating its performance and cost savings as compared to initial projections.

The first step was to develop and receive approval for the plan to account for the reject stream. MMPA, in coordination with the cooling-tower chemical service provider, presented a plan to the municipal regulators. It showed the RO concentrate was of similar quality and less than 0.01% of the cooling-system volume and would have minimal impact to blowdown water composition. Approval for the plan was received from the municipality.

The plant is supplied water from a well that feeds the multi-pond storage system prior to entering the plant. The pond system also collects rainwater from the area and provides buffer capacity during periods of peak demand. In addition, the ponds are open to the public for recreational sport fishing.

2. Trailers with ion-exchange vessels were replaced by a compact skid incorporating ultrafiltration and two-pass reverse osmosis systems

The pond system experiences high turbidity peaks and high water-temperature variability, which introduce challenges for a membrane system design.

Plant personnel drafted a detailed RFQ and solicited equipment proposals from water-industry OEMs. Mechanical design and installation were completed in-house by collaborating with both the OEM selected for overall process design and a local electrical contractor.

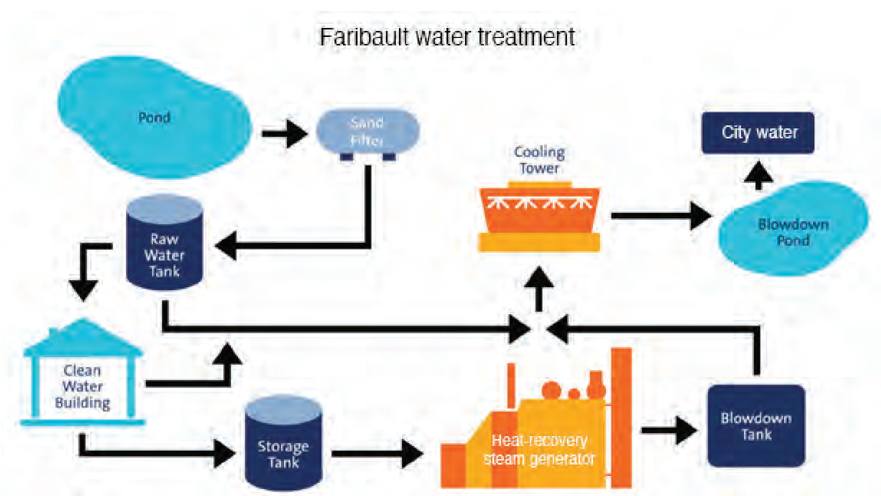
The plant provided feedwater-quality and boiler-feedwater specifications to drive the process design. To achieve the required product-water quality, the team selected a design consisting of a two-pass RO system feeding exchange-service MBDI vessels for polishing the final product water to meet specifications.

An additional challenge identified was that the existing multi-media filter (MMF) used for cooling-tower makeup water would not meet RO membrane feedwater requirements specific to turbidity and silt density index (SDI) values. OEMs proposed solutions ranging from coagulation with a second MMF to pressurized ultrafiltration (UF).

Given the variable water quality and temperature, UF was selected to pretreat water flowing to the RO system. It provides superior and consistent water quality compared to conventional media filtration and is fully automated, including CIP (clean in place).

UF can filter particulate matter down to

1. Ion-exchange trailers were specified for Faribault because of restrictions on the discharge of wastewater from an RO system. However, they posed operational challenges



3. Faribault takes water from onsite ponds and processes it for use in the plant's heat-recovery steam generator and cooling tower. Fig 2 shows what's inside the clean water building

0.1 micron as compared to MMF's typical 20-micron capability. The coagulation + MMF would have required higher operator involvement for chemical and operational adjustments because of turbidity levels and temperature variability. Veolia Water Technologies and Solutions was selected and provided a UF and two-pass RO in a compact skid design system (Fig 2), which is located in the clean-water building (Fig 3).

PERFORMANCE HIGHLIGHTS

The UF system undergoes a standard automatic maintenance clean three or four times weekly, plus an offline recovery clean quarterly. The UF membranes are replaced after seven years of service versus the original estimate of five years. Savings versus budget for UF membranes totaled about $58,000.

The feed turbidity to the UF unit varies significantly as the existing MMF upstream provides coarse filtration of pond water while the UF filtrate is exceeding feed specifications for the RO. By the numbers:

- Average feed turbidity, 45 NTU.
- Maximum feed turbidity, 190 NTU.
- UF effluent turbidity, <0.2 NTU.

RO (two pass)/MBDI exchange. RO maintenance over the last 14 years included quarterly membrane cleanings and replacement of a few instruments, rebuilding of a couple of valve actuators, and standard pump service. Personnel estimate that an average of 15 min/day is spent on data collection and general maintenance.

Based on water sampling completed in March 2022, with original membranes operating for 12 years, the water quality was as follows:

Water source	Conductivity, µS/cm	Hardness as CaCO3	Reactive silica, mg/L
Raw feed	660	300	18.7
First-pass permeate	16.2	0.55	0.5
Second-pass permeate	<3	0.13	0.025
Mixed-bed effluent	<0.04	0.02	<0.002

RO membranes were replaced in February 2024 after 14 years of service, versus the original projection of five years. The membrane reload took plant personnel four hours with OEM support. Saving based on membrane life versus budget was about $10,000.

BUSINESS CASE, BENEFITS

The business case for the permanent water treatment system included these several key benefits:

- The capital system provided a simple payback of 1.52 years versus the projected 1.8 years.
- Over the 14 years evaluated, the system saved MMPA stakeholders $4.9 million in operating costs—savings attributable primarily to removing ion-exchange trailer fees.
- It was estimated that the project avoided 25,000 miles of semi-truck transport for the mobile deionization, equivalent to 37 metric tons of CO2.
- The system mitigated safety hazards associated with transportation, ice buildup, and other weather concerns. Plus, there have been no recordable accidents associated with the plant water system.

In conclusion, review of all available data demonstrates the project met or exceeded the initial investment case and contributed towards stated objectives of the stakeholders—including MMPA, NAES, and the MMPS member cities, board of directors, and community. The project lived up to its 2012 recognition for best-in-class design and has exceeded expectations in delivering critical financial and environmental benefits for the MMPA stakeholders.

Finally, Veolia Water Technologies and Solutions contributors to this article included the following: Brian Wise, Todd Langford, and Derek Brandt. CCJ

ACCUG 2024: Global collaboration drives air-cooled condenser innovation

The 15th annual meeting of the Air-Cooled Condensers Users Group (ACCUG) was held at the University of East London (UK) July 23-25, 2024. Principal content categories were chemistry and corrosion, air-cooled condenser (ACC) design and performance, and system operation and maintenance.

The event was chaired by Andy Howell, EPRI; Barry Dooley, Structural Integrity (UK); and Riad Dandan, Dominion Energy.

CHEMISTRY AND CORROSION

Barry Dooley began the sessions with *Corrosion and cycle chemistry*, reviewing a 20-year global history of data from fossil, combined-cycle and industrial power plants. He noted that ACC systems come in various sizes, but the flow-accelerated corrosion (FAC) damage is the same worldwide with all system chemistries and plant types.

His comments covered:

- Reminder of ACC damage and how it is normally addressed.
- The Dooley Howell Air-Cooled Condenser Corrosion Index (DHACI) for uniformity for inspections worldwide.

His review of film-forming substances (FFS) focused on international experiences and the ongoing need for information and site trials.

He included a detailed listing and discussion of IAPWS Technical Guidance Documents for combined cycle plants with ACCs, all freely available at www.iapws.org.

Durgesh Lohiya, NTPC Limited, India, then offered *Design details of condensate polishing unit (CPU) systems of NTPC ACC-based projects*. He addressed CPU design, major chemistry issues, and cycle chemistry parameters. He noted that CPU design and operation for very high influent (flow) ammonia is a new challenge to NTPC.

He discussed the NTPC deep mixed bed design with external regeneration system for existing supercritical and ultra-supercritical units, for 150 to 1500 ppb influent ammonia.

Lohiya reviewed various large plants, and operating challenges and maintenance issues.

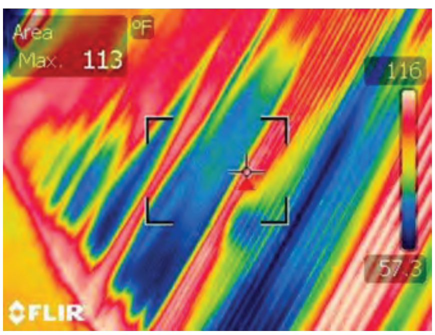
Manfred Jansen, Anodamine Incorporated, then outlined *Experience of Anodamine in plants with ACCs*. He stated that Anodamine is:

- Non-amine-based film forming technology added to the plant's conventional chemistry.
- Thermally stable above 1050 F with no effect on conductivity after cation exchange (CACE) and no effect on cycle pH.

Jansen reviewed several cycle chemistry challenges (solid particle corrosion, FAC in LP turbine ducts, oxide deposits, decomposition of oxide products, insufficient passivation, etc.). He also noted extensive plant experience and studies coordinated with the Electric Power Research Institute (EPRI).

DESIGN AND PERFORMANCE

John De Winter, John Cockerill Hamon, began the session with *Alternative induced draft ACC solution*, first discussing induced-draft benefits and challenges. He then focused on a case history in Belgium featuring a modular ACC riser supported (MARS) design with the gearbox/motor at the bottom of the cold air stream for improved maintenance and reduced vibration.



1. Subcooling in the condensate manifold

Sean Cusick, SPG Dry Cooling, offered *Unlocking efficiency: overcoming subcooling challenges in ACCs*.

He began with ACC fundamentals and focused on subcooling: "the difference between the calculated saturation temperature and the actual condensate or non-condensable temperature." This is illustrated in Fig 1.

He outlined the sources of subcooling:

- Uneven steam distribution.
- Air flow (too much from fan or wind).
- Steam surface availability.
- Vacuum system issues.
- Air ingress.

Subcooling, he said, leads to:

- Freezing and a loss of efficiency.
- Air ingress.
- Higher backpressure.
- Increased fuel consumption and auxiliary load.

A fundamental: "Where there is air there is not steam; where there is steam there is not air. Condensate subcooling increases when the condensate passes through air within the heat exchanger."

His bottom line: ACC performance matters; it impacts steam turbine output.

Cusick referenced a case study of the CPV (Competitive Power Ventures) Valley Energy Center in New York. To address negative impacts of continuous subcooling, even after a number of leaks were repaired, CPV implemented SPG's remote performance monitoring system (ACC360), a "cloud-based solution that provides unprece-

2. Innovative structure ACC, Canada

dented insight into the performance and health of any ACC" through data analytics and modeling. For more on this plant, access the nearby QR code.

Huub Hubregtse, ACC-Team Technology, *ACC performance improvement*, discussed ideas of narrower tubes, louvers in fins to improve heat transfer, fan modifications for air flow improvement, wind walls, losses through hot air recirculation, fouling, and use of adiabatic cooling (fogging) to reduce ambient temperature.

Jason Dehem, AX Systems, then offered *More performance with optimized resources*. He reviewed causes for decreased ACC performance and potential solutions, focusing on airflow under performance.

His talk looked at tube cleaning options, fouling's impact on fans' electric consumption (increased fan speed), benefits of fogging, and fan upgrades. His theme: "cleaning, fogging and fan upgrades are significant and complementary drivers for increased ACC performance."

Jeff Ebert, Galebreaker Industrial, looked at *Mitigating wind effects from high seasonal winds*. He first addressed how wind and turbulence impact blade loading and ACC performance, followed by the benefits of wind screens to reduce wind effects.

Ebert discussed the 350 MW gas-fired project in Saskatchewan, Canada, with its innovative-structure ACC. See Fig 2.

Results show improved ACC thermal performance at a variety of wind speeds and ambient temperatures.

Mohammadreza Vaghar, Mapna Development Company, Iran, offered an *Investigation of air flow over ACC tube bundles to improve cooling system efficiency*.

This reviewed ACC module geometry, numerical modeling strategies (ACC and fans), fan stator blades and shrouds, data gathering methods and future studies. See Fig 3.

György Budik, MVM EGI, Hungary, covered *Medium- to large-size hybrid cooling systems*.

The hybrid wet/dry system combines some advantages including good performance in summer, low power consumption, limited water consumption, reduced plume, reduced chemical dosing and reasonable maintenance cost (among others). He reviewed both separate-circuit and single-circuit systems. He also reviewed Heller indirect dry cooling with supplemental spraying.

Chris Meyer, Notus Fan Engineering/Stellenbosch University, outlined *From academia to industry (advanced fan technology)*. This presentation reviewed innovations in design based on aerodynamics, structural design, strength testing, and fan blade manufacturing. Field examples covered vibration testing, torque, power reduction, and an indexing system for blade strength. See Fig 4. Meyer, Stellenbosch University (South Africa), would follow later with *Latest ACC research at Stellenbosch University.*

Cosimo Bainchini, Ergon Research (Italy), updated *Recent progress in modeling of wind effects*. Details included high-fidelity CFD, high performance computing, and wind screen layout validations.

Eleanor Baimbridge, Suez UK, followed with *Live performance modeling of energy-from-waste plant ACCs*. Examples focused on recycling and resource recovery plants in the UK. Suez, a resource management company, is the fleet/plant operator of 11 UK energy-from-waste plants with a total generating capacity of 233 MW.

Bainbridge explained the variations and challenges of operating ACCs within a fleet with various ACC OEMs and site-specific cooling requirements. ACC performance modeling is used by Suez to improve cleaning schedules, identify unit defects, and increase MW output.

Case studies were presented on the effects of unit fouling, cold weather operation, cleaning requirements, ambient environment, impact of turbine modifications, and predictive monitoring for ongoing operations.

Kris Herijgers and Rob Green, Sumitomo Drive Technologies, presented *ACC cooling technology gearbox evolution*, offering first a history from generic to dedicated fan drives (Sumitomo and Hansen) with operating examples in the UK and US.

The presentation then focused on the advantages of a "dedicated" design with rigid housing, strong foot base, extended bearing span, cooling fins, and flexible cooling options. Also presented was a unique conditioning monitoring system for gearbox life cycle improvement.

OPERATION AND MAINTENANCE

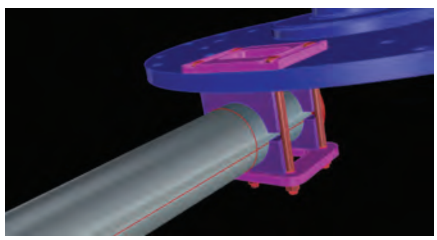
Lee Rhodes, Enfinium/Ferrybridge Power Station offered *Ferrybridge performance improvement.*

Ferrybridge is an 85 MW waste-to-energy facility in the UK (Fig 5), on line in 2015, with two boilers and one steam turbine processing 750,000 t/d of municipal waste. Gross power output is 86 MW.

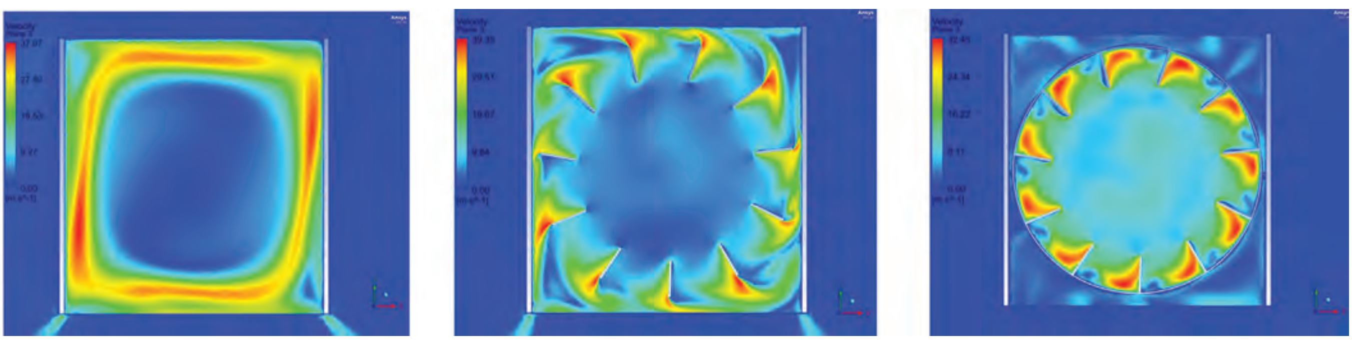
The site installed Galebreaker wind screens on one unit based on CFD modeling in a cruciform and perimeter screen layout. Rhodes then showed comparative results of the units, with positive results on ACC vacuum vs ambient temperature following wind screen installation.

Mohammad Asim, ENGIE-Fadhili, Saudi Arabia, discussed *ACC wind mitigation project experience*. The subject plant features 4 GTs and 2 ACCs (24 cells each), facing high vacuum issues since commissioning.

Vacuum issues are based on high wind



4. Notus indexing system



Without stator | Stator without shroud | Stator with shroud

3. Models of more uniform air flow pattern with stator blades and shroud

5. Ferrybridge 1, United Kingdom

speed, high summer ambient temperatures, and high dust (sand), all leading to plant load reduction. An adiabatic cooling system installed for increased ACC performance led to unacceptable water consumption.

The solution was CFD modeling and Galebreaker wind screens. Load reduction events were reduced, and plant availability and reliability improved.

Patrick Saususs, Evapco Dry Cooling, offered *Fan modification impacts on ACC vibration*. His case study was the Virginia City Hybrid Energy Center, owned and operated by Dominion Energy.

This coal waste and biomass plant features 2 ACCs with 7-blade fans, 30 cells each. Blade cracking (Fig 6) has been an issue since 2016. The solution in this case was the 9-blade FanTR design (Fig 7). Installations began in 2018.

This case history covered vibration fundamentals and standards as well as gearbox mounting studies.

One lesson learned: Seemingly minor modifications can have a big impact. You must look at frequencies in multiple directions, and be cautious of multiple fan interactions.

Jacques Muiyser, Howden (Netherlands), offered a *Low noise ACC retrofit case study*.

In this Howden Netherlands case study, the 10 existing fans had been in operation for 20 years. The goal was to improve cooling capacity in summer with no increase in noise level. The owner/operator also wanted to implement fan speed control to reduce fan power consumption when additional cooling was not required.

The retrofit method discussed involved baseline measurements of the existing fans, new fan selection, detailed engineering of fans and other components, and safety assessments, followed by delivery and commissioning specifics.

A Howden model 6116SX15 (Fig 8) was selected to deliver 30 percent more flow than the existing fans. Although the fans would run at higher speed, a decrease in sound power level of 3 dBa was expected. VFDs for fan speed control were added.

During commissioning, a reduction in blade angle of approximately one degree resulted in a desired increase in air flow while not exceeding the maximum allowable motor power. High vibrations occurred and the solution was additional stiffening plates to the fan casing.

"Due to the implementation of VFDs and speed control, energy could be conserved during periods where additional cooling was not needed," he said: "This was a good example of every retrofit project is unique."

6. Fan blade cracking

TOUR INFORMATION

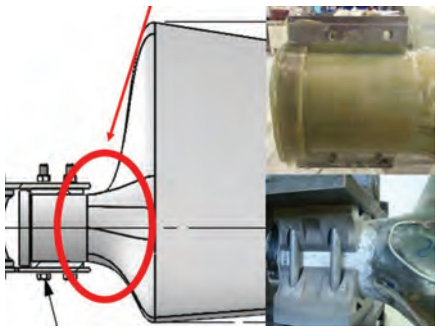
Christian Keefe and Valerio Teducci, InterGen, presented *Coryton Power Station ACC: operation, performance and engineering*. A Coryton tour would conclude the 2024 conference, courtesy of InterGen and organized by plant manager Tony Wren.

Coryton's GEA Power Cooling Systems ACC was commissioned in 2002. The plant generates 800 MW in a 2 x 1 combined cycle. Originally designed for base load, Coryton is now in two-shifting operation.

The ACC contains 40 cells in 8 rows of 5 fan bays. ACC operational control is manual (4 rows always open, 4 rows selectable).

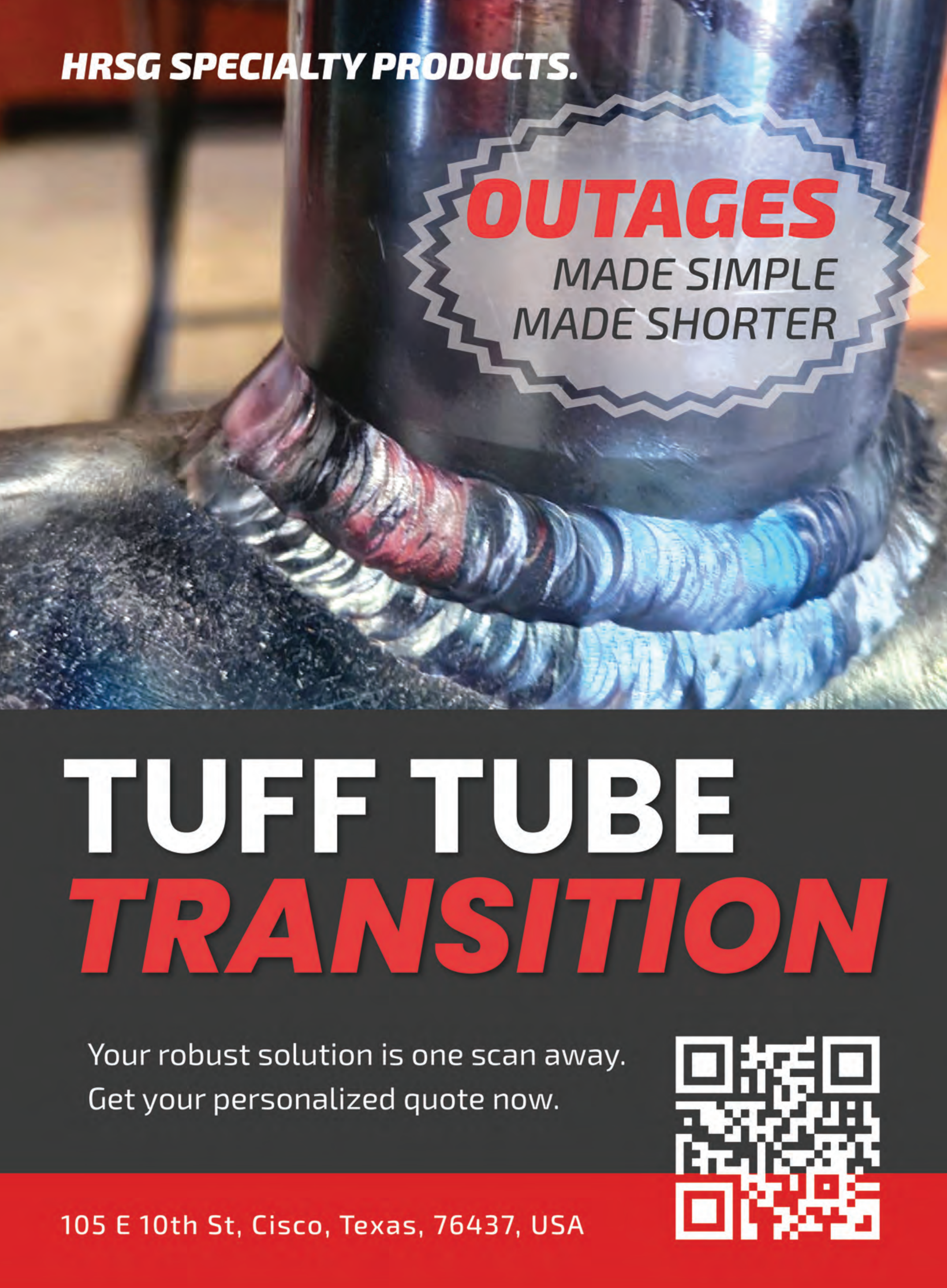
This presentation offered details on:

- Design.
- System and plant start.
- Freeze protection.
- ACC fogging system.
- Data monitoring.
- ACC wash.
- Air ingress survey.
- Fogging system – can be used above 77F ambient.
- Galebreaker wind screens, perimeter and cruciform.
- They then offered a detailed list of equipment improvements to date, as well as future considerations.



7. Evapco FanTR design

8. Completed installation Howden 6116SXT5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St. Charles Energy Center

Owned by CPV Maryland LLC
Operated by Consolidated Asset Management Services

745 MW, 2 × 1 7F.05-powered combined cycle equipped with a GE D11A steam turbine, located in Waldorf, Md

Plant manager: Nick Bohl

Influent water monitoring upgrade for permit compliance

Challenge. St. Charles Energy Center uses recycled wastewater from the local municipality to meet the facility's cooling needs. Treated wastewater is piped 14 miles to the plant and stored in the reclaimed-water tank. After use, water is returned to the wastewater treatment facility for processing.

The use of reclaimed water is governed by a permit specifying the parameters that must be met for its discharge—including restricting TSS to less than 400 mg/l. The standing process for evaluating TSS was to take a 24-hr composite sample monthly and send it to a local lab for testing. This was not ideal because it takes seven to 10 days to receive the results. The site needed a way to evaluate TSS in real time.

Solution. While evaluating options for real-time TSS monitoring, personnel realized the instrumentation setup for the existing wastewater sampling panel presented multiple maintenance challenges. Example: It relied on four instruments to measure specific conductivity, pH, ORP, and turbidity (Fig 1). The four probes were on a common sample line without individual isolations; thus, all four had to be taken out of service to maintain one of the elements. Plus, the panel had multiple transmitters of different models, requiring different sets of spare parts.

Staff reached out to companies specializing in wastewater monitoring to identify and evaluate equipment that could be implemented to monitor the influent and effluent water. Solution was to purchase an Endress + Hauser product that uses light sources and detectors to measure suspended solids in the water while allowing personnel to monitor and compare the incoming and outgoing TSS levels.

A review of the local human/machine interface system revealed that the plant had a DCS indication for incoming free chlorine, but its measurement was based solely on ORP data. Free-chlorine calculations should consider both ORP and pH. This issue was resolved by creating logic that uses the pH and ORP measurements to interpolate the free-chlorine value.

After planning and review, the site was able to install the new influent water sampling system (Fig 2) which addresses the maintenance challenges of the old system. The new panel is configured for all the instruments to run off a common transmitter, reducing the amount of spare inventory required. Plus, it allows isolation of one instrument at a time for maintenance.

An online TSS probe was added to the effluent water sample panel, allowing staff to compare TSS in the incoming water to that in the water discharged.

Results. The online TSS and sample-panel upgrade give the plant better insight into the quality of the reclaimed water—both incoming and discharged. Having the sample values displayed on the DCS allows the operations team to react quickly to changes in incoming water quality to protect equipment that relies on this water for cooling.

Additionally, it is now possible to monitor and evaluate TSS trends in the incoming and outgoing water to determine cleaning frequencies for the cooling-tower basin and wastewater sumps.

Project participants:
Jacob Boyd, plant engineer
Lauren Sparks
William Bates
Chris Higgs

1. Existing influent sample panel had several shortcomings

2. Upgraded influent sample panel provides better insight into water quality

3. DJI Air 3 drone enables the capture of high-resolution photos and videos not previously possible

NOx controls project mitigates CEMS maintenance challenges

Background. St. Charles Energy Center is equipped with a selective catalytic reduction (SCR) system to regulate NOx emissions released to atmosphere. It includes an ammonia injection grid to treat the flue gas before it reaches the SCR catalyst bed. The control system responsible for managing NOx levels relies on a continuous emissions monitoring system (CEMS) to regulate the amount of ammonia injected into the flue-gas stream.

Challenge. During extended periods of operation, the CDMS needs online troubleshooting, updates, and/or inspection, requiring the system to enter a "maintenance mode." However, placing the CEMS in maintenance mode leads to a loss of reference input for the Mark VIe control system, preventing commands from being issued to the ammonia flow control valves. This requires the operations team to manually control ammonia injection based on stack NOx levels to ensure compliance with air permit regulations.

Solution. To address this challenge, St. Charles initiated an "Ammonia Flow to Load" project within the control system. It eliminates the need for manual intervention by operators in controlling the ammonia valve and provides a more robust control mechanism for NOx emissions.

The new controls arrangement incorporates these two additional distinct strategies to enhance flexibility and accuracy in NOx emissions control:

- Mass-balance control strategy uses exhaust-gas mass flow, actual NOx measurements before the SCR, and target NOx levels at the stack to provide commands to the ammonia control valves. This required data from multiple months of operation—including run profiles and startups and shutdowns—which were collected from the PI system. The data provided insight to the stoichiometric relationships between different elements to ensure proper control of ammonia injection.
- Load-based control strategy acts as the third level of control for the ammonia injection system. It is used if the SCR inlet-NOx measurement is unreliable or unavailable. Control of the ammonia injection system is determined based on gas-turbine megawatt load and DB Btu output.

Results. The project successfully mitigated operational challenges associated with CEMS maintenance, enhancing the overall reliability and accuracy of the NOx emissions control system.

Implementation of ammonia-flow-to-load controls provided several benefits, including the following:

- The new logic aids operators in controlling NOx while the CEMS is in the maintenance mode, eliminating the need for manual control. This allows the site to remain compliant under the current air permit assigned by the state of Maryland.
- The logic provides an extra level of control for the ammonia injection system.
- Doubles the control scheme for the ammonia control system—including CEMS, mass-balance, and megawatt control, with manual control a last resort.

Project participants:
Plant personnel with the participation of AtkinsRéalis (formerly SNC-Lavalin) as the lead controls engineering team

Drones enhance plant safety, reliability

Challenge. St. Charles Energy Center faced numerous obstacles hindering efficient completion of inspection tasks—including high costs, time constraints, and limited physical access—all while placing personnel in a higher-risk environment to accomplish the work required.

The facility property line encompasses diverse terrain, ranging from woodlands to hills and marshes, thereby posing significant challenges for access by foot or utility terrain vehicles (UTVs). Inspections and maintenance of the heat-recovery steam generators (HRSG) were particularly laborious and expensive. Nearly all tasks involved scaffolding, which often led to additional costs and delays.

The site needed a way to conduct comprehensive visual inspections of plant grounds, buildings, and equipment in a cost-effective and timely manner.

Solution. To overcome these challenges, St. Charles invested in a DJI Air 3 camera drone (Fig 3) for external inspections and leased a Flyability Elios 2 drone (Fig 4) for internal checks of HRSGs and stacks. This strategic combination of drone technologies revolutionized the plant's inspection processes, enabling it to avoid the limitations previously encountered. Important to success was the site's ability to leverage the operation manager's remote pilot's license issued by the Federal Aviation Administration.

The DJI Air 3 enables the capture of high-resolution photos and videos from vantage points previously inaccessible, providing unparalleled visibility of the plant's exterior. Meanwhile, the Flyability Elios 2, equipped with advanced onboard lighting and 4K cameras, permits internal inspections of HRSGs and stacks with precision and thoroughness.

Results. Beyond the initial intended applications of conducting perimeter and HRSG internal inspections, the drones have unveiled a multitude of additional use cases. St. Charles has leveraged these versatile tools to capture timelapse footage of newly installed capital projects, assess building roofs and gutters before and after severe weather events, conduct winter insulation audits, perform stack inspections, and examine silencers for maintenance needs.

4. Flyability Elios 2 is equipped with an advanced onboard lighting system and 4K cameras

Moreover, the HRSG internal inspections yielded significant improvements in workflow efficiency. As a direct result of insights gained from the inspection process, modifications were made to the work scope, optimizing scaffolding placement. This adjustment reduced scaffolding erection time by eight hours, demonstrating one of the tangible benefits derived from the integration of drone technology into plant operations.

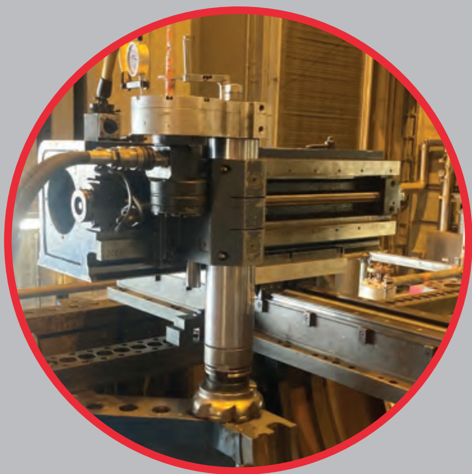
Furthermore, the use of aerial views on gutter inspections eliminated the necessity for operators to climb ladders in areas inaccessible by manlifts. Additionally, staff was able to pinpoint specific locations for clearance via manlift, improving safety and reducing total job duration by 75%.

During a post-storm perimeter check, the drone enabled its operator to identify a damaged fence caused by a fallen tree. This allowed the plant to bring in resources to remove the tree and repair the fence, thereby preventing wildlife and unauthorized personnel from entering the premises.

Harnessing the power of technology, through the versatile use of drone applications, St. Charles has recognized tangible improvements in workflow efficiency, safety, and cost-effectiveness.

Project participants:
Nick Bohl, plant manager
Nick Ruscillo, operations manager

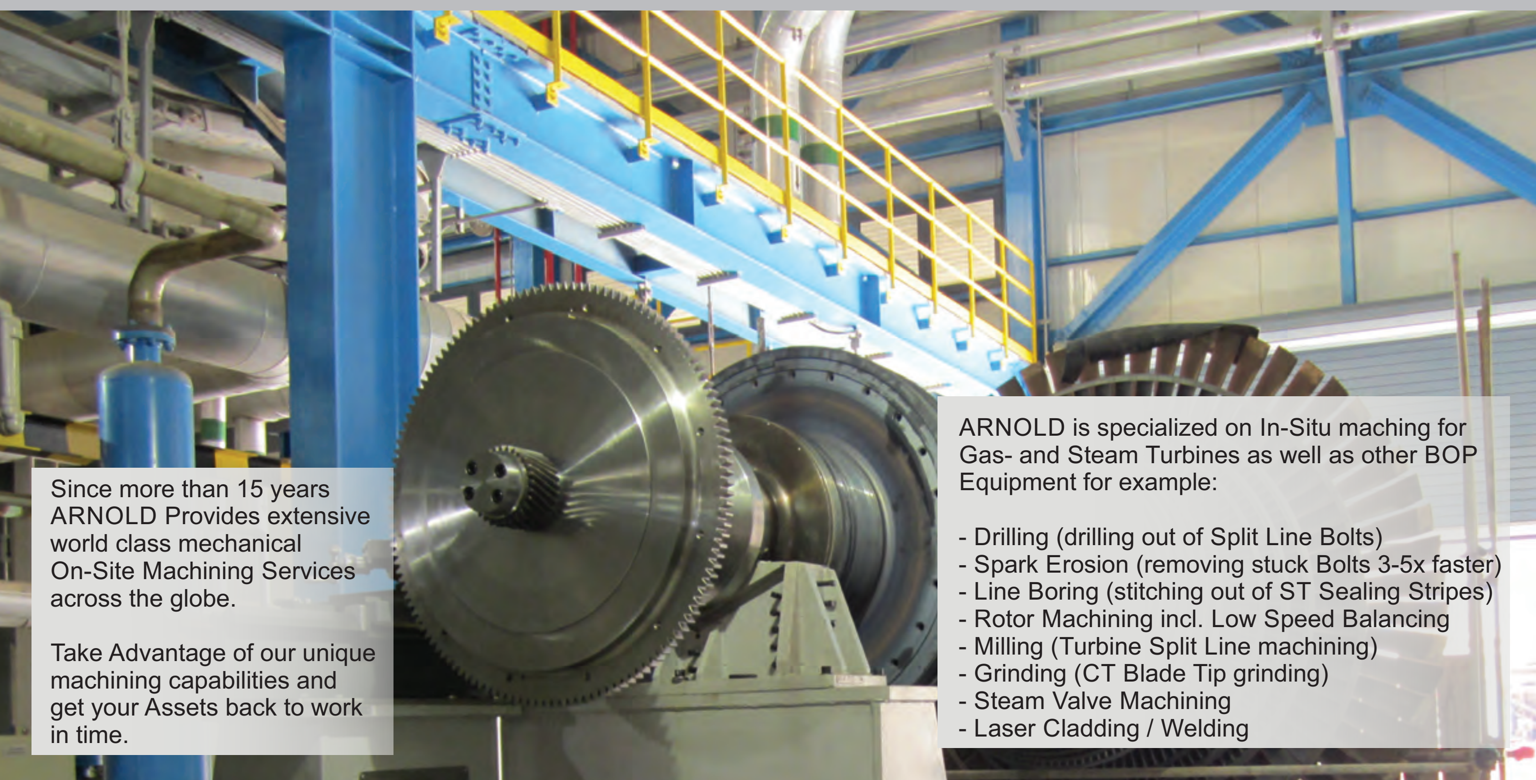
Mechanical On-Site Machining Services



Milling
(e.g. Split Line)

Rotor Machining
(e.g with Low-Speed Balance)

Valve Machining
(e.g. Governor Valves)



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Black Point Power Station

Owned by Castle Peak Power Co Ltd
Operated by CLP Power Hong Kong Ltd

3850 MW, gas-fired with ultra-low-sulfur diesel backup, eight 337.5-MW 1 × 1 combined cycles powered by GE 9FA.03 gas turbines (a/k/a C units), plus one 550-MW and one 600-MW 1 × 1 combined cycle powered by Siemens-Energy 8000H gas turbines (a/k/a D units). The units were installed in phases from 1996 to 2024. Location: Hong Kong's New Territories

Plant manager: Kwok Keung Luk

Operational excellence in outage management

Background. CLP Power Hong Kong Ltd (CLP Power) operates a vertically integrated electricity supply business that serves more than 80% of Hong Kong's population. The company is regulated under a so-called Scheme of Control (SoC) Agreement by the government of the Hong Kong Special Administrative Region (SAR), which monitors the company's operating performance and financial affairs.

Under this agreement, CLP Power has an obligation to supply sufficient and reliable electricity to its service areas at a reasonable price and in an environmentally responsible manner.

Black Point Power Station (BP), a gas-fired combined-cycle facility, originally comprised eight GE 9FA.03 gas turbines commissioned between 1996 and 2006. In response to supply/demand and climate-change challenges, all eight units were upgraded to increase their efficiency and capacity.

In support of the Hong Kong SAR government's environmental policy and the transition from coal- to gas-fired generation, CLP Power added two more 1 × 1 combined cycles, one each in 2020 and 2024, increasing the proportion of gas-fired generation in its fleet to around 50%. With these Siemens-Energy 8000H machines, BP now boasts a total generating capacity of 3850 MW across 10 units

Challenges. BP's 10 combined cycles require about 10,000 man-days of work in a single outage season (from September to May of the following year), an effort involving around 700-800 in-house CLP O&M personnel and contractors. Managing and completing all planned outage work in a safe, effective, and timely manner presents major challenges in outage planning, execution, and management, as outlined below:

1. Shortage of competent local labor.

A limited local labor supply presents substantial challenges during outages requiring a skilled workforce to effectively conduct powerplant maintenance and upgrade work. The shortage of qualified workers in Hong Kong for tasks such as those requiring high-pressure welders, crane operators, scaffolders, etc, constrains resources during outage execution.

The scarcity of competent labor can be attributed to several factors—including an aging workforce, cost and difficulty in arranging labor import, and heightened demand for technical expertise in the local market because of existing or future large infrastructure projects.

2. Significant difference in manpower and resource requirements between peak and trough periods. Consideration must be given to the possibility of conducting outages for multiple units simultaneously. Also, given that most of the gas units have very high utilization hours, a large portion of the maintenance work can be done only during planned outages.

For these reasons, a surge in manpower and resources often is experienced during outage periods compared with times when most units are operating and little maintenance work can be done.

Balancing the fluctuation in manpower and resources can be quite challenging to the outage management team because CLP Power and its contractors must minimize retention cost during the low season to remain competitive. Cross training employees to handle multiple roles, and work levelization during outages, are among the ways to promote operational excellence.

3. Plant aging issue, given BP units are reaching mid-life. More unexpected and significant defects are being identified on critical plant equipment, indicating that the existing maintenance strategy is insufficient to maintain equipment reliability to the level expected. Plus, outage execution has become more complex because of the upgrade projects required to maintain desired reliability.

4. Differences in work culture and behaviors between CLP and contractors. Multiple work parties with diverse languages and work cultures are to be expected in today's outages. The ratio of newcomers to experienced personnel also is higher than in the past. Additional coaching, guidance, and supervision are required to ensure productive, high-quality, and safe implementation of outages.

5. Very limited outage windows for BP generating units. Compressed work schedules are required to meet outage deadlines and maximize unit availability to meet summer demand. Overlapping of unit outages causes conflicts between resources required for different outages and increases the complexity of planning and coordination—especially because schedule delays are unacceptable.

Solutions and results. To ensure a successful outage, six initiatives were introduced to achieve operational excellence. They were driven through the organization's hierarchy by management and focused on


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implementation of best practices and continuous-improvement initiatives to enhance outage planning and resource allocation and execution. The six initiatives are:

- Early outage preparation.
- Manpower planning.
- Pre-outage communication and engagement.
- Short-interval control.
- Communication of lessons learned.

Early outage preparation

Outage planning. An excellent unit outage starts with early and detailed planning. To ensure safe and smooth outage execution, thorough preparation of the outage program, work schedule, manpower resources, spares and materials, tools, and equipment are essential.

Driven by an initiative to achieve operational excellence, a comprehensive outage planning management system was enhanced to guide the outage team. It covers all projects and preventive maintenance (PM) and corrective maintenance (CM) work to be implemented during planned outages (PO). This management system aims to achieve the following:

- Allow early identification of potential risks in outage execution.
- Establish effective mitigation measures.
- Ensure clear communication and coordination among all stakeholders.
- Facilitate safe, smooth, and well-controlled execution of all outage work.

The outage planning management system specified a clear timetable to freeze outage work scopes and resources thusly:

- Nine months before outage start: Freeze project work list.
- Six months before outage start: Verify funding of all projects.
- Three months before outage start: Freeze PM work list; ensure resources planned for all projects are available; verify resource plan for all PM work.
- One month before outage start: Freeze CM work list; ensure the resource plan for all CM is ready.
- Two weeks before project start: Freeze outage master schedule.

Result. Effective management of outage-execution readiness is verified by use of an outage scorecard and traffic-light mechanism.

The scorecard provides comprehensive information to allow an overview of unit-outage execution readiness in terms of outage work scopes, project funding, work schedule, resource planning, and availability.

The traffic light helps to point out critical outstanding issues which may incur significant impact on outage commencement or implementation, allowing early awareness for the outage management team to take necessary mitigation measures.

Change management in outage execution. Changes in work scopes occasionally are required, even for a well-planned outage. Since the project and PM work lists have been finalized and frozen well before the outage starts, it is necessary to have a clear mechanism in place to ensure all changes to outage work scopes and/or schedules are manageable and all stakeholders are notified to allow sufficient time for coordination and adjustment of resources.

Result. The change management system helps the outage management team consolidate and evaluate resource and interfacing issues that may arise from the change. Such analysis is reported to the outage steering committee for approval with justification. This mechanism provides flexibility and the ability to align the latest outage plan, if necessary, while safeguarding the outage execution feasibility after the change. Information included: Change details, justification, proposed start/finish dates, and impact of change (material, contractor resources, equipment, funding, quality, and schedule).

Outage standard time optimization. Given the limited outage window, staff actively reviews outage standard time, especially for critical-path activities, using data collected during outage monitoring activities. Common work steps of unproductive time are identified and strategies are developed to eliminate or minimize them. Outage personnel collaborate closely with the maintenance team to reassess the work program and identify opportunities for resequencing or paralleling tasks to expedite outage completion (for example, a two-shift work arrangement for critical-path activities). These efforts help maximize resource utilization and reduce overlapping outages.

Result. As of April 2024, optimization progress was positive with three-quarters of the major work having been reviewed during the 2023/2024 outage season. This resulted in an 83-day reduction in outage time for 2024/2025 compared to the previously approved work plan, which, in turn, was 25% less than the next earlier approved version.

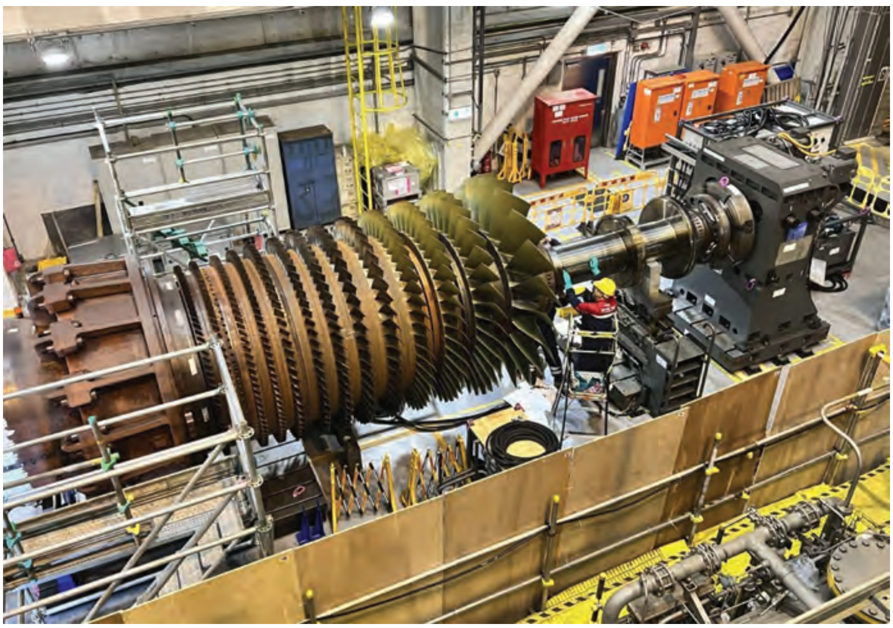
Manpower planning

Because an overlapping of unit outages in 2023-2024 was foreseeable, an early review of operational manpower was conducted in October 2022 to ensure sufficient competent personnel would be available to support unit isolation, de-isolation, restoration, testing, and commissioning activities.

Result. The critical, most manpower-intensive period was identified, and an assessment conducted to determine the corresponding operational manpower requirement. As a solution, a team of outage operating engineers was established to support parallel unit outages by using a "flexible-team" arrangement across the BP units and Castle Peak Power Station, another CLP generating plant. Additionally, an early start to on-the-job training was arranged to increase the technical competence of young engineers.

The staffing requirement for each C unit (GE 9FA) was one senior shift engineer and two shift engineers at outage start and outage end, and two shift engineers in the middle of the outage; for each D unit (Siemens-Energy 8000H), one senior shift engineer and four shift engineers at outage start and outage end, and one senior shift engineer and three shift engineers in the middle of the outage.

During overlap periods—D unit start and C unit end—two senior shift engineers and four shift engineers are required; plus, one



1. Siemens-Energy 8000H powers the combined cycles for Black Point Station 2

Castle Peak trainee and one graduate trainee on shift. Note that Castle Peak has coal-fired units in addition to gas/oil-fired gas turbines.

During the manpower planning stage, personnel requirements for different work scopes are reviewed (for example, high-pressure welder, crane operator, rigger, etc) to ensure outage progress will not be compromised by a shortage of staff with a particular skillset.

Additionally, project managers are responsible for reporting the status of work-permit applications in case onsite support by a foreign expert or advisor is required. This review assures sufficient manpower to complete the outage, and if gaps are identified, there's sufficient time for making adjustments.

Result. During planning for the Unit D1 outage, management identified the need for more shift engineers. The issue was resolved by arranging three engineers from the outage management team to support in nighttime shift-work supervision.

In addition to alleviating the stringent manpower resources, this arrangement provided a good opportunity for honing the skills of outage team members regarding the 8000H gas turbine (Fig 1). Through hands-on experience and inspection of daily tasks, team members were able to expand their knowledge and provide timely updates on outage progress.

2. Trial lifts of critical components (GT rotor at left; exhaust casing at right) are an important part of pre-outage training

Pre-outage communication, engagement

Prior to the outage, it is essential to coordinate with the main contractor and relevant stakeholders to review and acknowledge the safety measures and job arrangements on major activities and critical tasks. This helps to align expectations of various work forces within the outage for both the site management team and the frontline workers.

Result. Several training sessions were provided for engineers and workers to deliver SHE (safety, health, and environment) standards and requirements for working in unit outage areas. This training was designed especially for newcomers who had no prior work experience and were not familiar with the SHE requirements for CLP Power stations. The goal was to improve safety awareness prior to outage start.

To ensure the safety message was well received by the personnel involved, some critical work packages were selected to test their understanding. For example, the gas-turbine upgrade project requires frequent heavy lifting of engine components, which involves complex handling operations.

Trial lifting of the gas-turbine rotor (Fig 2 left) and flipping of the exhaust casing

(Fig 2 right) were performed to review the effectiveness of the lift plan and ensure all safety measures are being observed. A post-trial briefing was conducted for findings observed during the trial to ensure understanding and the drive for improvement.

Pre-outage inspection to fine-tune outage scope

To ensure all units can perform with high availability after a planned outage, and to minimize the forced-outage rate, it is important to identify hidden defects beforehand—thereby minimizing unexpected work during the outage which might delay the unit's return to service. Through operational excellence, the pre-outage inspections drive and enable early assessment of the unit to achieve the following:

- Enhance understanding of current plant condition and facilitate early decision-making of the planning and preparation for necessary maintenance work.
- Reduce work-scope uncertainties during outage execution (for example, unexpected critical plant defects or equipment failures identified).
- Ensure readiness of tools, materials, and manpower for maintenance work—preventing undesirable extension of the outage period due to resource unavailability.

Result. Two 17-day planned outages were scheduled for Units C3 and C4 in March and April (2023), respectively. The major activities in these outages focus on HRSG statutory inspection. Based on experience, it is common to identify unexpected defects in the HRSG during the inspection process. Staff encountered difficulties in preparing sufficient materials, tools, and manpower to fix those unexpected defects.

To mitigate these issues, two pre-outage inspection and maintenance outages (MO) were arranged and a boiler internal inspection by drone was conducted. During the pre-outage inspection, several internal defects were revealed.

With clear and sufficient information on HRSG internal condition, the CLP Power maintenance team and contractor were able to update and fine-tune the work scopes for the planned outage. The bottom line: Planned outages were completed successfully within the original planned window with all additional HRSG internal defects repaired.

Short interval control

The first implementation of short interval control (SIC) for onsite supervision and monitoring in 2023 contributed significant improvement to site inspection and overall performance. SIC is a structured process that brings insight into identifying opportunity times for improvement and managing site safety, productivity, and quality performance—thereby enabling instantaneous actions to improve effectiveness and efficiency of activities and processes (Fig 3).

Regular site visits by CLP Power's responsible officer (RO) and the contractor's engineer-in-charge (EIC) can strengthen construction site management and directly instruct contractors on the owner's requirements. Direct and timely supervision can effectively deliver the utility's work expectations.

In each site check-in, the RO assures active supervision to provide the following:

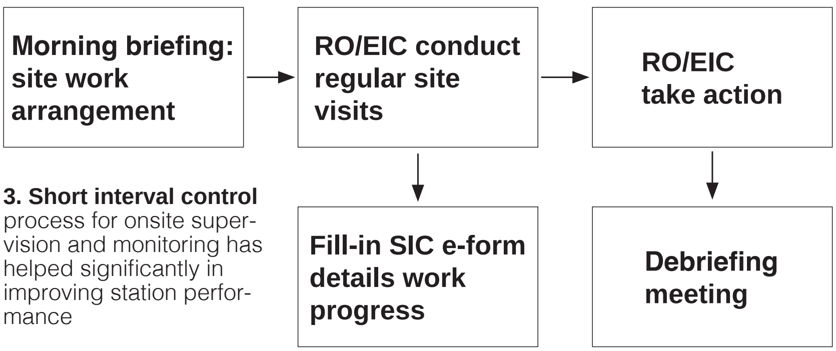
- Timely calibration on site management.
- Seamless cooperation with contractors to address unforeseeable issues.
- Regular site performance records for analysis.

The direct benefits of SIC include empowering the RO to maintain adequate control and understanding of construction-site condition. When necessary, the RO can take immediate action to ensure effective site management. Any issues that arise during site checks are meticulously recorded and used to promote continuous improvement.

As the SIC process evolved from mere compliance to general use, it has played a crucial role in shaping the mindset of both the RO and contractors regarding effective site management. By bridging cultural and behavioral gaps that are aligned with CLP's expectations, this process enhances the competencies of both parties.

Insights and observations derived from SIC undergo a thorough root-cause analysis (RCA). Lessons learned and action items to address identified issues are registered and communicated to both the RO and contractors via a pre-outage communications program. This proactive approach enables the outage management team and different working parties to make necessary preparations for any foreseeable risks in upcoming work.

With SIC implemented, ROs and EICs are required to proactively supervise work and capture the safety, quality, and productivity performance of site activities. An "SIC App" using "Power Apps" has been developed using the "Power Automate" platform for users to submit site observations for every job. The application streamlines processes by recording work planning data automatically



3. Short interval control process for onsite supervision and monitoring has helped significantly in improving station performance

and creating a database for all observations onsite while facilitating data analysis by the outage management team.

This analysis is used to facilitate discussions in the management control system as well as with the contractor management team in its drive for work ownership and continuous improvement.

Result. The effectiveness of SIC implementation has been monitored closely since its launch. Staff has found that the quantity of SIC submissions significantly increased during the outage season (October to April), indicating a higher level of work ownership on both the CLP in-house maintenance teams and contractor teams (Fig 4).

Numerous areas of improvement, which CLP calls "opportunity time" also were identified to improve outage performance in terms of productivity, quality, and safety. Since January 2024, an increasing trend of good observations also was reported through SIC exercise, revealing a positive change in the mindset and working behaviors of different contractor teams.

To achieve operational excellence, more support, guidance, and coaching from CLP Power was provided to selected contractor EICs and site supervisors, allowing them tighter control of the workforce and the ability to address productivity issues by taking immediate actions onsite. Productivity and quality of work improved accordingly.

Result. During a recent Unit D1 outage, the day and night shifts were scheduled to speed-up progress on critical-path activities; ROs were assigned shift duties to monitor work performance and progress. Past experience had indicated that a reduction of supervisory personnel during night shifts led to more relaxed behavior and lower productivity among contractors.

SIC process observations provided valuable findings into the specific items that had to be addressed, thereby enabling follow-up to rectify issues and improve overall performance.

Example of a productivity issue identified and improved at an early stage of the outage: Multiple SIC observations by RO reported that a contractor work team was not present from 11:30 p.m. to 1:10 a.m. for its meal break and also left the site at around 6 a.m. for an 8 p.m. to 8 a.m. shift.

CLP Power raised the issue with the contractor's representative in a weekly RCA meeting and requested that the company provide the work team clear instructions regarding the need to return on time after meal breaks and to remain working onsite until at least 7 a.m. The resulting improvement enabled early commissioning.

In 2023, three of seven Black Point unit outages were completed successfully in fewer days than expected thanks to SIC support. The remainder of the outages were completed on time.

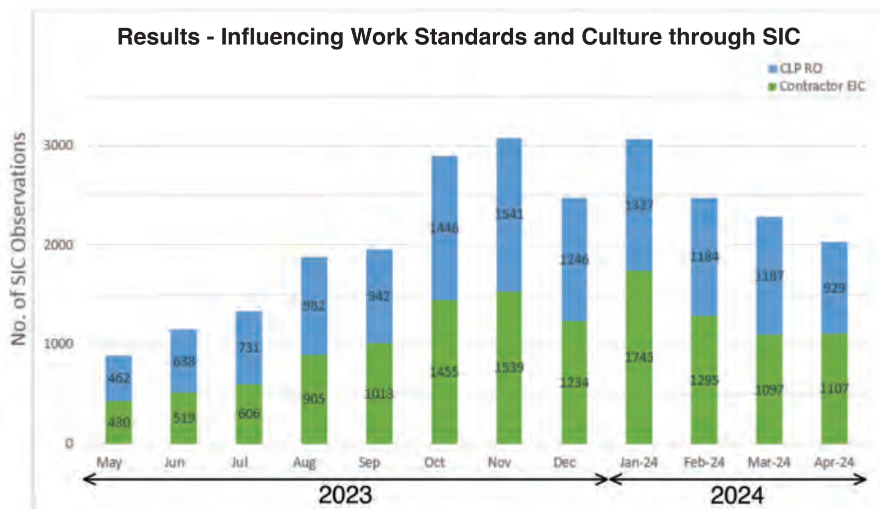
Lessons learned

- Lessons-learned register. SIC findings with actual onsite work progress, deviation with work plans, and any other issues observed during the outages were captured using an application developed by in-house staff. A register also was established to track and analyze all findings. RCA meetings are conducted with working parties weekly to address issues and ensure timely improvements and immediate follow-up actions.

- Post-outage focus groups are collaborative forums that dig into significant or repetitious major outage issues or incidents. Key stakeholders are selected to review existing practices and propose improvement actions. By sharing perspectives and insights among the key parties, areas for improvement are identified and they act as a driver for systematic changes in future outages.
- Engagement sessions share the outcomes of the discussion groups. They ensure collective understanding and engagement while encouraging feedback and suggestions from the larger group. This allows for alignment of outage management practices and ensures all stakeholders are engaged to support the proposed changes in future outages. It creates an atmosphere for a learning organization and empowers all stakeholders to own and contribute to the success of future outages.

Result. The D1 outage started in late February 2024 and the critical-path activity was the hot-gas-path inspection for the Siemens-Energy gas turbine. According to the engine log, the D1 had experienced an incident during an earlier combustion inspection and boiler statutory inspection outage. The follow-up investigation team identified that the incident was caused by fuel-oil leakage during a fuel-transfer commissioning test.

As an improvement action, CLP Power established quality check sheets to verify the integrity and condition of the gas-turbine fuel-gas and fuel-oil systems after restoration from unit overhaul. Additionally, the acceptance standard for torque checks on fuel-oil and gas pipes also were reinforced to ensure high-quality outage work.



4. SIC implementation is closely monitored

End notes

By learning from the challenges and pitfalls encountered in previous outages, plant personnel developed effective solutions to enhance outage management. Implementing comprehensive planning, emphasizing communication and coordination, and prioritizing work contribute to successful outage execution and improved performance. CCJ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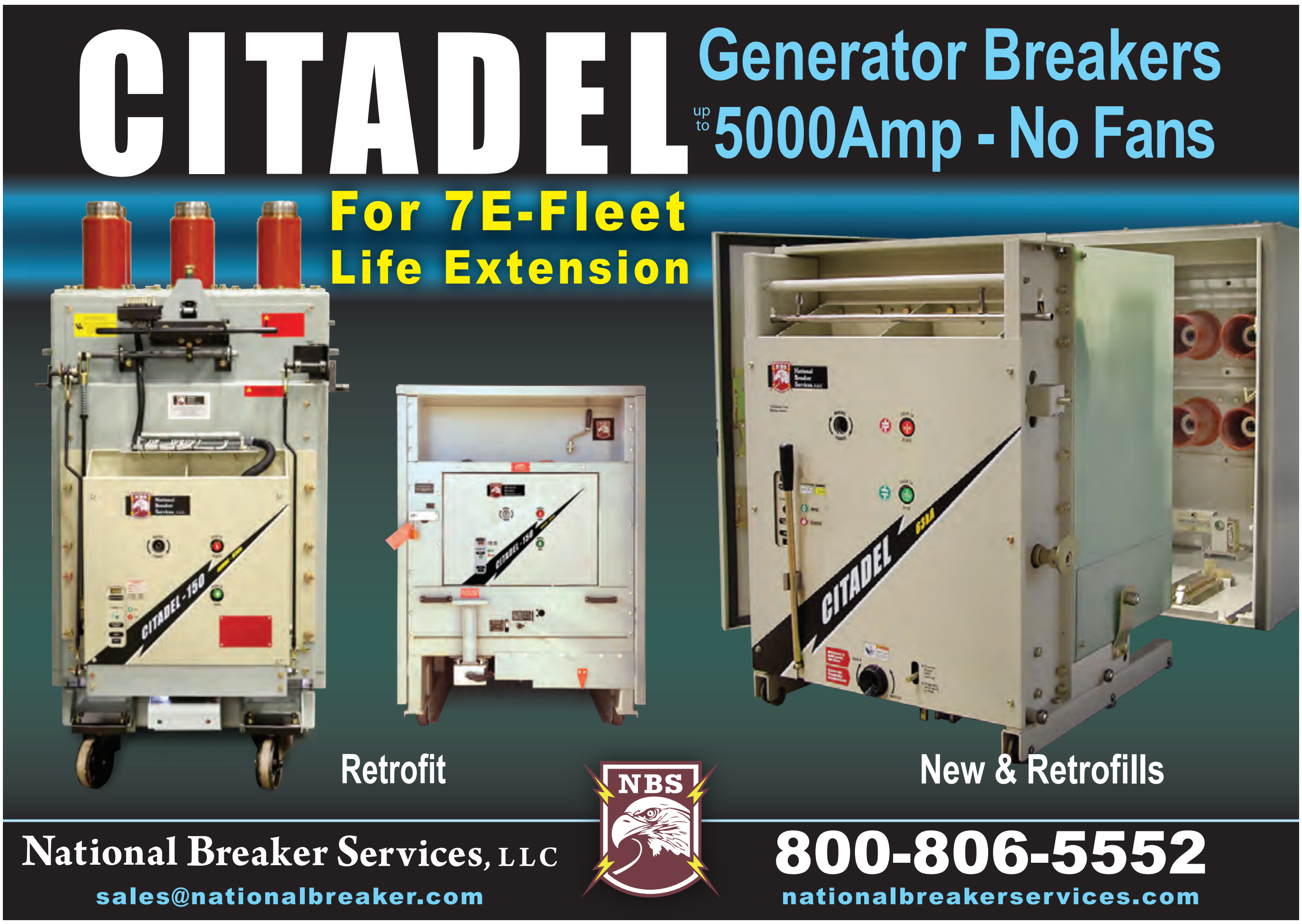
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7 EA GACs Have Insulator Problems!

Crown-sulators

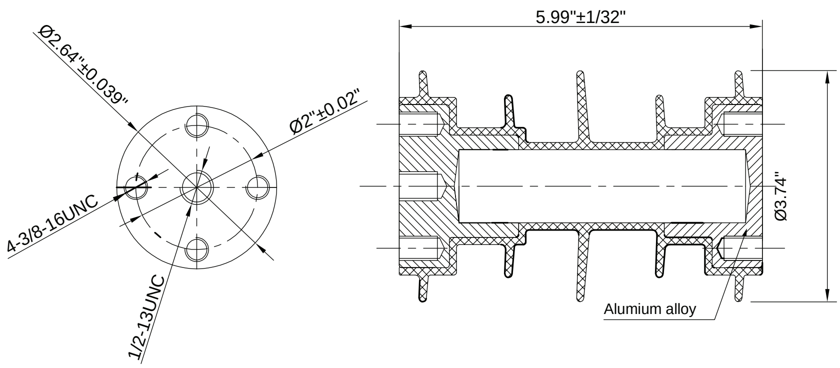
provide a bolt for bolt solution

Technical specifications:	
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 strenth	2900in-lbs
Min creepage distance	11.8inch
Acring distance	6.14inch

The color of weather sheds is light gray

Standard applied: ANSI C 29.1

2.5lb



Crown-Sulators and the "Drop Test" Video link

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Fabricators to the Utility Industry

Hill Top Energy Center

Owned by Ardian Infrastructure, Ares Management Corp, and Menora Mivtachim
Operated by NAES Corp

620 MW, gas-fired (with ultra-low diesel backup) 1 × 1 7HA.02-powered single-shaft combined cycle with a GE steam turbine/generator and heat-recovery steam generator, located in Cumberland Twp, Greene County, Pa

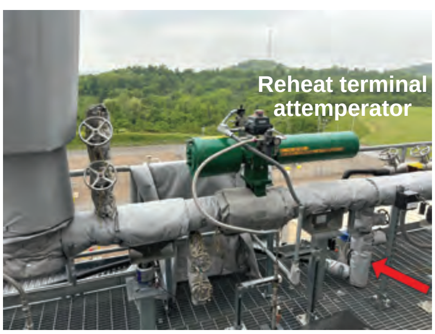
Plant manager: Pete Margliotti

Attemperator freeze protection

Challenge. The three attemperator systems serving Hill Top Energy Center's heat-recovery steam generators are located in the plant's upper-most pipe rack and exposed to extreme weather conditions—including high winds and low temperatures (Fig 1). Although the boiler feedwater supply lines that provide attemperator spray water to these bypass systems are heat-traced and insulated, staff elected to add a secondary means of freeze protection by addition of continuous-flow/leak-off lines upstream of the attemperator control and block valves (Fig 2).

These valves are located at the furthermost downstream ends of their respective pipe runs, thereby allowing water in the lines to lay stagnant when the station is online and in normal operation.

Stagnant water, plus the possibility of power loss to the heat-trace system, created additional concern for freeze potential when the unit is operating. The attemperators are required during a unit trip/shutdown; thus, if the lines freeze up it is not possible to attemperate steam flows bypassed directly to the condenser in a startup or shutdown scenario.



1. Attemperator systems are located in the upper-most pipe rack and exposed to high temperatures and high winds

Solution. The attemperator lines, supplied by the boiler-feed pumps, are 3 or 4 in. in diameter, depending on the application. Continuous flow through the attemperator lines was made possible by installing ½-in. Weldolets in the attemperator supply lines (Fig 3) to provide a slip stream of 1-2 gpm of boiler feedwater to circulate through the supply lines. Flow control is by two ½-in. globe block valves and one ½-in. full-port control valve.

In normal operation, the two block valves are aligned in the open position and the control valve is shut until ambient temperature is below freezing for a period. At that time, the DCS signals the control valve to open and allow flow.

Immediately downstream of the control valve, each ½-in. heat-traced leak-off line is equipped with an orifice. Its size is based on the boiler-feed water pressure at the location. The nominal 200-ft-long leak-off lines route their respective slip streams to the turbine drains tank where they are collected for return to the condenser.

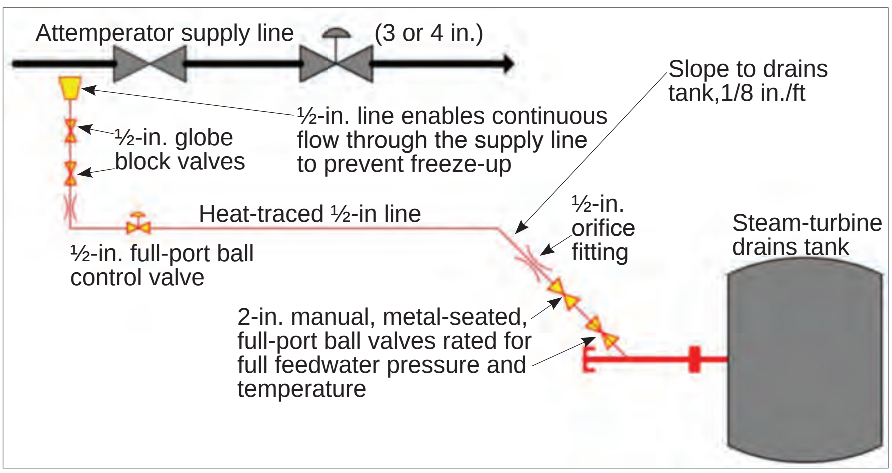
Additionally, ahead of the steam-turbine drains tank, a second orifice was installed and sized to apply proper backpressure to ensure the leak-off water does not flash to steam in the ½-in. line on their way to the drains tank.

Important to note is that just ahead of the orifice, pipe size and material were changed to 2-in.-diam P22 to allow for a flash area prior to gravity draining to the tank (Fig 4). Lastly, double-block 2-in. globe valves were installed in the flash area to enable drain-line isolation for future maintenance.

Note, too, that the ½-in. drain lines are supported by a cable tray sloped 1/8-in./ft in the direction of the tank. Also installed: A 480-V stepdown transformer and power panel equipped with individual isolation breakers (Fig 5). An RTD was placed near the pipe rack to provide a signal for on/off activation of the heat-trace systems serving the drain lines. Power indicating lights were installed at the ends of the drain lines to facilitate monitoring.

Results. The system has performed as intended; there have been no freeze-up issues.

Project participants:
Jon Mongold, maintenance manager



2. Continuous-flow/leak-off lines were installed to provide a secondary means of freeze protection

Comparing compressor-wash rinse conductivities for competing soap products

Challenge. Selecting the most effective soap for cleaning your gas-turbine compressor.

Solution. Maintaining gas-turbine compressor performance at a high level is essential for achieving acceptable combined-cycle output and efficiency. Reliable performance of the compressor water wash system is especially important in this regard. Central to the effectiveness of a water wash is the type of soap used, which should be in accordance with the OEM's guidelines—such as quantity, flow rate, and other variables.

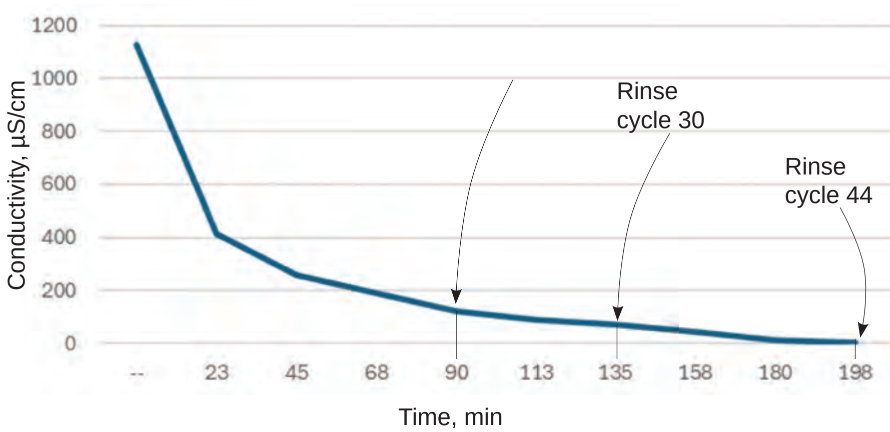
Results. Factors to consider when selecting a soap include gas-turbine power recovery and rinse times and cost. Top Hill Energy Centre found that switching to Rochem's FyreWash F2 product had a positive impact on its operation. Comparison of rinse conductivity versus time for the two products compared are presented in Figs 6 (before) and 7 (after).

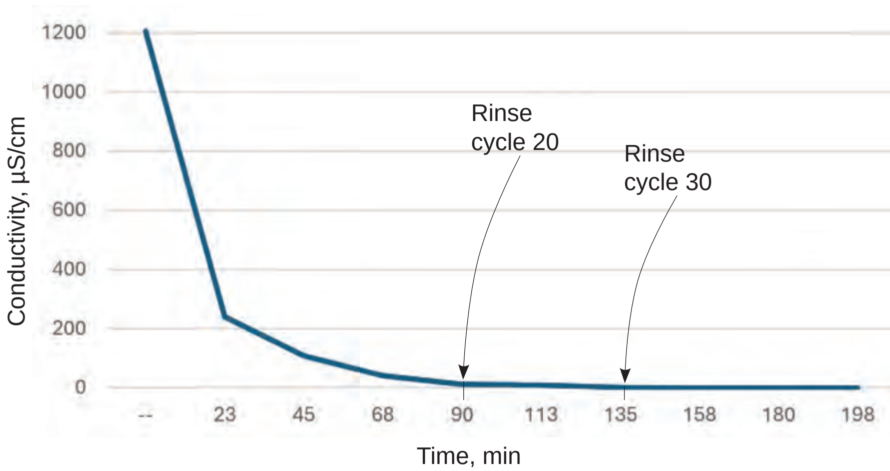
The product the plant had been using recovered 3.1 MW (corrected for ambient conditions) from the wash, conducted July 2023 using 32 gal of soap; 4.3 MW was recovered (corrected for ambient conditions) by washing with 36 gal of FyreWash F2 in April 2024. Number of rinses for the first test was 44, for the second, 30.

3. Installation of ½-in. leak-off line into attemperator supply line

4. Welding of 2-in. P22 Latrolet fitting for tie-in to existing steam-turbine drains-tank line

5. Electrical equipment to enable freeze protection included disconnect, step-down transformer, sub panel, and control panel





6, 7. Results of rinse conductivity versus time using "standard" industry soap are in the top chart, those for FyreWash F2 are at the bottom

Indeck Niles Energy Center

Owned by Indeck Energy, KOSPO USA, and DL Energy
Operated by PIC Group Inc

1085 MW, gas-fired 2 × 1 7HA.02-powered combined cycle with a GE 602 steam turbine and Doosan heat-recovery steam generators, located in Niles, Mich

Plant manager: Kevin Kringle

Digital visitor management system contributes to workplace safety

Challenge. Indeck Niles Energy Center was not equipped with an emergency notification system to alert individuals onsite during a system-wide event. The number of plant personnel onsite averages 14 or fewer daily, with contractors adding perhaps more than 100 individuals per day during outage maintenance events. Given the plant's size and the number of contractors onsite, staff is not able to issue radio equipment for each individual.

There is added difficulty in managing multiple types of documentation for site visitor logs, Covid-19 screening questionnaires, completion of site safety orientation, facility blacklist of banned personnel, and maintaining an active head-count of individuals coming and going each day (Fig 1).

Solution. MRI OnLocation, a flexible software solution for managing visitor information in real time, allows for site-specific screening questionnaires, tracking of facility head-counts for muster emergencies or evacuations, completion tracking of facility safety orientation, and blacklist of people banned from the site.

Most notably, the platform sends out live SMS notifications to all personnel on the property in the event of an emergency and provides instructions/protocols simultaneously for the facility. The platform's OnEvac mobile app is configured for use in the event of an evacuation for a manual roll call of personnel onsite via SMS or phone call. Platform administrators send out automated "Are you safe" requests to all users with cellphone numbers saved to their profile.

Use of this system allowed for safe social distancing practices during Covid-19 mitigation efforts site-wide. The OnLocation platform offered touchless entry and exit, and pre-screening questionnaires as needed.

The platform is web-based, and it provides constant traffic counting for entry and exit points assigned to the facility.

Plus, the platform maintains an indefinite digital log for the facility, which can be referred to for contact tracing, labor timesheets, and incident reporting at any time. This aids to manage the health and safety of both site employees and contractors/visitors from a single platform.

Results. OnLocation eliminated the need to manage multiple programs for each person coming and going from the site. The system is entirely cloud-based, so it does not take up any additional memory space on facility network computers or hardware.

A site-specific QR code generated by OnLocation is printed and posted at facility entry points and replicated as needed. An automated kiosk can also be used via laptop, tablet, etc, for designated visitor check-in areas (Fig 2).

Multiple entry and exit points can be configured without any limitations on quantity for each facility. QR codes can be updated and regenerated as often as desired for an added layer of security. QR code posters are highly customizable to include site-specific logos, colors, or labels as required.

Employees hosting a visitor automatically receive a notification of the visitor's arrival, once he or she has completed facility check-in. Notifications are sent directly to employees via email or mobile phone number. After initial visitor entry, OnLocation will remember and store that individual's profile for future check-ins.

OnLocation also generates reports of people present for administrators, which can be exported via PDF or CSV files. Additional features include grant/deny access, acknowledgment notices, and printing of badge passes upon arrival for a visual verification of sign-in process completion status. Facility administrators also can set maximum occupancy rules for automatic notification of thresholds reached.

Installation time for OnLocation was minimal, with significant cost saving as opposed to purchase of a site-wide PA system or radio rental contract. This has greatly contributed to overall workplace safety, security, and communications at Indeck Niles.

Project participants:
Cora Cook
Kevin Keiper
Gregory Winters

1. OnLocation maintains an active head-count of individuals coming and going each day

2. Automated kiosk serves in designated visitor check-in areas

Long Ridge

Long Ridge Energy Generation

Owned by Long Ridge Energy & Power
Operated by NAES Corp

485 MW, gas-fired 1 × 1 7HA.02-powered combined cycle capable of burning between 15% and 20% (vol) of hydrogen today, located in Hannibal, Ohio

Plant manager: Chris Bates

Denison survey helps improve employee morale

Background. The culture of Long Ridge Energy Generation stresses the importance of preserving employee strengths as well as continuous improvement. One area requiring consistent monitoring is that of employee morale. Management decided to gauge the overall morale of the team by administering the Denison Organizational Culture Survey and using the results to make necessary changes.

Challenge. Employee morale will always be a major contributing factor to an organization's success. After almost three years at Long Ridge Energy Generation, the management team wanted to see what could be done to improve morale and ensure employees were satisfied with the plant's culture.

Solution. A Denison Organizational Culture Survey was conducted to receive feedback from employees on the way the Long Ridge organization operates. Once the surveys were completed, multiple sessions were held to share the results and create an action plan to make several recommended changes.

Results. The feedback received from Long Ridge staff (Fig 1) was used to make changes in policies, alter the way daily affairs were managed, and contribute to implementing new practices. The overall morale of the plant has improved. The Denison survey will be conducted again for comparison purposes and to see if additional changes are necessary

Project participants:
Brandi Hobbs, administrative manager

Mod improves reliability of water treatment system

Background. Long Ridge Energy Generation uses an onsite facility to treat water pulled from the Ohio River, the plant's primary source of cooling water. The water treatment facility must be functioning properly for the plant to operate.

Challenge. The water treatment system was unreliable and maintenance on that facility could not be performed while the plant was operational. Long Ridge was forced to find another source of water when the water treatment facility was down or needed maintenance.

Solution. An employee with prior experience in the oil and gas industry recommended using aboveground storage tanks

1. Employee morale is a major contributor to operational success at Long Ridge

7HA HEAVY DUTY GAS TURBINE

Outstanding Combined-Cycle Efficiency:
>64% for Reduced Customer Carbon Footprint

290-430 MW
Simple-cycle output

438-640 MW
1×1 Combined-cycle output

880-1,280 MW
2×1 Combined-cycle output

64%
Combined-cycle efficiency

60hz

9HA HEAVY DUTY GAS TURBINE

Outstanding Combined-Cycle Efficiency:
>64% for Reduced Customer Carbon Footprint

448-571 MW
Simple-cycle output

680-838 MW
1×1 Combined-cycle output

1,363-1,680 MW
2×1 Combined-cycle output

64%
Combined-cycle efficiency

50hz

Our HA fleet stands as our most advanced, reliable, and efficient product line—proven across a wide range of global installations. From flexible grid support to high-efficiency combined-cycle applications, the HA has earned the trust of the world's leading energy providers. And as demand for lower-carbon, high-performance power grows, we're continuing to invest in its future. That's why we're committing $160 million to expand our Greenville, South Carolina factory—boosting manufacturing capacity, supporting job growth, and ensuring we can deliver with speed, scale, and confidence.

121
Operating units

135+
Customers

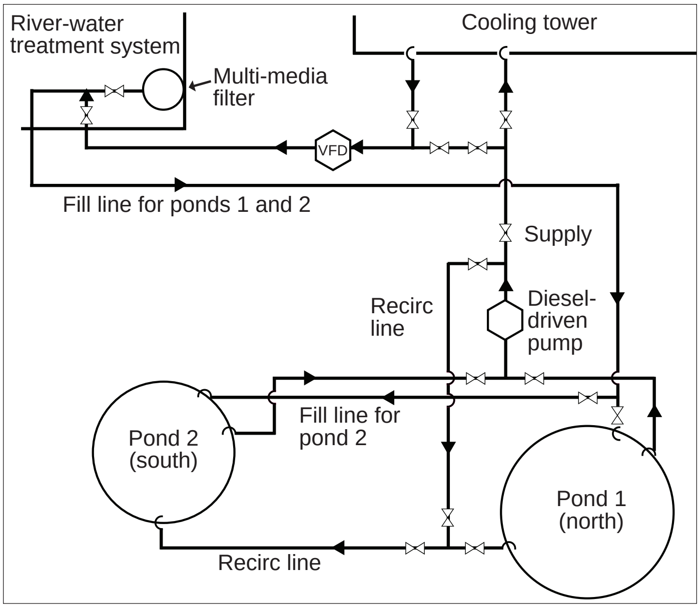
3.3M
Operating hours

7HA

9HA

Investment

GE VERNOVA



2, 3. Cooling water for Long Ridge is pulled from the Ohio River, treated, and retained in two ponds that serve the cooling tower

(a/k/a ASTs) as a solution (Figs 2 and 3). Onsite equipment was used to fill the tanks with treated water and infrastructure was installed to pump it to the cooling tower.

Results. The ASTs allow the plant to continue operating if it cannot produce useable water with the treatment facility. Plus, the ASTs serve as a backup when the treatment facility requires maintenance.

Project participants:
Logan Ensinger, control room operator

Circ-water system reliability upgrade

Background. Long Ridge uses a circulating water system from the cooling tower to serve both the main condenser and auxiliary equipment. It is comprised of two 50%-capacity pumps plus two inlet and two outlet valves to control flow to the condenser. These valves are used during system startup and shutdown to throttle and create backpressure to keep the pumps running on their designed operating curves.

Challenge. The inlet and discharge valve actuators were experiencing internal electrical component failures which resulted in "bad quality" for DCS and local display indication. This required the auxiliary operator to control the valves locally to establish conditions for starting the system. Staff determined these failures were caused by extreme vibrations attributed to the length of the valve stems used to interface with the valves.

Solution. Long Ridge contacted the valve manufacturer's local rep to discuss options for remediating the issue. One option was a conversion kit that could be installed by plant technicians. It allowed remote mounting of the electronic controls that provided the same functionality as the original installation (Figs 4 and 5). The initial mod was performed on the ground-level inlet and outlet isolation valves.

Results. No failures have occurred since the first mod was completed. Plan is for the remaining valves to be modified at the next opportunity.

Project participants:
Victor Jackson

4, 5. Vibrations that compromised operation of valve actuators were mitigated by remote mounting of electronic controls (before/after are at the left/right, respectfully)

LEGACY TURBINE FORUM, NO. 5 IN A SERIES

How the GT exhaust-thermocouple correction coefficient came to be

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

Editor's note. This article is based on material presented by the author in his training courses on gas- and steam-turbine controls to explain the reason for the algorithm described and how it works. Email clukewilliams@mindspring.com and ask to be notified of his upcoming controls training courses for GE aero and frame gas turbines.

With the introduction of the Mark IV digital control system, the calculation and display of thermocouple (t/c) input signals is done entirely by the processor—including cold-junction/short-circuit compensation, conversion of the millivolt signal to temperature, and open circuit biasing.

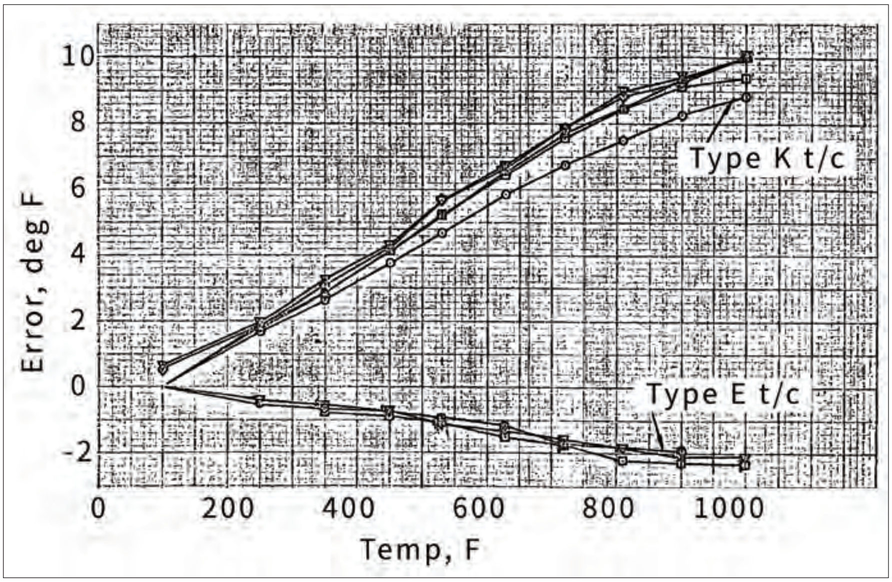
There was a perceived need to be able to "adjust" the temperature signal for hardware inaccuracies. The "adjustment" feature would be hidden to avoid confusion with the TTKX temperature control constants. A control constant, TTKXCOEF, was added to the temperature algorithm, scaled as a decimal. The range was 0.000 to 1.000.

Calibration verification of thermocouples in 1981 indicated that approximately half had quality problems, including failure to meet accuracy specifications. Further investigation determined that for a group of 25 new t/cs, the average reading was 5 deg F above calibration, ranging from 2 to 19-deg-F delta. The initial TTKXCOEF constant was set at 0.995, 5 deg F, or 1094.5 deg F at 1100F.

A GE Evendale (Ohio) report issued in 1977 noted that when Type K thermocouples were used in the 900F–1000F range their calibration shifted to indicate a higher temperature than actually existed. The phenomenon is metallurgical in nature. Conclusion: The thermocouple "ages" with temperature cycles, and the calibration shifts (Fig 1).

During the MS6001A "SPOTS" test in 1978, the exhaust thermocouples were indicating temperatures about 11 deg F higher than test-installed precision thermocouples. At that time, standard Type K t/cs (CrAl) were used with an expected accuracy of ±8.25 deg F at 1100F. The same difference between standard and precision thermocouples was confirmed by several field-tested units.

In 1984, work was started on the MS7001EA 7A4 generator—a cost-reduced and uprated 7A6 design. Word on the street was that the cost reduction had some problems with the structural properties of the end covers and bearing supports. The 7A6 generator was rated 81.5 MW. It was also rumored that the output of the 7A6 generator did not meet performance expectations. More rumors suggested that the generator losses were underestimated. Generator losses are on the order of 1 to 1.5 kW.



1. A thermocouple wire investigation revealed a calibration shift at different aging times versus temperature. Curves here represent aging times of from 2 to 16 hours for an aging temperature of 900F

In 1988, a "paper uprate" of from 81.5 to 83.3 MW (a 1.7% increase) was proposed for the 7001EA. The justification for the uprate was statistical data that indicated the average inlet pressure drop on field units was 2.5 in. H_2O instead of the 4.0 in. H_2O included in the performance guarantee at that time. A second justification was the introduction of the bias constant TTKXCOEF in Mark IV. However, no change to the value of the constant was recommended.

In 1993, a Performance Task Force (PTF) was formed to investigate the actual accuracy of thermocouples received. Result: A significant number of t/cs were found to approach the limits of accuracy (Fig 2).

A result of the PTF's findings was that the value of the constant TTKXCOEF was revised from 0.995 to 0.989. This corresponded to a calibration difference of 12.1 deg F. The conclusion was to use only precision Type K (CrAl) thermocouples with an expected accuracy of ±4.4 deg F at 1100F.

The performance shortfall rumored after introduction of the 7A6 generator seemed to have been resolved.

After 1995, all turbines shipped were outfitted with precision Type K thermocouples. The OEM issued Technical Information Letters (TILs) recommending the replacement of *standard* Type K t/cs with *precision* Type K instrumentation. Vendor quality was improved by assuring dimensional and material consistency of the wire material and heat treating after swaging. A set of 25 t/cs was tested at elevated temperatures to assess the results of improvements (Fig 3).

The out-of-limits reading for t/c 12 indicates a defective sample. The average error to the calibration temperature was 10.0 deg F. The expected error of precision t/cs is ±4 deg F. With the exception of No. 12, all thermocouples were within the expected accuracy.

Reports over time from the field indicated that some of the MS7001EAs had the TTKXCOEF constant set at a lower value than the 0.989 introduced in 1993. For every 10-deg-F increase in exhaust temperature control, an increase of 1.0% in output would result.

The TTKXCOEF constant in the Mark IV is behind a secondary password. To access this display, select "MENU 20 Enter." The CRT should go blank. Select MENU button "F5 Enter." Insert the secondary password "12673." The screen should display the TTKXCOEF constant and the system frequency selection.

In Mark V, the constant is listed in the CONST_Q.SRC file where it can be accessed by anyone.

Mark VI has three constants: TTKXCOEF, TTKXCOEF Part Load, and TTKXCOEF Base Load. All are accessible to the user.

Introduction of the constant apparently was discussed at a customer conference and resulted in several customers assuming that their units had some sort of performance shortfall. They saw the coefficient as a convenient way to increase output. However, as noted above, decreasing the constant results in overfiring and more rapid degradation of parts.

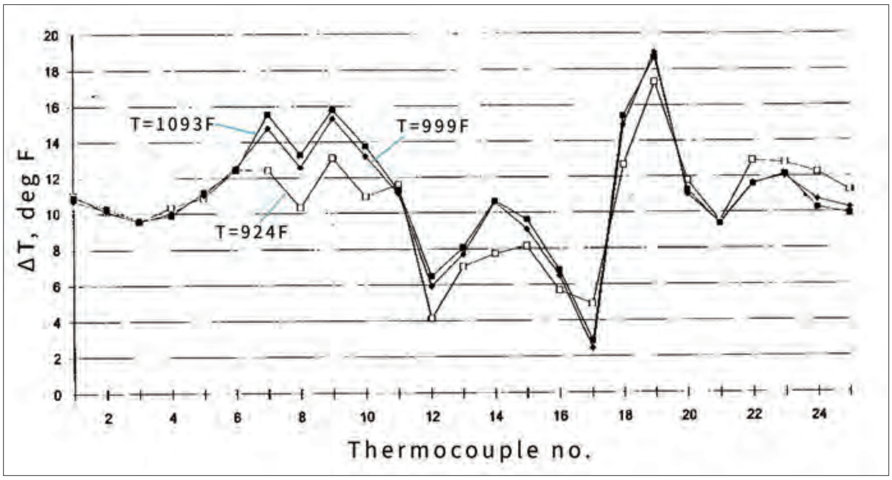
Using the constant to bias the exhaust temperature has drawbacks. First, it ignores the characteristics of the thermocouples actually installed. The 0.989 constant was based on a sample of 25 t/cs by averaging the actual-to-recorded temperature differences. The difference ranged from a low of 0.54 deg F to a high of 18.90 deg F.

What if all 18 t/cs installed on MS5001P, 5002B, 6001A and B, and 3002J tended to the low difference? The 12-deg-F exhaust bias would result in overfiring the unit by 22 deg F, or 20% of the peak rating. Note that 20% of peak rating results in a reduction in maintenance interval of 3200 hours.

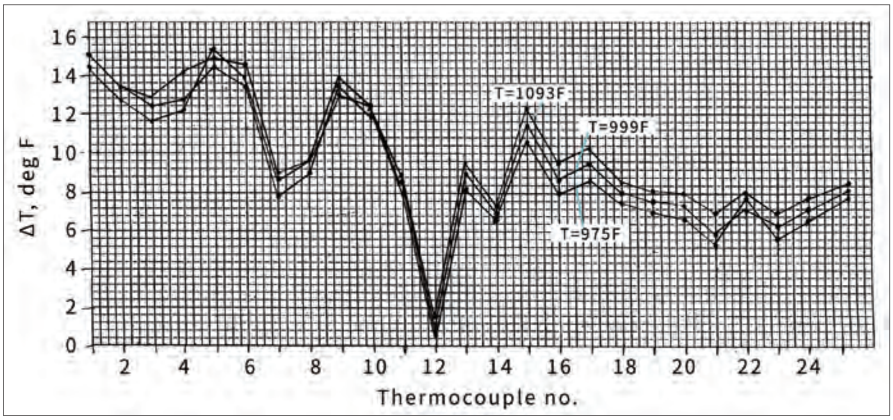
The question of thermocouple accuracy and benefit of correcting for that accuracy is debatable considering the basic thermocouple accuracy of ±4.4 deg F and the effect of overfiring by 7.3 deg F.

The thermocouple correction coefficient TTKXCOEF should be set to 1.0 for all units and applications.

Finally, the t/c correction coefficient TTKXCOEF could be used to correct a demonstrated thermocouple accuracy problem if all 18 t/cs were calibrated at base temperatures and demonstrated a consistent error. CCJ



2. Calibration data for Type K thermocouples. Investigation revealed that a significant number of t/cs approached the limits of accuracy. Average temperature was 10.88F



3. A set of 25 thermocouples was tested at elevated temperatures to assess the results of quality improvements made to the t/cs, as described in the text

LEGACY TURBINE FORUM, NO. 6 IN A SERIES

Damage report on a Mark I SCR static-exciter failure

An MS7001B gas turbine with Mark I Speedtronic™ controls and SCR static exciter-regulator experienced overcurrent damage to its exciter on a normal startup. Operators think the overexcitation event lasted for several minutes. However, an overexcitation alarm was not received and the unit was tripped when personnel smelled smoke. Staff opened the generator panel and found the instrument transformer, A1T, on fire. There were no other alarms or flags. Although the operators are not sure, they think the field voltage was over 120 Vdc and the current over 280 A when the unit was shut down.

Some of the rectifier-bridge diodes were damaged and replaced, as were some of the control diodes in the control-panel rack. Two rheostats showed distress, including A6P, which was replaced. There also was damage to the excitation J15 plug and wiring, which were completely replaced. Nameplate information: Regulator panel, 3579315A224A1; elementary, 44D209431. Instruction book is GEK-14772.

The point-to-point wiring, generator field components, online and offline resistors, 70R4 circuit, and the online control diodes and transformers were checked for shorts and grounds. The total resistance across the 70R4 was 1K and the resistance across the SCT (saturable current transformer) control winding and 90R5 was 25 ohms. No shorts or grounds, or open circuits, were found.

The unit was restarted, the field flashed at 40% of the turbine speed setpoint (TNH), and voltage built up slowly. At about 65% speed, field amps started rising rapidly; the unit was tripped at 260 A. Generator voltage was 11 kV and field voltage 108 Vdc. Investigators found the A1T instrument transformer damaged (photo). No other apparent damage was done to components or wiring.

Conclusion: Corrective action taken has not resolved the problem.

The A1T instrument transformer is across phases 2 and 3 of the PPT. Since the voltages on phase 2 and phase 3 normally are the same, the instrument transformer reduces the PPT voltage to a lower control voltage. No current flows since the phases are at the same potential. It appeared that the problem might have been a fault in the phase 2 and/or phase 3 PPT, SCT secondary, or linear reactor which causes a difference in the phase voltages and current.

The components of the excitation system—SCT, PPT, linear reactors, rectifier bridge, and field resistance—were tested and in operating condition. No faults were found. One resistor in the offline manual circuit, C6R, was found damaged and replaced.

The manual-to-automatic transfer relay, 83SR, was disabled to allow the manual regulator to check the offline and online voltages. The unit was started. At 40% TNH the field was flashed and the generator voltage started to increase. At full speed no load (FSNL), the generator voltage was 5 kV. The offline rheostat 90R5 was reduced to minimum resistance, but the voltage would not go below 15 kV.

Operators shut down the unit and adjusted the offline resistor C6R to increase resistance. Note that this is the resistor that had been replaced. Personnel started the unit and were able to adjust the FSNL offline voltage to 13.8 kV. Next steps were to close the breaker and adjust the online voltage to 13.0 kV.

Then the unit was shut down and the manual-to-automatic relay 83SR enabled. Restarted the unit, the field flashed, and the generator voltage increased. At 95% speed, control was shifted from manual to automatic. Generator voltage was about 12 kV and rising very slowly. At FSNL, offline rheostat 90R1 was adjusted, but had no effect. Also, 90R4 did not change the voltage.

The breaker was closed and negative-5 MVRS generated. The load was increased to see if the automatic regulator would control. VARS increased, but the generator voltage did not increase with load. The unit tripped at 20 MW with the field ground, generator differential, and loss-of-field protective relay flagged.

Operators meggered the field, finding high resistance. This would indicate that the generator differential and field-ground relay was a result of the trip—not the cause.

To eliminate the automatic regulator circuits, the 83SR relay was disabled and the unit restarted. The machine was ramped to base load—about 40 MW. Generator voltage remained at less than 13.8 kV and the VARS were 20.6. Conclusion: The manual regulator was working properly. The problem appeared to be with the automatic regulator.

The unit was shut down yet again and staff started checking the components of the auto-regulator panel. Finding: Resistor A7R in the A1CD gated diode circuit, 22,700 ohms, open circuit; replaced it.

Following the recommendation in the GEK troubleshooting guide for low armature voltage, personnel replaced the A1Z Zener diode, the A1CD gated diode, and the A2CD gated diode. Restarted the unit again with no improvement.

Next, replaced the saturable reactors A1SX and A2SX in the 90R4 input. Success! Upon unit restart, the automatic regulator was able to control generator voltage.

Conclusion: Test of the GAC devices—SCT, PPT, and linear reactors—indicated no faults. A reasonable root cause is that one or more of the connections on the SCT, PPT, and linear reactors introduced resistance which created a voltage and current differential between phases 2 and 3. Result was a significant overvoltage and overcurrent in the field wiring and control components. This problem was corrected when the com-

ponents were isolated for test and reconnected.

An increase in resistance for one linear reactor would cause a voltage drop across it, resulting in a decrease in field voltage in the SCR of that phase. The other two phases then would attempt to increase the field voltage, resulting in overvoltage and overcurrent.

The exciter PPT, SCT, linear reactors, and diodes normally are located in the unit GAC in an enclosed cabinet. In this particular installation, the devices were mounted in an enclosure which was not weatherproof. Over the years, protective screens, weather strips, doors, and walls had allowed weather to affect the devices in the enclosure.

Bear in mind that maintenance on the generator and exciter high-voltage terminations should be done during the 50,000-hr outage or every six years—including inspection and upgrade of terminations showing signs of the effects of ambient conditions.

Two incidents have been reported recently on MS6001B engines shipped in 1996:

First: The affected site experienced damage to the GAC enclosure, including the access doors being blown off. Fault was a phase-to-ground short on the GAC PPT caused by rainwater entering the GAC from rust damage to the roof during a particularly heavy thunderstorm.

Second: This incident involved a series of trips and alarms, including: generator differential, DCS trip, TCEA PTR relay trip, operator selected excitation off, loss-of-excitation transfer to manual regulator, and excessive volts per hertz.

At one point the EX2000 remained at A5 and would not reset. Investigators found a rusted panel in the GAC compartment that allowed water to enter the cabinet in the area of the excitation control system. Although the EX2000 was not wet, there was standing water on the floor nearby. The high humidity level affected system electronics. The leak was repaired and the GAC dried out. Then the EX2000 was initialized and came back online.

As in the case of the first GAC excitation failure, bear in mind that enclosure age requires additional consideration when there is deterioration to the integrity of the compartment.

End notes: GE introduced the SCR static exciter-regulator in 1969. The Potential Source Excitation System followed in 1983. It featured ac and dc regulator control and added overvoltage and overcurrent protection. Some applications used linear reactors, which may have been involved with the static exciter-regulator failure.

Because more than a thousand MS5001, MS6001, and MS7001 gas turbines were shipped from January 1969 to December 1982, when the SCR static exciter-regulator was a standard component, the possibility of a similar failure exists on these turbines.

Finally, the earlier recommendation for scheduled maintenance on exciter HV components should apply to units shipped from 1969 to 1983 and is a good idea for any gas-turbine installation. CCJ

A1T instrument transformer suffered damage shortly after unit restart

EHF2025 highlights industry's growing challenges with aging HRSGs and flexible operation

The eleventh annual European HRSG Forum (EHF2025), held May 13–15 in Prato, Italy, drew 95 participants from 20 countries, including 27 users. Co-chaired by Barry Dooley of Structural Integrity and Bob Anderson of Competitive Power Resources, EHF2025 continues its mission of advancing best practices and global knowledge-sharing in combined-cycle and HRSG operations. The event, organized by Mecca Concepts, is supported by IAPWS in association with ABHUG and the US and South America HRSG Forums.

EHF2025 offered 23 technical presentations, including a workshop on cycle chemistry, and featured strong international representation across plant operators, OEMs, engineers, consultants, and vendors. Seventeen sponsors supported the event: Precision Iceblast Corp, NEM, Dekomte, Freudenberg Flow Technologies, TÜV Rheinland, New Componit, Advanced Valve Solutions, Tuff Tube Transition, TesTex, Quest Integrity, Metroscope, OMB, Pruss, Fuel Tech, Arnold Group, IMI, and Thermic Systems.

Global priorities: aging fleets, flexible ops, and cycling fatigue

A consistent theme across presentations: reliable, flexible operation of aging HRSGs remains a top concern for users worldwide. Daily cycling, faster startups, and deeper turndowns are placing growing stress on pressure parts and internal components, especially in:

- Superheaters and reheaters (creep and fatigue failures)
- HP evaporators (FAC and under-deposit corrosion)

While pressure-part upgrades using modern materials are often proposed, many operators find these investments difficult to justify amid long-term plant uncertainty. The European Pressure Equipment Directive (PED) was also highlighted, especially in Germany, where HRSGs must meet stricter design and compliance requirements beyond ASME code.

Plant cycling has also impacted inline valves such as main steam stops. Inspections and design improvements are now essential for ensuring durability under cyclic conditions. Additionally, SCRs with enhanced performance are becoming mandatory in many new combined- and simple-cycle applications.

One notable development: ammonia vaporization without hot gas fans, offering potential cost and maintenance reductions in SCR systems.

Tube failures: prevention, inspection, and root cause clarity

HRSG tube failures (HTFs) continue to dominate reliability discussions. Key takeaways:

- Only 8% of plants globally have a formal HTF reduction program in place.
- Successful programs require top-down commitment and cross-functional involvement.
- New templates and benchmarking tools for tube failures, FAC, and cycle chemistry are available.

Root cause accuracy remains vital. Case studies emphasized the need for experienced metallurgists to avoid misdiagnosing the failure mechanism. The correct determination of fatigue, FAC, or UDC is critical to prevent repeat events.

Flow-accelerated corrosion (FAC) again topped the list of tube failure mechanisms. Presenters detailed:

- The role of pH control in two-phase FAC
- Importance of oxidizing power in preventing single-phase FAC
- The linkage between UDC and poor chemistry, often worsened by corrosion product transport

Case studies included robotic waterside inspections that now allow access to upper headers for thickness readings. Efforts are underway to enable robotic internal deposit density measurement for HP evaporators.

Innovative repair methods, such as tube sleeves, are gaining traction as cost-effective, short- to mid-term solutions to extend unit life.

Cycle chemistry: global benchmarking and new procedures

Dooley presented global chemistry benchmarking results and the latest IAPWS guidance. New data show:

- 86% of plants lack effective corrosion product monitoring
- 80% operate with substandard instrumentation
- 78% do not monitor drum carryover
- 73% do not question legacy chemistry practices

A new IAPWS decay map and corrosion product monitoring procedure now allow operators to evaluate the effectiveness of chemistry during operation and shutdown.

Updates on Film Forming Substances (FFS) noted:

- Documented reductions in corrosion product transport in water-touched circuits
- Limited or questionable protection in steam circuits
- Risk of under-deposit corrosion and "gunk" formation when pre-application steps are skipped

- Reports of increased HP evaporator fouling and deposit load when FFS are misapplied

Attendees also received updated IAPWS Technical Guidance Documents (TGDs) for combined-cycle plants.

Transients, valves, and layup risks

Thermal transients continue to drive operational issues. The latest data show:

- 85% of plants experience leaking spray water at attemperators
- 92% use valve logic that encourages leaks
- 37% report overspray, 30% allow manual control, and just 20% routinely inspect attemperators
- Only 38–40% effectively drain the HPSH/RH during startup

Valve-specific sessions covered high-temperature gate, globe, and check valves, relifing of main steam stops, bypass pressure control valve selection, and the benefits of combination stop/check valves.

Two HRSG layup failure scenarios were flagged for potential safety impact:

1. Leaking or open cold/hot reheat isolation valves on a non-operating HRSG during 2×1 operation can allow steam from the operating unit to backflow and flood the reheater. If undetected, this condition may lead to water hammer or even steam turbine water induction during restart. Installing an alarm to detect positive pressure in a non-operating reheater can provide critical early warning.
2. During hot layup, normal condensation in the high-pressure superheater (HPSH) can accumulate at the bottom of certain harps, forming a loop seal. This trapped water can migrate upward into hot headers and pipework, posing a risk during startup if not properly drained. A differential pressure alarm between the HPSH outlet and HP drum can help detect this condition and prevent damage.

Fireside cleaning and plant performance

Gas-side fouling remains a primary performance issue for HRSGs. Two cleaning technologies received attention:

- Ice blasting
- Pressure waves

For HRSGs with badly fouled finned tubes, cleaning remains one of the fastest ROI for the CCGT plant recovering generating capacity loss due to gas-side pressure drop. New developments in pressure wave cleaning were discussed, including improved performance when used while deposits are still hot, before moisture absorption increases adhesion.

A new short-flame-length, self-supporting duct burner design was presented as a retrofit option for older HRSGs and a design advancement for new builds.

Additional case studies and conference events

Other highlights from EHF2025 included:

- Side wall penetration seals for large-movement expansion
- Valve and inspection technology demonstrations
- Updates on pressure part failures and mitigation
- Advanced inspection access tools for evaporators and economizers

To close out the successful technical sessions, a conference dinner, hosted by Precision Ice Blast, was held at Conservatorio San Niccolò in the heart of Prato, offering delegates a scenic venue for informal exchange.

Looking ahead

The twelfth European HRSG Forum (EHF2026) will return to Prato, May 19–21, 2026. For information, contact Barry Dooley (bdooley@structint.com / bdooley@IAPWS.org) or Bob Anderson (anderson@competitivepower.us). Additional updates will be posted at www.europeanhrsgforum.com. CCJ

Leadership Academy highly beneficial

Developed by and conducted for employees of NAES Corp to ensure the company's ongoing success

Academy team leader: Alan Bull, VP, O&M services

Challenge. In evaluating its success in becoming the largest provider of third-party energy services, NAES Corp recognized that its success is based largely on the leadership demonstrated by its employees at all levels. To ensure the company's ongoing success, continue to provide best-in-class performance, and prepare for the natural course of growth and succession, NAES executives recognized the need for ongoing training of current leaders, as well as leadership development training for those aspiring to become leaders.

Solution. The company assembled a team of employees who were passionate about leadership to develop and establish the NAES Leadership Academy. With a mission of *"Growing leaders today to meet the challenges of tomorrow,"* the team began offering a leadership development program in April 2019 that has included the following components:

- Monthly webinars featuring internal and external speakers providing training on leadership topics—a program now in its sixth year.
- Online cohort classes with computer-based material and periodic group discussions for first-time leaders, experienced leaders, and those aspiring to be leaders.
- Cohort book-study classes where participants progress together through a leadership book over several weeks and have online discussions around questions and ideas.
- Recommendations for books and outside training courses. These are reviewed by the Academy leadership to ensure proper content and quality.
- Promoting additional articles and publications covering leadership development topics.

Results. Since its inception five years ago, the NAES Leadership Academy has provided hundreds of hours of leadership training, resulting in improved skills for employees at every level of the company and helping to prepare aspiring leaders for advancement and success. This training has included the following:

- More than 60 monthly webinars, each attended by between 150 and 350 employees from the NAES plant fleet, corporate team, and subsidiary companies. Every webinar is then published on the NAES website for future reference.
- Dozens of third-party leadership development classes, each targeting specific leadership skills. These classes have been attended by more than 100 employees.
- Eleven cohort classes, each attended by 15 to 25 employees, discussing leadership books focused on leadership essentials, first-time manager training, and experienced-leader training.
- Support for HR, upon request, with recommendations of targeted classes and materials to address the department's specific training needs.
- Providing keynote speakers for NAES conferences who focus on leadership skills development.

In addition, the feedback from senior leadership and employees has been overwhelmingly positive and has resulted in stronger cultures and improved retention within NAES' corporate team and its plant sites.

According to Charlie Hoock, NAES' president of energy services, "The Leadership Academy is an important way in which NAES invests and develops its employees, thereby enhancing the level of service we can provide to our clients. By developing our leaders, we are enabling our future as well as the future of our people."

Employee testimonials included these:

- "I thought today's Leadership Academy session was one of the best and most practical with great ideas easily applied. It might be interesting to invite this speaker back for another talk; I thought he was phenomenal."
- "Thank you for this webinar. It has been a topic that I have struggled with for some time."
- "I thoroughly enjoyed the webinar. I put the act of expressing gratitude into action almost immediately. It has been very well received and seems to be contagious. The focus on the positive has definitely left me feeling very optimistic."
- "I wanted to share how grateful I am to have participated in the webinar on burnout. I truly enjoyed it and learned from it. Thank you for offering this opportunity. I look forward to attending future webinars."
- "I have been participating in the presentations for years now and have sincerely enjoyed them, but today's session was EXCELLENT!"
- "I did things a bit differently today; typically, we watch the presentations 'alone' in our respective offices, but today I put it up on the big screen and we watched together. I'm glad that I did. The presentation was on-point, and we were able to discuss and share as our own small team. We moved a little closer on our path toward perfection today."
- "Thank you for bringing these and other presentations to the team as we continue to grow in our leadership roles."
- "I enjoyed the team meeting calls after each lesson. Since I'm relatively new to a leadership role, it was extremely helpful for me to listen to the thought process and ideas of others on how to handle different situations."
- "Not only did I find the First Time Manager cohort informative and relevant to the experiences I was encountering as a first-time manager, but it also was quite enjoyable. The content of each week's tracks, combined with the shared insights from the other members of the group, was educational and entertaining. The facilitators were excellent. I highly recommend this cohort to others as they begin their management journey."
- "The First Time Manager's course was very engaging, and the timeline and the content fit well with my workload. I found that the most rewarding aspects of the course were the discussions that occurred among all of the other first-time manager attendees; it was great to listen to my peers and hear perspectives that I wouldn't normally have access to."
- "I really enjoyed the First Time Leadership journey. It provided tools and ideas that I was able to immediately use with my team. I have been telling just about everyone just how good, fun, and beneficial this was. Thank you so much for doing this."
- "I thought this was a very good course and thankful NAES provided it. The facilitators did a great job coordinating the training. I hope NAES continues this effort."

Project participants:

Alan Bull, VP, O&M services, Leadership Academy team lead
Eric Woods, operations director
Vanessa Castillon, HR business partner
Sean Thompson, supervisor, NERC services
Jeremy Sylvain, maintenance supervisor, ENMAX Cavalier Facility
Jason Hixson, plant manager, Victoria Power

River Road Generating Plant

Owned by Clark Public Utilities
Operated by GE Vernova O&M

248 MW, gas-fired 1 × 1 7F.02-powered combined cycle (STAG configuration) equipped with a Foster Wheeler HRSG, GE A12 steam turbine, and GE 324 generator, located in Vancouver, Wash

Plant manager: Robert Mash

Safer handling of chemical totes

Challenge. Gravity feeding the contents of a chemical tote into a stationary tank by strapping the tote to a forklift and tilting the forks to flow chemical directly from the tote into the stationary tank presented a safety risk to personnel.

Solution. Purchased a portable chemical containment vessel (Fig 1) and placed it next to the concrete containment where the stationary chemical tank is located. The portable containment is a secondary vessel that allows access for a forklift to stage and remove the totes.

Next, a flexible hose was installed, as shown in the photo, so a pump placed in the tote could transfer the chemical from the tote to the stationary chemical tank. A shut-off valve on the flex hose enables draining the hose into the tank when the transfer is completed.

Results. River Road personnel installed all components required to implement their proposed solution and conducted a test to demonstrate its viability by offloading the chemical from the tote to the stationary chemical tank. The entire process was completed within 20 minutes without incident—including moving the chemical tote from the storage area to the portable containment—proving the new process is safer, and easier for team members to handle.

Project participants:
Justin Hartsoch, operations manager
Jake Sanderson, operator
Marjorie Brice, EHS specialist

1. Plant personnel demonstrated a safer method for transferring chemicals from totes to a stationary tank

Plant's value, calculated daily, determines operating conditions

Challenge. Maintaining reliability is the most critical aspect of plant operations at River Road. As a public utility, plant output is dedicated to its customers. If the facility goes down, the owner must procure replacement energy which is subject to volatile market prices.

Over the past few years, the energy market has been much more volatile than it had been historically. Fluctuations in fuel and power prices can change dramatically in a day, possibly less. Last winter there were days that would have cost the utility upwards of $1.6 million in replacement energy had the plant tripped.

Sometimes the information that flowed from the power analyst to the plant was not passed on until the day that was impacted. This presented problems when contractors were scheduled to be onsite for repairs and also interfered with work planned by the O&M team.

The plant and the power manager needed a way to communicate the daily value of the plant to staff in a timely manner. Ultimately, the goal evolved into creating an "operational color code." This code would then be linked to maintenance tasks based on the *plant trip risk* inherent with each of the tasks.

Solution. Clark Public Utilities collaborated with River Road's O&M team to develop a process to communicate the daily value of the plant to the operations team. The power manager created a spreadsheet that calculates the daily value of the plant. The calculations use the value of selling already-purchased gas and buying replacement energy at market prices.

The utility's internal risk group established these three levels of value and assigned each a color:

- Low-value day, GREEN.
- Intermediate-value day, ORANGE.
- High-value day, RED.

Results of the daily-value calculations are delivered to the operations team daily for the following day, or days (Fig 2).

With the color code in place, the O&M team worked collaboratively with craft, operations, and managers to assign maintenance risk values to typical work categories. The goal was to complete only high-risk maintenance during GREEN days and to limit high-risk maintenance on ORANGE days. Maintenance on RED days was limited to low-risk activities (Sidebar).

Results. Day-ahead collaboration and communication has allowed scheduling and execution of work based on plant value. The operational color codes eliminate ambiguity regarding work that can be done; plus, it has improved communication between the plant and the utility's analysts.

The operational code is reviewed during the morning meeting to determine whether scheduled work can be performed or should be postponed.

The information communicated also is included in the daily operating plan. The operations team has a better understanding of the importance and value of the plant and how their daily work can impact utility reliability. It also demonstrates the communication and collaboration between the owner and O&M team.

Project participants:
Robert Mash, plant manager
Terry Toland, energy resources manager


DAILY OPERATING PLAN &
OPERATIONAL ORDERS

Weekend Ending 1-14-24

Operation Status
Code Red
Consecutive days without a Lost Time Injury
4728

EHS ACTIVITIES

Injuries:
Risk Assessments / Permit Review:
Stop Work / Environmental Issues / Near Miss:

NEW INFORMATION

2. Daily plan communicates the current value of the plant to the operations team

What the operational color codes mean

RED examples.
- Calibration or tasks associated with air-permit maintenance/ linearity testing.
- NPDES equipment testing and calibration.
- Steam-turbine stop- and control-valve testing.
- Diesel/generator testing.

ORANGE examples.
- Code RED tasks.
- Swap-out of equipment.
- Motor and pump operational testing.
- Change-out of motor air filters.

GREEN examples.
- All Code RED and ORANGE tasks.
- Routine plant maintenance.

3. Deposition of calcium silicate inside the media dramatically degraded cooling-tower performance

4. Garden screens for reducing the penetration of sunlight into the cooling tower were not conducive to long life

5. Media was replaced throughout the five-cell cooling tower

Cooling-tower performance upgrades

Challenge.

1. Cooling-tower efficiency had slowly decreased since the last fill replacement in 2009 because of the deposition of calcium silicate inside the media prior to installation of Flow Tech devices to mitigate the issue (Fig 3). Heat rate increased because warmer water was flowing through the condenser tubes. Warmer water also compromised the ability of the heat-rejection system to cool the generator and lube oil in summer.
2. The garden screens for reducing sunlight inside the cooling tower were not sufficiently robust to handle local weather conditions for more than about a year (Fig 4). A best practice was to take down the screens before winter when accumulations of ice and snow could damage them. However, the screens often were subject to tearing when they were reinstalled in spring.

Staff wanted to continue shading the tower to reduce algae growth, thereby reducing the consumption of water-treatment chemicals and their impact on the environment. A robust, permanent solution to the algae solution was the goal.

Solution.

1. Replaced the media throughout the five-cell cooling tower (Fig 5).
2. Installed ridged sunscreen media on all sides of the cooling tower to block the sunlight required for algae growth.

Results.

1. Reduced heat rate by about 200 Btu/kWh; increased gross capacity factor by about 1%.
2. Reduced the consumption of chemicals used for bio-growth control by 40%, saving $10k annually. Eliminated the need to purchase new garden screens annually, saving another $5k. Reduced labor hours by eliminating annual replacement of sun screens, saving $2.5k. Eliminated rental costs for the lift required for replacing screens, saving another $2.5k

Project participants:

Terry Toland, energy resources manager
Ken Roach, maintenance manager
Justin Hartsoch, operations manager
Steve Ellsworth, shift supervisor

Improved instrumentation identification tags

Challenge. Over time, and with turnover of personnel at River Road Generating Plant (RRGP), instrumentation tags plant-wide came to have various non-standard variations of tagging and markings. It became confusing for plant personnel to correctly identify instruments and the processes being controlled.

It also created a conflict of understanding between control-room and outside operators when referring to field instruments. CROs know the instruments by description of what they control; outside operators usually see an instrument tag number without a description.

RRGP has instrument racks where three to 12 instruments can be mounted together in a central location. Thus, it can be time-consuming to identify a specific instrument without proper tags, or a mix of tag types.

To illustrate: There may be one tag with the instrument number on the device and a faded/smeared calibration sticker, and permanent pen markings on the outside or inside of the device lids. Inconsistent markings have included multiple ranges for the devices, as well as other changes that have been made over the years (Fig 6).

The O&M team needed a way to standardize the instrument details for all plant personnel to assure proper identification of instrumentation quickly and efficiently, particularly during emergencies or other critical times.

Solution. The I&C team created a weatherproof instrument tag that provides the following information:

- Instrument tag number (matches nomenclature on the P&ID).
- Description of device. Identifies the process the device is measuring and serves as a secondary form of verification with the CRO—such as *HP drum level "A" transmitter.*
- Control-system range as displayed in the control room.

6. Multiple versions of RRGP instrument tags were converted to a standard format, enabling quick and concise bidirectional communication between the field and control room

7. Pertinent information for a given instrument is displayed on its unique identification tag

8. The new ID tags facilitate communications

- Calibration range of the device.
- Output range of the device.
- Termination. Location of wires landed—input or output—on the control system.
- Criticality. Specifies if the device is critical to operate the plant safely and efficiently.
- Alarm/trip points. They can be useful when comparing to a local gauge for outside-operator rounds.
- Notes. Any additional information that would be helpful to personnel in the field.

The foregoing information is placed on a 3 × 6 in. tag to provide all information needed for quick and concise bidirectional communication between the field operator and the control room or technician (Fig 7).

Results. The new tags reduce the risk of misidentification of instrumentation. Personnel confidence improved after their installation (Fig 8). Plus, staff knowledge increased with regard to field instrumentation. And communications regarding reference to instrumentation has improved during troubleshooting and normal operations.

Work-order details now are more complete, allowing personnel to correct issues often in less time than previously.

Others have been impressed with the RRGP tags and have adapted them to suit their facilities.

Project participants:
Steve Dahl, IC&E technician
Jack Blair, IC&E technician

Dealing with an outage parking challenge safety in mind

Challenge. Depending on the amount of work being performed during an outage, the space for plant personnel and contractor parking becomes a challenge. Some sites do not have the real estate to support the capacity necessary for component laydown areas, contractor trailers, and personal vehicles. Safety is a priority and insufficient parking creates several hazards.

River Road personnel identified an unused lot on the property adjacent to the plant. It had been used during construction but had remained vacant for many years. The lot was overgrown with vegetation and weeds. The ground was soft as well.

Solution. Staff developed a plan to prepare the lot for safe parking. Overgrown vegetation, weeds, berry vines, and small trees were removed. The soft gravel surface was compacted, and new gravel was added and compacted for stability (Fig 9). Portable lighting, temporary parking barriers, and ingress/egress stairs were added to allow access to the higher-elevation parking area. The space was now safe for personnel, visitor, and contractor parking.

Results. The vacant lot was successfully used as a safe parking space for the duration of the month-long outage. The location of the parking area outside the plant eliminated unnecessary vehicles from entering the plant roadway. This dramatically reduced traffic inside the plant making it safer for all personnel walking on the roadway (Fig 10).

It also provided ample room for large equipment and component staging in close proximity to work locations. Delivery of tooling and specialized equipment was made safer and more efficient with no traffic on the plant roadway.

The new lot is now the plant's standard parking area for RRGP personnel, visitors, and contractors during outages.

Project participants:
Margie Brice, EHS supervisor
Mike Buhman, mechanic
Steve Ellsworth, shift supervisor

9. Unused lot next to the plant was converted to a parking area. One of the first steps was to compact its soft gravel surface

10. Ingress/egress stairs were added to access the higher-elevation parking area

Empire Generating LLC

Owned by Empire Acquisitions LLC
Operated by NAES Corp

635 MW, gas-fired 2 × 1 7F.03-powered combined cycle with Alstom HRSGs and a GE D11 steam turbine, located in Rensselaer, NY

Plant manager: Chet Szymanski

Cooling-tower mod improves maintenance access

Challenge. Empire Generating's cooling tower is designed with a dry section that contains heat exchangers to assist in plume abatement. Because of their location, age, and duty cycle these heat exchangers routinely develop leaks that require tubes to be plugged and pipes repaired.

Work on the external side of the heat exchangers (on the outside of the cooling tower) was never an issue, as there are work platforms. However, work on internal side (inside the cooling tower) proved more problematic given the lack of work platforms and the need for fall protection and to work at odd angles off tower structural-support members or scaffolding.

Solution. At the suggestion of plant personnel, the installation of an internal walkway was investigated. As envisioned, it would run the entire internal length of the cooling tower, like the existing external walkways. But to accomplish this it would be necessary to modify the internal structure of the tower, cutting "doors" between the sections, thereby reducing each section's effectiveness.

This was not viewed as an acceptable solution. Instead, the design was modified such that internal cooling-cell integrity would be maintained and the walkway would only provide access to two cells from one ladder entry point (similar to access before the walkway was installed).

Results. The walkway was installed by Cooling Tower Depot during Empire's 2023 fall outage (Fig 1). With improved access, Empire employees can work more comfortably on the internal side of the heat exchangers, without worrying about falling or being at odd angles and trying to hang onto slippery support cross members.

Project participant:
Dwayne Boyer, O&M manager

Beware local isolations on chemical pumps

Challenge. Empire has several types of chemical-pump skids that vary in pump type, size, and power requirements. Additionally, some skids are powered by multiple sources from their local power distribution panel (PDC).

As some of the older pumps hit their lifespans and required replacement/repair, staff recognized an issue that also was an opportunity. When performing LOTO on a single failed pump on the phosphate-feed-pump skid, which has four 120-V single-phase and two 480-V 3-phase power sources, techs found that each of the individual pumps fed from the PDC could be isolated only by pulling fuses after hanging a LOTO on the *entire* PDC. This meant taking all the associated pumps out of service.

Thus, to work on a single chemical pump without interrupting normal plant operations, multiple LOTOs had to be hung for an IC&E tech to open the associated PDC and remove and reinstall the applicable fuses.

Solution. After some deliberation at a management-of-change meeting, staff determined a better solution for servicing the phosphate feed pumps. Rather than having to use multiple LOTOs to remove and reinstall fuses, Empire management approved installation of individual, lockable, door-mounted disconnects for each pump within the PDC (Fig 2). This would eliminate the need for an IC&E tech to open the panel and pull fuses and shut down power to the whole system.

The individual disconnects would enable any qualified Empire employee to LOTO individual pumps on the skid, which also would simplify the LOTO process while the phosphate system is in use.

Results. The design upgrades worked as planned and the modifications ensure a safer, more efficient LOTO and repair process. Given this success, the same upgrades are planned for other chemical-feed-pump PDCs during upcoming outages.

Project participants:
Chester Szymanski, plant manager
Dwayne Boyer, O&M manager
Patrick Riley, operations supervisor
Rob O'Connell, EH&S manager
Ben Graham, IC&E technician
Empire plant safety committee

1. Walkway provided safer access to cooling-tower heat exchangers for plume control


SAVE THE DATE
7F Users Group®
Annual Conference
May 18-23, 2026
The Woodlands Waterway Marriott
Hotel & Convention Center
Houston, TX

Multiple-skills training pays dividends

Challenge. Energy facilities have multiple departments, each requiring qualifications to meet their own specific responsibilities. Empire's org chart shows two departments: operations and maintenance, each with its own sub-departments. Both departments are crucial to plant functionality: Operations focuses on the operation of the plant, while maintenance performs preventive or corrective maintenance on all plant systems.

Over time, and with each staff focusing solely on its own specific roles and functions, a knowledge gap between the departments became apparent. Having each department perform its specific tasks only could create a scenario in which Empire might be in real trouble should one of the departments find itself short-handed for an extended period.

Solution. To safeguard the plant and its employees, a cross-qualification qualification program was designed and implemented, whereby specific employees from each department would be selected to train and qualify in the other. By expanding the knowledge and skillsets of these individuals, Empire would provide suitable backup support across a variety of tasks.

The first cross-qualification group involved two maintenance department employees (the water treatment technician and an IC&E tech) qualifying to become O&M techs. They were required, over a period of several months, to complete the full qualification process of an O&M tech and become approved by the plant manager to stand a shift. This provided these employees with key insights into the knowledge and daily tasks of an O&M tech.

The second step in the cross-qualification process involved sending an O&M tech to instrument calibration training alongside an IC&E Tech. The O&M tech who volunteered had prior electrical knowledge and expressed an interest in learning more about the IC&E tech's duties. This additional training gave him an understanding of how instrumentation devices work and how to calibrate them.

Results. With implementation of the cross-qualification program, Empire is creating a well-rounded workforce—each department having the knowledge and skills to fill roles and conduct different collateral duties. With the two additional qualified O&M techs, management is able to increase the support in the operations department during outage work. Also, it is able to have extra coverage that allows other O&M techs to pursue their cross-training.

Plus, having an O&M tech qualified for

2. Original non-lockable, hand-off-auto switches at left, lockable disconnects alongside hand-off-auto switches at right

IC&E tech duties provides additional support to that department during outages, and any other time the IC&E department finds itself short staffed.

As part of Empire's drive for continuous improvement, and taking advantage of employees' desires to learn, plant management supports the cross-qualification program to further enhance staff capabilities. Management plans to send another operations-department employee with prior electrical knowledge for instrumentation training. Additionally, based on the program's initial success, the O&M tech qualification requirement has been implemented for all new maintenance-department hires.

Project participants:

Patrick Riley, operations supervisor
Jason Glassbrenner, water treatment technician and safety committee chair
Ben Graham, IC&E technician
Devin Spain, O&M technician

Man-down-qualified personnel make for a safer workplace

Challenge. Attrition has created a large disparity in both age and operational knowledge between our O&M leads (a/k/a control-room operators) and technicians. As a facility staffed 24/7/365, there was a concern about what an O&M tech would do should he or she encountered a situation where the CRO became incapacitated.

Solution. Management discussed ways to address this challenge, developing a solution it named the "man-down qualification." It is designed to give the O&M tech some critical knowledge of what the CRO does in the control room and trains the technician to perform basic, yet vital, operations to keep the plant in a safe and stable condition until more-qualified help arrives. All individuals currently having O&M tech responsibilities, as well as those in the initial stages of O&M technician training, were required to complete the new qualification.

Some of the concepts within the new qualification standard include the following:

- Familiarization with navigation of both the ABB (balance-of-plant) and Mark VI (turbine) HMIs.
- Familiarization with Title V air-permit limits.
- Ability to change turbine modes of operation.
- Read/acknowledge system alarms.
- How to properly enter events in the logbook.
- Demonstrate proper three-part communication with the transmission operator (TO).
- Familiarization with emergency response procedures and the ability to implement them.

Upon completion of the man-down qualification program, an O&M tech has the ability to respond to any emergency—medical or otherwise—that the CRO may have. The tech is able to notify the TO and run the unit as directed, call Empire management and inform them of the incident, and properly log all information as required by governing authorities.

Results. Shortly after this process was implemented, staff witnessed first-hand its value: On a weekend night shift a senior CRO went down because of a known medical condition and was in and out of consciousness. Using his new training, the O&M tech called the TO, held plant load, called 911 and Empire management regarding the medical emergency, provided medical assistance to the downed CRO, and maintained a time log of the events as they occurred.

This event confirmed that man-down qualification should be an essential part of being a well-rounded O&M technician. It will continue to be a part of every new Empire O&M tech's qualification process for the foreseeable future.

Project participants:

Patrick Riley, operations supervisor
All qualified O&M leads and technicians

Faribault

Faribault Energy Park

Owned by Minnesota Municipal Power Agency (MMPA)
Operated by NAES Corp

265 MW, 1 × 1 7F.03-powered combined cycle equipped with a GE A10 steam turbine and CMI HRSGs, located in Faribault, Minn

Plant manager: Shawn Flake

Protective-relay trip logs reduce errors

Challenge. Accurate and complete gathering of data during abnormal plant operations can be difficult and lead to ill-advised decisions by management and engineers.

One of the most extreme events that can occur in an electric generating station is the dreaded "black plant" event, which can result from a protective-relay tripping scheme opening the main feed breaker at the plant interconnection to a substation. The electrical fault can be either internal or external to the plant.

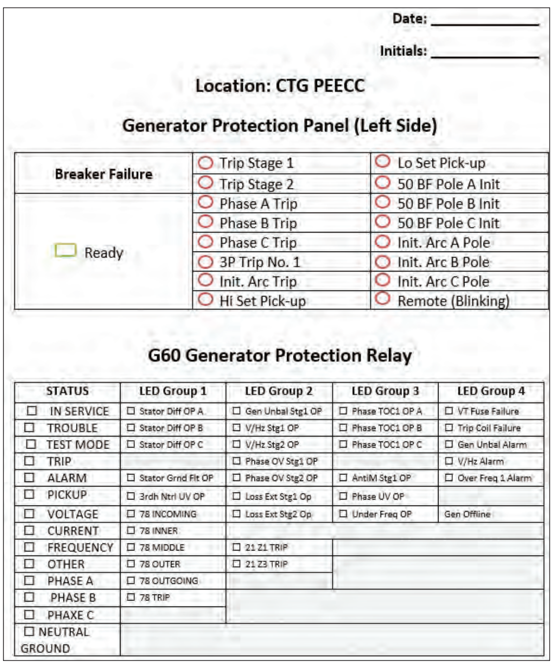
Plant managers, O&M techs, and/or engineers have the challenging task of trying to understand what caused the event. Reacting expediently often can mitigate further operational casualties by returning ac power to necessary equipment—including safety systems. Coincidentally, the desire to react quickly has the potential to lead to either acquiring partial or inaccurate information from protective relays.

Solution. Faribault Energy Park implemented protective-relay trip logs to identify the state of all relay outputs and flags accurately and quickly (Figs 1 and 2).

Physical copies of the trip logs hang on clipboards at each relay station in the plant. The logs are configured identical to the physical location, lights, and flags on the protective relays. This allows O&M techs to quickly transpose all information from the relay station to a paper document that can be used to troubleshoot electrical faults.

Results. Quick and accurate relay trip information has minimized impacts to plant equipment during electrical-fault events. During each fault event, O&M techs were able to accurately provide fault information to management. The data sets allowed managers to make quick, sound, and effective decisions—including switching orders and initiation of electrical restoration procedures.

Project participants:
Shawn Flake, plant manager
Scott Lowe, operations manager
Tim Mallinger, lead operator



Date: ____________

Initials: ____________

Location: CTG PEECC

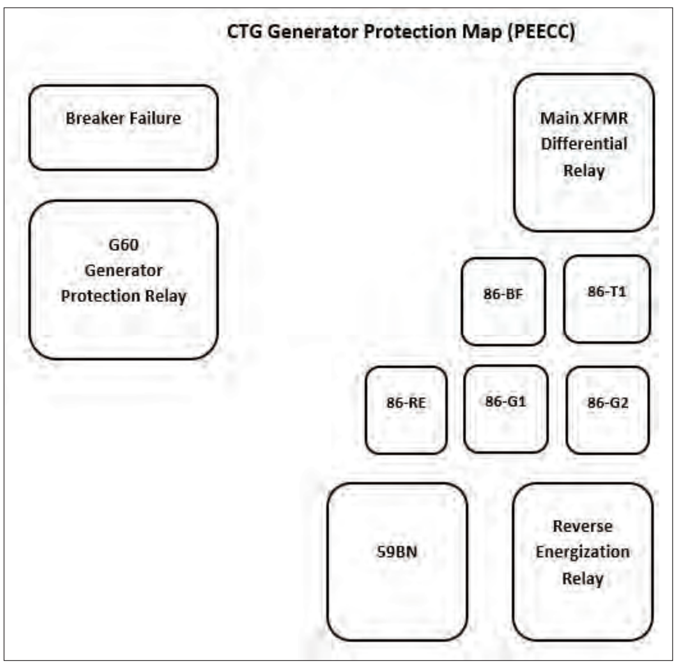
Generator Protection Panel (Left Side)

Breaker Failure	○ Trip Stage 1	○ Lo Set Pick-up
	○ Trip Stage 2	○ 50 BF Pole A Init
Ready	○ Phase A Trip	○ 50 BF Pole B Init
	○ Phase B Trip	○ 50 BF Pole C Init
	○ Phase C Trip	○ Init. Arc A Pole
	○ 3P Trip No. 1	○ Init. Arc B Pole
	○ Init. Arc Trip	○ Init. Arc C Pole
	○ Hi Set Pick-up	○ Remote (Blinking)

G60 Generator Protection Relay

STATUS	LED Group 1	LED Group 2	LED Group 3	LED Group 4
☐ IN SERVICE	☐ Stator Diff OP A	☐ Gen Unbal Stg1 OP	☐ Phase TOC1 OP A	☐ VT Fuse Failure
☐ TROUBLE	☐ Stator Diff OP B	☐ V/Hz Stg1 OP	☐ Phase TOC1 OP B	☐ Trip Coil Failure
☐ TEST MODE	☐ Stator Diff OP C	☐ V/Hz Stg2 OP	☐ Phase TOC1 OP C	☐ Gen Unbal Alarm
☐ TRIP		☐ Phase OV Stg1 OP		☐ V/Hz Alarm
☐ ALARM	☐ Stator Grnd Flt OP	☐ Phase OV Stg2 OP	☐ AntiM Stg1 OP	☐ Over Freq 1 Alarm
☐ PICKUP	☐ 3rdh Ntrl UV OP	☐ Loss Ext Stg1 Op	☐ Phase UV OP	
☐ VOLTAGE	☐ 78 INCOMING	☐ Loss Ext Stg2 Op	☐ Under Freq OP	Gen Offline
☐ CURRENT	☐ 78 INNER			
☐ FREQUENCY	☐ 78 MIDDLE	☐ 21 Z1 TRIP		
☐ OTHER	☐ 78 OUTER	☐ 21 Z3 TRIP		
☐ PHASE A	☐ 78 OUTGOING			
☐ PHASE B	☐ 78 TRIP			
☐ PHAXE C				
☐ NEUTRAL GROUND				

1. Protective-relay trip log is an example of what you might do



2. Generator protection map for a gas turbine

Hunterstown Generating Station

Owned by LS Power
Asset management by Competitive Power Ventures
Operated by NAES Corp

810 MW, 3 × 1 7F.04-powered combined cycle equipped with a GE D11 steam turbine, located in Gettysburg, Pa

Plant manager: Mark Kadon

Closing gaps in O&M knowledge through enhanced workforce development

Challenge. Anticipating industry-wide knowledge-gap challenges resulting from retirements and staff turnover, Hunterstown Generating Station saw the need to move early and proactively to ensure the continued excellence of its workforce.

Solution. In January 2023, Hunterstown began a series of ongoing process reviews and training programs. Management's first action was to overhaul the plant's operator qualification process, incorporating rigorous board reviews to ensure personnel have the requisite experience to fulfill their duties effectively.

Vendor partnerships were developed to upgrade staff capabilities. These included the following:

- Technical Training Professionals (TTP) was engaged in May 2023 to equip the plant's most recent hires with foundational skills essential for plant operation. This comprehensive training program—covering topics such as heat transfer, fluid dynamics, and electricity—provides a robust foundation for understanding plant operations. Additionally, a detailed exploration of Hunterstown's core equipment—including gas and steam turbines, ACC, and balance of plant—was initiated.
- Phil D'Angelo, an independent consultant, was brought in to provide specialized instruction on chemical processes relevant to plant operations.
- Foxguard Solutions was hired to bring personnel up to speed on critical cybersecurity topics and activities.
- ISPI Consultants Inc was hired to reinforce Hunterstown's commitment to safety and compliance by implementing onsite its Qualified Electrical Worker program with individual job-performance measures. This training course stresses both adherence to 70e electrical safety requirements and improving staff proficiency in establishing safe electrical working conditions.
- GE Mark VIe operator training was implemented in April 2024, enabling staff to acquire the necessary CRO skills, including logic interpretation.
- EtaPRO was engaged to provide management the necessary tools to safeguard the plant's ability to optimize performance. Program included advanced performance analysis and combined-cycle troubleshooting.

Results. The actions noted already have paid dividends by educating and empowering the plant's young workforce and by significantly overcoming concerns about any potential knowledge gaps. In turn, this has served to reinforce management's ongoing commitment to workforce development. Plans already underway include training on Emerson Ovation and an advanced program on Mark VIe controls, further solidifying staff capabilities to meet the industry's dynamic demands.

Project participants:
Mark Kadon, plant manager
John Marino, operations manager

Jackson Generation

Owned by J-Power USA
Operated by NAES Corp

1200 MW, two 1 × 1 combined cycles powered by Mitsubishi 501 JAC gas turbines and SRT40AX steam turbines with HRSGs from John Cockerill, located in Elwood, Ill

Plant manager: Scott Freese

Removing varnish and mitigating its formation

Challenge. Varnish in hydraulic systems can be triggered by a thermal event that causes the oil to start degrading. Since going commercial in May 2022, Jackson Generation has tested its control oil monthly. The control-oil skid serving the plant's steam turbine consists of two 100% oil pumps arranged in a lead/lag configuration that sit atop a 344-gal reservoir.

The system features both discharge and return filtration—including polishing filters and three fuller's earth filters. It protects inlet-guide-vane (IGV) and variable-guide-vane (VGV) actuators, as well as HP, IP, and LP turbine stop/control valve actuators. The trip-oil system also is supplied from the control-oil skid.

Each oil test conducted covered all the basic fluid health targets: particulates, acid, and water. The first oil analysis, in May 2022, revealed an acid number of 0.2 mg KOH/g with no water indication for Unit 1 and 0.16 mg KOH/g for Unit 2, also with no water indication.

The following month, on June 27, while attempting to start Unit 2, the startup permissive was lost because of IGV servo module deviation. This alarm is caused by the demand and the feedback of the IGVs being greater than 3%. A warranty claim was submitted and the IGVs were recalibrated.

Unit 2 tripped on July 30 because of an IGV deviation alarm. The servos for the IGVs were replaced with new ones from inventory. The old servos were sent to the OEM for inspection; signs of varnish were noted.

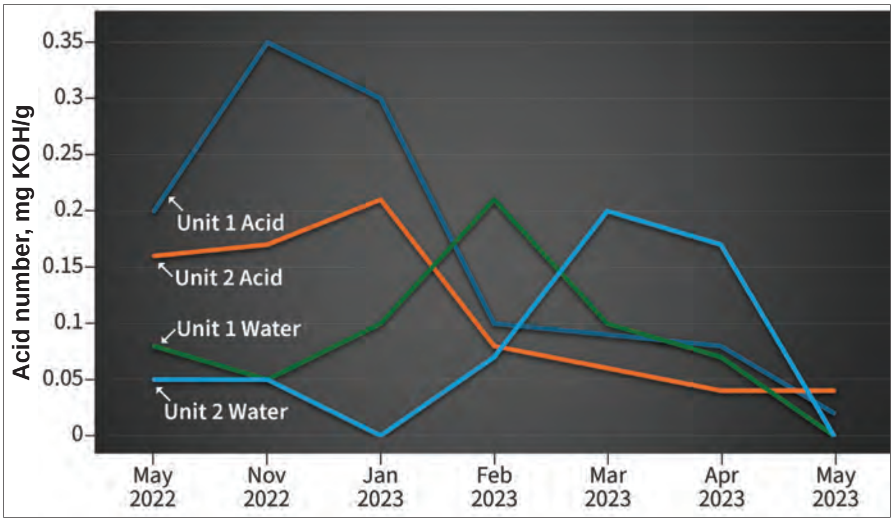
By November 2022, Unit 1 acid numbers had jumped from 0.2 to 0.35 mg KOH/g, Unit 2 acid numbers from 0.16 to 0.2 mg KOH/g.

Control-oil water content also had increased on both units, from no water indication on either unit to 0.1 on Unit 1 and 0.05 on Unit 2.

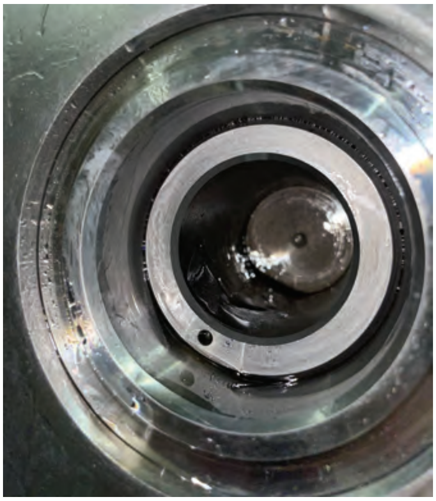
Varnish was affecting the IGV servos, as well as those for the turbine stop/control valves. On Jan 13, 2023 the Unit 1 turbine IP control valve started closing while at baseload because of a failed servo, which was replaced. Inspection of the failed servo revealed varnish damage.

Thus, the varnish problem affected every aspect of the control-oil system: Unit 1 had experienced five IGV servo failures, two VGV servo failures, and five steam-valve servo failures. Unit 2 had two IGV servo failures, one VGV servo failure, and four steam-valve servo failures.

Solution. Collaboration among the entire Jackson Generation team, JPower engineers, and Mitsubishi resulted in a plan determined to correct the varnish problems on both units. In January, a rental side-stream varnish filtration skid was installed on Unit 1 along with ion-exchange filters. After running the filter skid for a month, the site team inspected the fuller's-earth filers on the main control skid, finding they never were



1. Acid and water test data are for Jackson Generation's first year of operation



2. Trip-oil poppet valve for IP control-valve actuator is stuck open installed during commissioning.

Fuller's earth filters were installed along with a water removal cart, water being a byproduct of skid operation. Acid and water indicators soon began dropping on Unit 1, providing confidence to move the cart to Unit 2 (Fig 1).

During the spring 2023 outage, both control-oil reservoirs were drained to 50% and replenished with new oil. The result of this had an initial negative effect. Varnish numbers went up causing failures on both units' trip-oil systems.

Note that each of the steam-turbine control valves for HP and IP systems has a trip-oil line going to the actuator. Each trip-oil line applies pressure to a poppet valve allowing the actuator to stroke up and down. If this poppet valve is not completely closed, then sufficient control oil pressure cannot be maintained on the steam valves to allow them to stroke open.

In May 2023 when starting to roll the Unit 2 steam turbine, the HP and IP control valves would not open. The unit was brought down to investigate. Rexroth reps for the valve actuators brought onsite to troubleshoot found that varnish had built up on the HP and IP trip-oil poppet valves, causing them to stick open (Fig 2), thereby preventing the necessary control-oil pressure to be applied to properly actuate the valve.

The poppet valves were cleaned and reinstalled, costing six days of downtime to get personnel and tooling onsite. A week after the incident on Unit 2, the same issue occurred on Unit 1. However, this time site personnel were prepared with all proper tooling onsite and able to clean and replace the poppet valves in only five hours, thereby saving the plant days of forced-outage time (Fig 3).

Results. After numerous oil analyses and different filter combinations, Jackson Generation has all control-oil parameters below recommended guidelines. The permanent set up on the control-oil skid consists of fuller's earth filters with ion-exchange filters that are changed monthly. A nitrogen blanket system was also installed on the reservoir to eliminate any water ingress, which has the added benefit of drying out the head space of the tank. Oil samples are taken biweekly to assure varnish has not returned.

Project participants:
Corbin Shanklin and the Jackson Generation O&M departments

Share current drawings plant-wide to assist operations personnel

Challenge. Plant personnel use many tools to help them operate their facilities—especially P&IDs. Virtually every powerplant has a big binder containing the drawings for the entire facility. When a question or problem arises, staff brings out the "big book" and flips through numerous pages to find the correct one.

Another way to do this is to have the P&IDs in a digital format to facilitate the searching and highlighting required. However, it can be a nuisance to find the exact drawing needed if the P&ID library was not organized properly from the beginning of operations.

Yet another challenge: Retaining the most current revision of each drawing at the plant and being able to update it across the site. Be aware that you could have multiple departments using different revisions of the same P&ID.

Solution. At least one of Jackson's operators knew the plant's P&IDs could be organized in a more user-friendly fashion. Using his website-building skills he started putting together a plant-only P&ID website with all the revised EPC P&IDs and vendor drawings. The P&IDs are organized by system and can be filtered by vendor. The P&IDs can be linked, enabling you, for example, to start with the condensate P&ID and follow it all the way to boiler feedwater. Heat trace, electrical, and isometrics are included.

The website also serves as a master file, holding the most current revision of each drawing—including breaker schedules and electrical one-lines. The website is a critical troubleshooting and training tool.

3. Plant personnel remove and clean the trip-oil poppet valve

Results. All plant personnel have website access, saving time in preparing LOTOs and contractor work packets. The website also has proved a critical asset for conducting heat-trace audits and for repairing heat-trace circuits. All the drawings required for this effort are linked and organized. Because each P&ID is opened in Adobe so you have the ability to highlight and red-line the drawings.

Project participants:
Danil Klokov

Inlet-system maintenance critical to top performance

The Energy Information Administration reports that US electricity demand will increase by 25% within five years, requiring a significant increase in generating capacity, upgrades to existing assets, and improvements to grid infrastructure. But that's only part of the solution: Maintaining the current fleet of generation assets in top condition is vital to meeting projected demand.

The editors caught up with Dürr Universal's (https://www.durr.com) maintenance experts at a recent user-group vendor fair where discussion focused on the important role of gas turbines in balancing both current and future electric needs. The Dürr team noted that, in their experience, air inlet systems are among the most overlooked components in gas-turbine inspections.

This could be considered penny wise and pound foolish given that a well-maintained inlet system supports high turbine availability and efficiency while preventing costly downtime and equipment degradation. One of the most critical aspects of maintaining these systems, the Dürr experts said, is protecting against corrosion and coating failures.

Recall that the GT air inlet system typically has these five main sections:

- Dirty-air side, where unfiltered air enters.
- Clean-air side, where filtered and conditioned air moves toward the turbine.
- Conditioning system, if installed, may include evaporative cooling or fogging.
- Inlet plenum and silencer, which manage air flow to the turbine.
- Turbine inlet transition section, to ensure smooth air flow into the compressor.

Also, remember that most turbine inlet systems are constructed using coated carbon steel. Over time, these components can degrade, leading to rust, chipping paint, and metal deterioration. And when such debris enters the clean air stream it can affect critical components within the turbine proper.

Corrosion in GT inlets is particularly common in humid climates. Systems with evaporative coolers or fogging systems introduce humidity, increasing the likelihood of corrosion—especially if coated surfaces are not properly maintained or if the conditioning equipment is not operated correctly. Exposure to corrosive cleaning agents can also damage coated surfaces and accelerate metal degradation. Once coating systems fail, the exposed steel surfaces become vulnerable, resulting in increased maintenance costs and reduced performance.

To mitigate these risks, the Dürr Universal team recommends the following best practices:

- Regular inspections and maintenance. Conduct annual inspections to identify coating failures early, preventing minor issues from escalating into major repairs. Early detection of rust, peeling paint, and/or structural weaknesses allows for timely intervention and cost saving.
- Proper surface preparation. Before applying new coatings, ensure surfaces are thoroughly prepared to maximize coating adhesion and longevity.
- High-performance coating systems. Use industry-approved multi-layer systems—such as zinc primers, epoxy intermediates, and polyurethane topcoats—for long-term durability and resistance to harsh environments.
- Filtration system maintenance. Effective inlet filtration prevents contaminants from entering the turbine, reducing the risk of corrosion and fouling. A well-maintained filtration system not only prolongs coating life but also minimizes recoverable and non-recoverable degradation.

Investing in preventive maintenance and proper coating systems significantly reduces long-term expenses. Recoating a surface is far more economical than replacing steel structures compromised by extensive corrosion. Additionally, well-maintained coatings help improve efficiency, reduce downtime, and extend the lifespan of gas-turbine components.

As gas-turbine assets are called upon to operate longer and more frequently, it's more important than ever to partner with inlet system experts. Professionals providing comprehensive inspections, maintenance recommendations, and high-quality coating systems ensure your equipment remains in peak condition. They can tailor solutions for all inlet designs, focusing on local and environmental exposures to keep your units operating while minimizing downtime. CCJ


1. Evaporative cooler downstream framing before (left) and after (right) repair


2. Tubesheet before (left) and after (right) repair


3. Sump steel before (left) and after (right) repair

Nebras Power IPP1 Jordan

Owned by Nebras Power, Mitsui, and AES Corp
Operated by Nebras Power IPP1 Jordan

400 MW, gas fired with diesel-oil backup, 2 × 1 combined cycle powered by AE94.2 gas turbines, located in Al Manakher, Jordan

Plant manager: Feras Hammad

Removing moisture from steam-turbine lube oil

Background. Lube-oil quality is a major concern of O&M departments because of the fluid's importance in promoting long life of rotating parts and safety. Severe oil/water dilution occurred in IPP1's steam-turbine (ST) lube-oil system, the absence of continuous monitoring instrumentation and an alarm function on the LO system's console making it difficult to identify in the early stages of contamination.

Challenge. Prevent moisture from contaminating ST lube oil.

Solution. First step in mitigating the moisture intrusion problem at Nebras Power was to modify, as necessary, ports on the lube-oil tank to facilitate connection of the portable purification system currently serving the gas turbines. Next step was to test the effectiveness of that purification system on ST lube oil and record data for decision-making. Also, to purchase and install water high-quality detection instrumentation.

Water-detection effectiveness was monitored closely. Lube-oil quality was tested semi-annually and found acceptable.

In keeping with the plant's commitment to continual improvement, staff focused on upgrading the ST insulation and resizing of the oil seals to let steam escape and condense in the oil galleries.

Note that the steam-turbine lube-oil system was provided with an oil purification system capable of removing moisture, but its capacity was insufficient for the task at hand. Plus, it did not have a moisture alarm or automatic drainage function to eliminate any water collected.

An acceptable replacement was identified, purchased, and installed by AES personnel. No major modification of the existing purification system was required to accommodate the new one (Fig 1), which collects water from the bottom of the water separator by gravity. Isolation valves are provided for operation and maintenance. A connection to the DCS allows personnel to monitor system operation.

Results. The new purification system provides greater accuracy in monitoring lube-oil water content. Plus, the need for precautionary oil drainage by operators to identify moisture has been eliminated. Finally, the area is kept clean and oily waste has been reduced.

Plant staff is confident that water in oil will not exceed acceptable levels in the future and that lube-oil quality improvement will extend the lifetime of STG bearings.

1. Water is removed from lube oil by device shown in right-hand photo which was installed where indicated by red outline at the left

Project participants:
Sameer Ghanim
Issa Irshaid
Ali Hamed
Shaker Balawi

Replacing belt-driven fan drivers with VFDs reduces cooling-system O&M cost

Challenge. As supplied, the four fans providing cooling air for Nebras Power's closed cooling water (CCW) system each were powered by a 45-kW belt-driven motor. This design presented several issues when starting the fans—including these:

- High mechanical stress on both motor and fan components.
- High starting torque.
- High starting current.

Challenge was to identify a solution to reduce the noted impacts of the present starting system.

Solution. Key steps in developing the solution for improving drive-system performance and reducing O&M cost were the following:

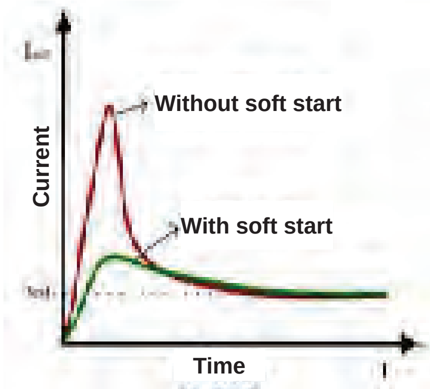
- Technical and financial evaluation.
- Communicate with suppliers and get a quotation for the equipment and work involved.
- Issue a management of change notice.
- Execute the plan.
- Check and monitor the modification.

Methodology and tools used to arrive at the solution are described in Fig 2. Fig 3 illustrates the advantage of installing soft-start.

Results included the following:

- Reduced mechanical stress.
- Extended equipment lifetime.
- Reduced the inrush current.
- Increased efficiency and saved energy.
- Reduced the cost of spare parts.
- Reduced O&M cost.

Project participants:
Mohammad Alziq
Mohammad Aldaher

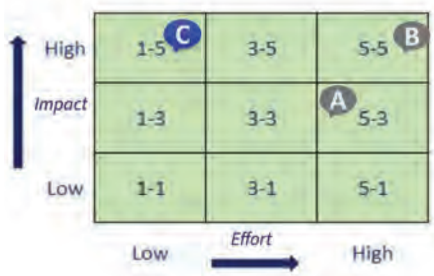


3. Soft start dramatically reduces the starting current and its associated wear and tear on the motor

METHODOLOGY

Plan	DO	Check	Act
Identify the current situation, to determine the cause	using (Effort /Impact Matrix) to implement the solutions	Measure the performance the modification	Start implementing /replication on the CCCW fans

Solution	Description	Effort	Impact
A	Modify the system to direct drive using gearbox	5	3
B	VFD	5	5
C	Install soft-start	1	5



2. The methodology used to assure success of the CCW system modification involved steps described in the four boxes immediately below and the evaluation chart to the right of them. First steps (A, B) were to replace the original fan motors with belt drives to variable frequency drives. Final step was to install soft-start capability (C).

AES Levant Power Plant

Owned and operated by AES Corp

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

Plant manager: Feras Hammad

Charge-air-receiver crack repair: welding versus epoxy paste

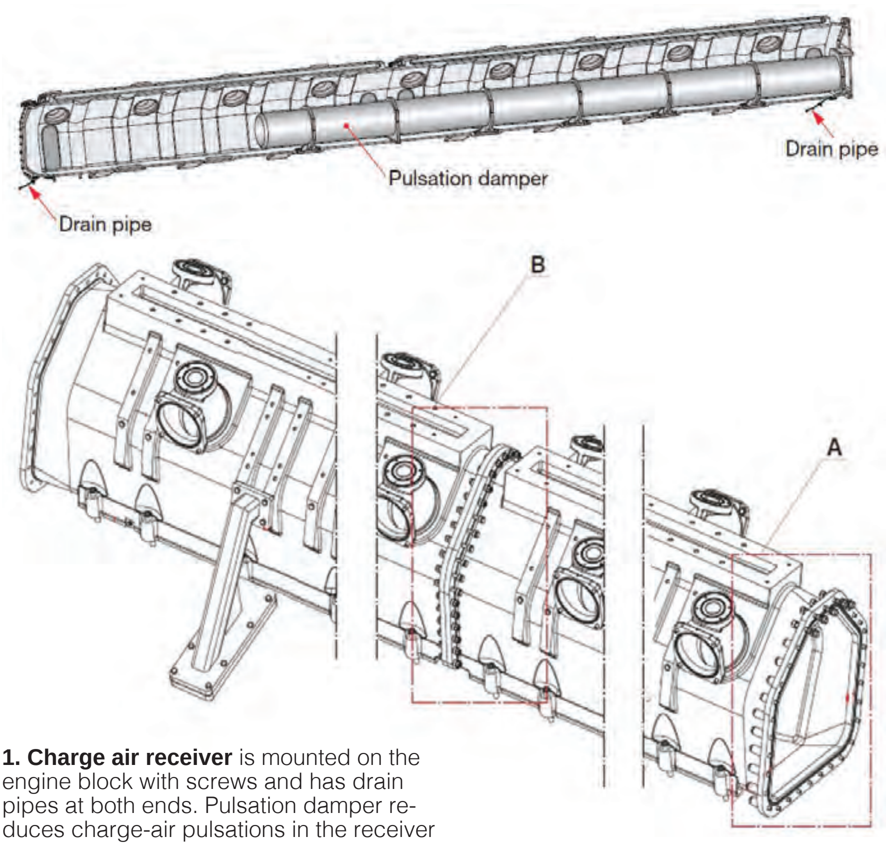
Background. Wärtsilä 18V50DF engines (16 in total) are the core components in the AES Levant Power Plant. The subject of this best practice, the engine charge-air receiver, is responsible for delivering and distributing intake air to all cylinders.

Challenge. Leaks in the air-intake system attributed to cracks in the charge-air receivers on 13 of the plant's engines adversely impacted performance, availability, and O&M budget (Fig 1). Plant staff participated in a brain-storming session designed to identify the optimal solution.

Solution. Two approaches were considered for sealing the cracks causing the leaks: welding and epoxy paste (Fig 2). The welding alternative was a relatively straightforward repair for Levant's skilled O&M staff. However, selection of the appropriate epoxy required a technical and financial evaluation (Fig 3). The manpower requirement for performing epoxy-paste repairs on the engines was estimated at $3000 versus more than $200k for the welding solution.

Results. The two-part epoxy paste selected for this application was Belzona 1161 Super UW-Metal and solidifier. Belzona has a history of successful epoxy applications in the electric power industry.

Project participants:
Laith Jara'abeh
Abdullah Al Dabaybeh
Raviarma



1. Charge air receiver is mounted on the engine block with screws and has drain pipes at both ends. Pulsation damper reduces charge-air pulsations in the receiver

'LFO filtration machine' improves fuel quality, boosts engine availability

Challenge. Water and sludge accumulation in fuel filters adversely impacted plant operation when fouling was severe and the engines transferred to backup mode (Fig 4). Clumps of fuel would be in evidence and the smell difficult to bear.

Solution. O&M personnel attributed fouling of the light fuel oil to inadequate filtration and purchased a MICFIL AL/ST 600 from Germany's MICFIL Ultra Fine Filters GmbH (Fig 5). Among its features are removal of particles over 0.5 µm, water absorption, and removal of about 98% of all bacteria. The filter is said to prevent abrasion in bearing shells, ball bearings, and all moving oil-lubricated parts in the engine as well as in the diesel exposed parts within injection pumps and single-tip nozzles—thereby promoting improved and cleaner combustion.

Results. Savings in materials costs and O&M time and effort amounted to more than $100,000 in 2023.

Project participants:
Sameer Abedrabboh
Ahmad Banihani
Osama Khamis

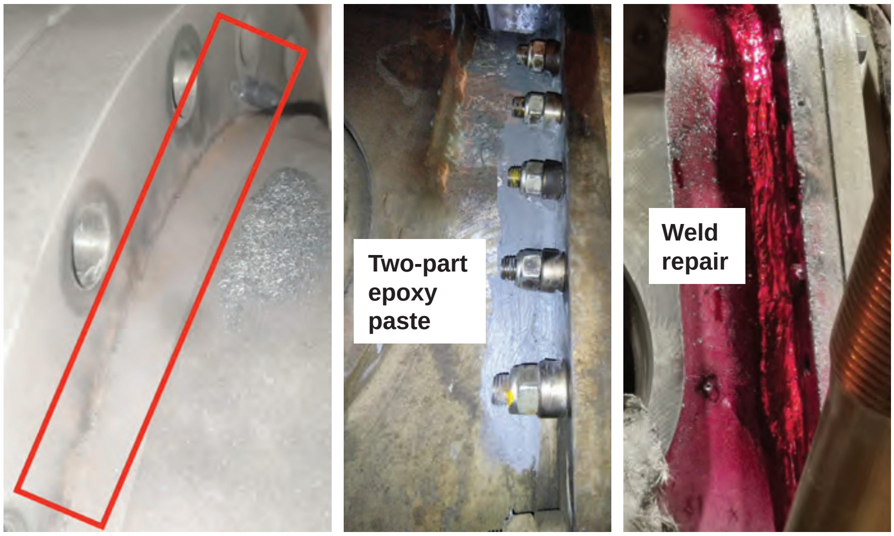
LED floodlights reduce O&M cost

Challenge. Reduce the power consumption and maintenance cost of plant floodlighting which suffered frequent defects.

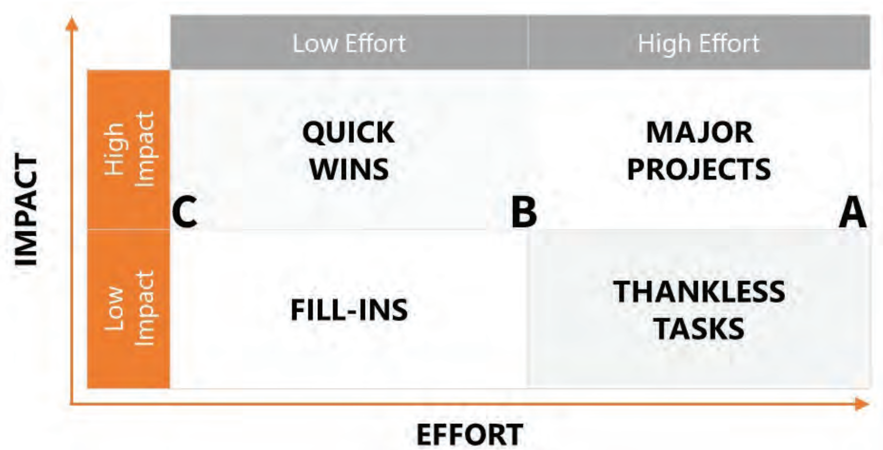
Solution. Transition from the existing incandescent lighting to LED (Fig 6).

Results. Annual energy cost for lighting was halved and the annual material cost was reduced by three-quarters. Data were not available regarding the saving in maintenance cost.

Project participants:
Ashraf Qasim
Ayman Mobaied



2. How to deal with the crack at the base of the air-receiver flange challenged plant personnel. The alternatives: welding and a two-part epoxy paste. The crack is shown at the left, the two-part epoxy paste applied to crack area is in the center photo, welding is at right



3. Methodology developed during staff brainstorming produced the impact/effort matrix illustrated here. Charge-air-receiver (CAR) replacement (A) requires a Level 5 effort, but delivers a Level 5 impact; CAR welding (B) produces a Level 3 impact for a Level 3 effort; epoxy paste is the simplest solution, requiring only a Level 1 effort for the same Level 3 impact as welding

4. Fouled fuel filters adversely affect plant availability and engine reliability while adding to the time, effort, and cost of operation and maintenance

5. The so-called LFO filtration machine requires little floorspace and is said by other users to have a long service life

6. New plant floodlights give the appearance of daytime at night

Quail Run Energy Center

Owned by Starwood Energy Group Global
Operated by NAES Corp

550 MW, two 2 × 1 7EA-powered combined cycles equipped with A10 steam turbines, located in Odessa, Tex

Plant manager: Andy Duncan

Cooperation on water use benefits both power generator, industrial neighbor

Background. Upon learning that a dig permit had been issued for property close to Quail Run, plant management arranged a meeting with the permit holders who said they would be digging wells to provide water for fracking in the oil-rich Permian Basin.

Plant's concern was water availability given that it too was searching for additional water sources for a future project. Many in the region use well water to support fracking and oil production.

Challenge. Assure adequate water resources to support plant operations in the future.

Solution. An internal study determined that Quail Run's cooling-tower blowdown meets the chemistry requirements for both fracking and production water. Next step was to work with the Texas Center of Environmental quality to get the authorization needed to send cooling-tower blowdown water to the oil production facility.

Permission granted, the plant partnered with a local company that supplies well water for oil production. Result: Quail Run sends that company tower blowdown for use in oil production and it provides the plant good-quality well water for tower makeup.

Results. Winners all: The amount of blowdown sent to the wastewater processing facility was reduced, the amount of city water supplied for tower makeup was reduced, and the quantity of good well water used in oil production was reduced.

Project participants:
Andy Duncan, plant manager
Plant staff

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