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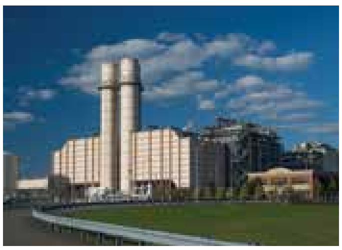
USERS 501F GROUP

501G USERS GROUP

Best Practices Awards


Valley, p 40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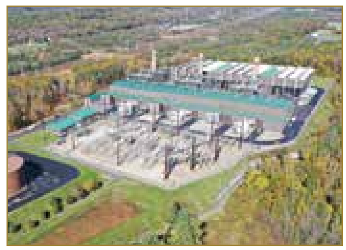
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INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

Five plants earn Best of the Best honors in CCJ's annual Best Practices Awards program

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Operated by NAES Corp

CPV Valley Energy Center
Owned by Competitive Power Ventures and Diamond Generating Corp
Managed by Competitive Power Ventures
Operated by DGC Operations LLC

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Operated by NAES Corp

Edgewood Energy LLC
Owned by J-Power USA Development Co
Operated by NAES Corp

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Owned by Minnesota Municipal Power Agency
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Hill Top Energy Center
Owned by Hill Top Energy Center LLC
Operated by NAES Corp

Hunterstown Generating Station
Owned by LS Power
Managed by Competitive Power Ventures
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Indeck Niles Energy Center
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Operated by PIC Group Inc

Jackson Generation
Owned by J-Power USA Development Co
Operated by NAES Corp

Long Ridge Energy Generation
Owned by Long Ridge Energy & Power
Operated by NAES

Mariposa Energy Project
Owned by Diamond Generating Corp
Operated by DGC Operations LLC

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Owned by Mashav Initiating and Development
Operated by Mashav Energy

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Operated by Nebras Power IPP1 Jordan

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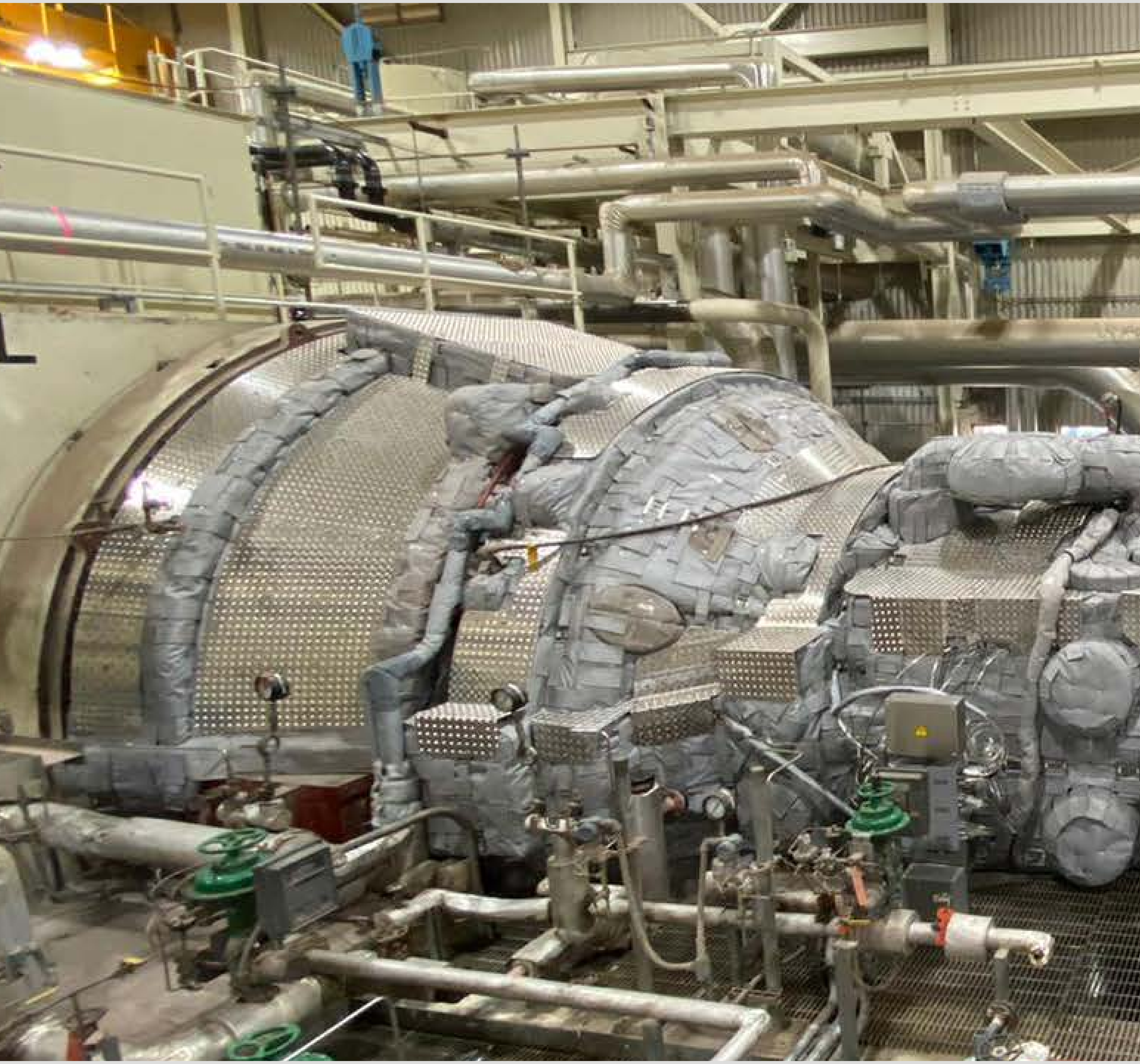
Advanced Single Layer Steam



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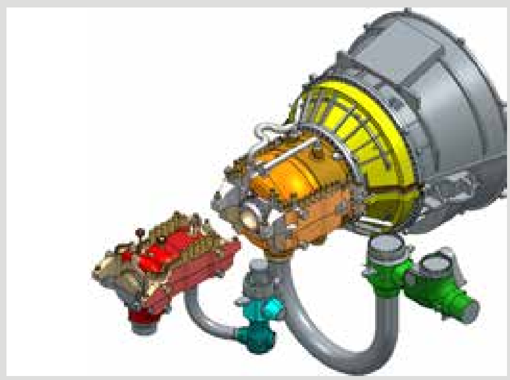

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Attend the 2025 conference, Feb 9-14 • Tucson, Ariz
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Owner/operators of 501F and 501G gas turbines co-located at Disney World's Coronado Springs Resort in Orlando, Fla, for their 2024 conferences, Sunday February 4 through Thursday February 8.

Sunday's program featured social events for all attendees. The agenda for Monday—including a safety roundtable, vendor presentations (a/k/a Vendorama), reception, and vendor fair—also brought together the 501F and 501G Users Groups. The organizations met independently on Tuesday, Wednesday, and Thursday for technical presentations by users, services providers, and OEMs.

The technical meeting got underway after breakfast Monday with welcomes by the user-group chairs, steering-committee members, and conference sponsors. A review of the user website by Chad Boschert and conference instructions preceded the annual safety roundtable. Half-hour vendor presentations began in mid-morning, arranged in seven sessions, with five presentations conducted in parallel during each session.

A busy first day ended with a vendor fair and reception from 4 pm until 7:30, giving owner/operators the opportunity to peruse the products and services offered by scores of companies with interest in the 501F and 501G fleets.

Agenda highlights for the F frame's portion of the 2024 joint meeting are summarized below. The program, developed and moderated by the steering committee, focuses on the operation, maintenance, inspection, troubleshooting, repair, and optimization of equipment in generating plants powered by 501F, 701F, and SGT6-5000 gas turbines made by Siemens-Energy, Westinghouse, and Mitsubishi Power.

Tuesday, February 6: Outage execution roundtable and user presentations, Siemens-Energy's presentation to users, and Mitsubishi Power's presentation to users.

Wednesday, February 7: Inlet and exhaust, rotor, and hot-gas roundtables and user presentations, and PSM's presentation to users.

Thursday, February 8: Auxiliaries, steam turbine, compressor, and generator roundtables and user presentations.

User presentations

A dozen-and-a-half presentations by owner/operators were incorporated into the outage execution, inlet and exhaust, rotor, hot gas section, auxiliaries and operations, steam turbine, compressor, and generator roundtables at the 2024 conference for 501F and 501G users. Summaries follow, with the objective of providing enough information for you to decide if the content of a given presentation should be reviewed in greater depth.

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If that's the case, access the PowerPoints of interest at https://forum.501Fusers.org. But be aware that you must be a registered user to gain access. If not, you can begin the registration process with a simple mouse click. CCJ readers who already are registered will find the presentations in the folder "2024 Conference Materials." (Click on the magnifying-glass symbol at the top right-hand side of the page.)

Magnetic case measuring sticks

Simple to make in the plant shop with self-adhesive measuring tape, aluminum bar stock (0.125 × 0.750 × 48 in. recommended), and 18-lb rubber-coated magnets. How: Cut aluminum to 24 in. and chamfer sharp edges; bend offset so measurement section remains flush against the case; install measuring tape with zero at the start of the flush section. Benefit: Hands-free measurement during turbine case removal and install, thereby protecting personnel.

Outage lessons learned during first majors for a 2 × 1 combined cycle powered by 501FD2 gas turbines

- Unit tripped post outage because two blade-path thermocouples failed; attributed to insufficient cooling-air flow.
- Burner "C" stage flange on an Alstom steam generator was over-torqued, leading to a gas leak not detected during pre-startup testing. Same issue was later identified on other burners as well.
- High turbine backpressure was a result of clogged traveling screens, condenser waterboxes, and piping attributed primarily to improper intake dredging.
- Hook-fit wear issues were experienced, but repair details had not been provided by the OEM prior to the meeting.
- Several unit trips on restart were attributed to high blade-path spread. Causes included failure to follow proper storage procedures for fuel-gas piping during the outage and not inspecting the piping be-

fore reinstallation.
- Debris found in new parts clogged air passages.
- Multiple stuck/trashed generator coupling bolts required destructive removal and replacement.
- Blast cleaning on the first HRSG damaged several baffles, delaying restart.

W501F torque-tube replacement considerations

A torque-tube failure can take a plant out of service quickly and for a long period. According to industry statistics quoted in this presentation, the W501FC and FD1 fleets, encompassing some 256 units, had experienced 19 "unplanned events" attributed to torque-tube cracks by fall 2023. This topic has been included in the technical program of annual 501F meetings for many years.

To review, (1) crack propagation is via high-cycle fatigue, (2) failure can occur in as few as 20 starts after crack detection, (3) failure is identified by way of vibration signature and eventual inability to run because of high vibration levels.

The speaker said it makes good sense to upgrade the rotor to address compressor issues and reduce outage time—typically about 30 days assuming all parts are on the shelf and appropriate for installation. The risk of replacing the torque tube without upgrading the compressor could mean another rotor pull during a major inspection.

Lots to consider. For example, torque tubes are a long-lead-time component and not stocked by most vendors. Thus, if you have a unit considered susceptible to torque-tube failure based on hours, starts, and other factors, you might want to order one before a problem arises. Another possible sticking point: Some vendors will not sell a torque tube without its installation as part of the package.

Rotor-swap alternative: Torque-tube replacement takes about four times longer than a rotor swap, so there's at least one alternative to consider. Keep in mind that project cost and the value outage time are key variables to factor into your decision.

Inlet/bellmouth/IGV maintenance considerations and a quick dive into compressor coatings

Good filtration, plus the condition of your filter house, inlet, bellmouth, and inlet guide vanes, are important to the overall health and performance of your gas turbine. Virtually all experienced operations personnel know this, but some technicians are prone to taking shortcuts and some supervisors are not as hard-nosed as they might be.

Presentation offers best practices and guidelines to review over lunch in the break room. What to look for on rounds, for example. Service Bulletin SB4-13-0037-GT-EN-01, and Service Bulletin 51004-R2 on inlet guide vane maintenance, are highly recommended. The latter was billed by the speaker as

Hands-free measurement during casing lifts

Use of Siemens-Energy's upgraded hardware facilitates removal and replacement of generator coupling bolts, nuts

Maintain the clean side of your filter house to avoid throwing away time and money on filter changeouts

Lubricate inlet guide vanes during your annual borescope inspections

Remember to verify linkage thrust force after lubricating your IGVs

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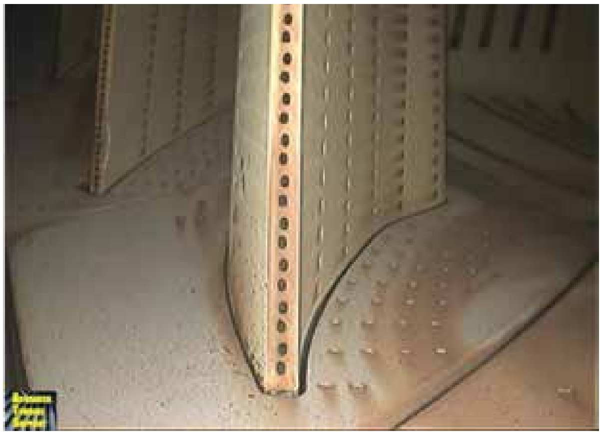
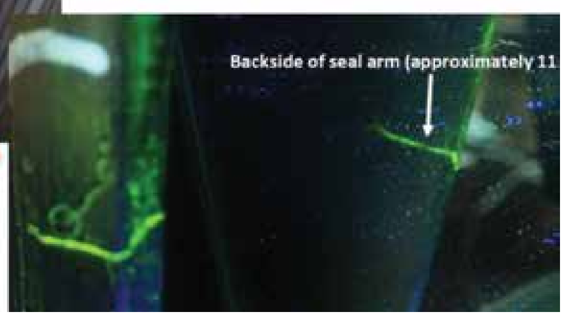


Advanced first-stage vanes in GTOP system remain pristine after two years of service

Loss of finger seals early in life of this FlameSheet combustor was surprising

Excessive base-metal oxidation in Rows 2 and 3 encouraged the unit owner to plan for blade-ring exchanges

Rotor alignment was one of the challenges faced after replacing Row 3 interstage seals



Crack found in Row 2 was excavated, then blended using a 5:1 ratio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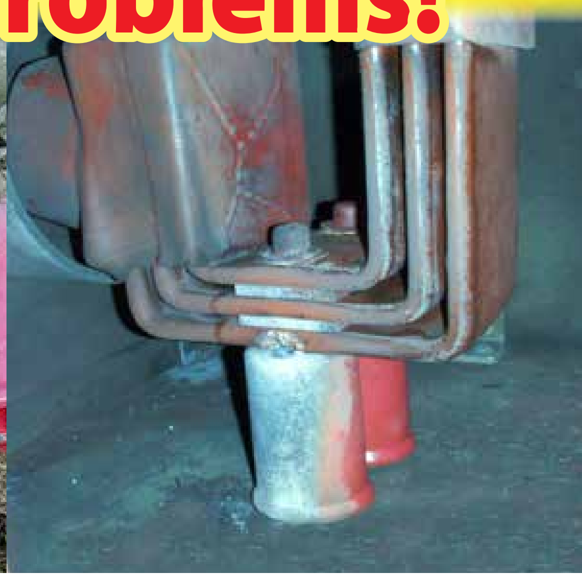

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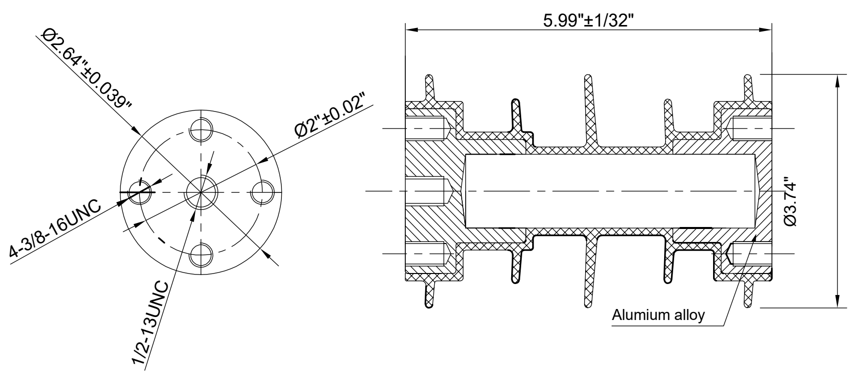
Torsion strenth...2900in-lbs
Min creepage distance...11.8inch
Acring distance...6.14inch
The color of weather sheds is light gray

Standard applied: ANSI C 29.1

2.5lb



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Airfoil smoothness and erosion/corrosion avoidance was a major part of the discussion. Coatings often are the key here and that is covered in the slides with mention of base, intermediate, and top coats, surface roughness goals, and applicable ASTM standards.

M501F IGV maintenance and troubleshooting

This maintenance and troubleshooting guide for M501F inlet guide vanes includes a few slides pertaining to the W501, so it's representative of the 501F fleet. The editors rate the presentation "valuable" for its detail, recommending it be included in the plant O&M library.

The speaker's notes based on experience at his plant include the following points:

- Lubricate the IGVs annually, during the borescope inspection.
- Linkage thrust force has been a problem.
- Unison rings/rollers have shown clear signs of skidding.

The IGVs are grease-lubricated with Mobil EP 0—typically two or three gun pumps per vane; vane tip clearance is checked shortly after lubrication. Topics include target clearance, "burping" of the IGVs, linkage thrust-force verification, roller issues, IGV component enhancement, and IGV roller bushing upgrade.

Point stressed: A robust maintenance plan is critical for reliable operation of the IGV system, regardless of the OEM.

33k hardware review (FD3 and F4)

Twenty-slide deck is photos only, no type! Value is in staff preparation for an outage to explain what to look for and what to do when you find it. Photos are of pilots, support housings, transitions, baskets, turbine blades for Rows 1-4, vanes for Rows 1 and 2, and ring segments for Rows 1 to 3.

GTOP advanced component life experience

A rapidly evolving balancing area encouraged the retrofit of PSM's FlameSheet™ combustors on two W501FD2 engines. Owner needed more power to support residential and industrial growth attributed to immigration, and better turndown to accommodate massive solar adoption.

In addition to the new combustors, PSM's GTOP 7.1 system was installed to help boost output and extend maintenance intervals. It featured new 16th-stage compressor blades as well as first-, second-, and third-stage HGP components. Regarding controls upgrades, PSM's AutoTune 3.0 was retrofitted.

Mods were made to the first gas turbine in November 2020, recording 12,631 hours and 363 starts through 2023. The second GT was upgraded in April 2022, recording 8217 operating hours and 239 starts by year-end 2023.

Photographs shared confirm generally excellent condition of HGP parts on both engines at the end of 2023, except for some rubs and platform coating issues on first-stage blades and minor rubs on R2 blades.

The owner/operator reported no trips concerning loss of flame, disc cavity, or any other mod-related issues.

FlameSheet challenges—one plant's experience

FlameSheet upgrades on two W501FD2 engines serving a combined cycle included the installation of 16 new combustors (per unit)—each can with its own ignitor (crossflame tubes were removed), one CDMS probe, and two flashback thermocouples. Plus, all new fuel-gas pigtails.

Startup issues associated with the first unit are detailed. One problem was a damaged pilot cartridge that was revealed in a borescope inspection after personnel couldn't tune the engine.

Several flashback events were recorded, requiring removal and disassembly of all cans as described in photographs. All finger seals were replaced along with six flow sleeves.

M501F3 turbine-blade ring exchange challenges and lessons learned

Would be a leading contender for a "best-paper" award, if there was one. Owner/operator planning the major inspection of the second unit (No. 8) in the 2 × 1 combined cycle profiled relied on past experience for guiding critical hot-gas-path (HGP) decisions. Operating data: 58,500 fired hours, 1628 fired starts, 54,800 turning-gear hours.

Row 2 turbine blade ring for No. 8 was exchanged during the unit's 2019 HGP because of excessive base-metal oxidation and circumferential deformation. R3 had significant oxidation throughout the entire blade ring but was only weld-repaired. On the sister unit's (No. 7) major in 2020, R2 was exchanged because of severe base-metal oxidation and material loss while R3 distortion was corrected in the OEM's shop. Based on this experience, the utility planned to replace the R2 and R3 blade rings during the Unit 8 major.

Outage-planning highlights and notes and photos of the as-found condition of R2 and R3 for Unit 8 are provided in the slides, along with blade-ring assembly challenges important to users with similar issues.

Interferences between the geometry of the ring-segment retaining lugs and blade rings were found as well and are discussed, in addition to issues with the blade-ring horizontal ledge keys that prevented horizontal joints from closing properly. R3 interstage seal alignment was another problem encountered. It made rotor alignment difficult and was resolved by sacrificing side-to-side spindle clearances.

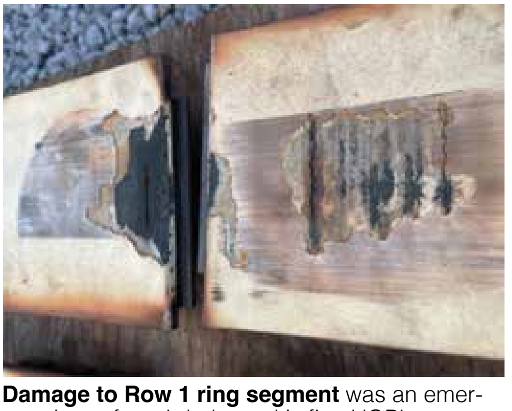
Recommendations to others facing similar challenges included the following:

- If a blade-ring exchange is planned, explore the possibility of having it shop-assembled.
- Maintain close vigilance of technical details. Even the OEM and competent service providers can miss important items that can have a negative impact on schedule and manpower.
- Obtain all refurbishment and pedigree information up front.

Finally, remember that just because a component is able to pass QC in the shop, it doesn't mean that it is in appropriate condition for entering service.

M501F return-to-service issues post HGPI

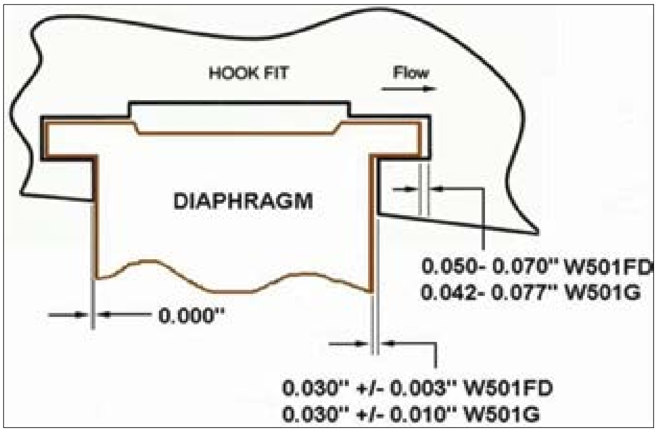
Emergent issues encountered during HGP and generator robotic inspections for two F4 units, and the thought processes used to re-



Damage to Row 1 ring segment was an emergent issue faced during unit's first HGPI

Field tipping of Row 1 blades was cited for dealing with rubs

Machining the face of the tubesheet helped restore the condition of this kettle boiler



Critical hook-fit measurements for making repairs

Timely turbine exhaust repairs are important for keeping O&M costs in check

Hook-fit issues also were discovered on this M501F3

solve them, are covered in this presentation with input from a plant operations manager and engineers from two engineering organizations. Borescope inspection results and vibration signature analysis are included in the slide deck. Ring-segment issues, combustion challenges, rubs in the turbine section, and spin cooling also received air time.

Field tipping R1 blades

Causes of rubs and ways to prevent them are discussed. Takeaways on how clearances are checked and calculated, plus the process and hygiene of tipping, are focal points of the presentation. Of greatest value to users, perhaps, is the list of references provided covering tipping, optimizing of clearances to mitigate ring-segment rubs, hot-restart guidelines, spin-cooling guidelines, and details on the design, upgrade, and O&M of the direct air injection system (DAIS).

FlameSheet NOx issues—one plant's experience

This is the second of three presentations on FlameSheet experience by one of the three 501F owner/operators so equipped. Mode 3 fuel splits and mode transfers are the presentation's focus, with stack emissions shown in one slide. This customer's opinion: FlameSheet is running well and PSM has been a responsive partner, but the technology still is relatively young and there have been the expected growing pains.

Increasing the service lives of kettle boilers

While Mark Dwileski, president, Northeast Precision Welding, is not a user, the steering committee chose to include his presentation in this portion of the 501F and 501G program, likely because he is well known to owner/operators and helps them solve difficult welding problems. Kettle-boiler and exhaust-system repairs are two of NPW's specialties and Dwileski covers both in a presentation encompassing some 80 slides.

FlameSheet learnings continued

This is the last of three presentations on FlameSheet experience by one of the three 501F owner/operators so equipped. However, it offers little detail on the controls changes the speaker says are needed to adapt what he considers a GE-centric combustion design to the 501F. A mismatch between the D11 steam-turbine's metal and steam temperatures (too-hot steam) made it impossible to start Unit 2 after the GTOP outage.

Siemens 501F, G, and D5A compressor case diaphragm hook-fit history and repair process

Compressor casings, diaphragms, and seal holders experience hook-fit wear. Over time, such wear can be excessive (most pronounced at the compressor horizontal split line) and, if not addressed, seal-holder migration in the forward direction can lead to contact with the rotor disc face. Result: Liberated material in the form of rotating airfoils and excessive foreign object damage.

Advisory: The hook-fit repair process requires different levels of skill from accurate measurement-taking, preparation, welding, and final machining. Not all welders and not all machinists have the skills to perform this repair properly.

M501F3 compressor hook-fit wear found during a major inspection

Experience gained on hook-fit repairs during the major inspection for Unit 7 three years earlier was factored into the outage planning for sister Unit 8. A diagram shows where most wear occurred on U8, requiring 1061 linear inches of repairs. Photos illustrate the repairs made.

Additionally, compressor diaphragms for

Generator coolers challenged by corrosion and sludge buildup were replaced. Here's how

Parallel ring tangs for certain Aeropac generators were discussed with regard to the connection surface and brazed connection at the parallel ring

Rows 5 through 14 were recommended for repairs. Rows 5 through 8 were considered low risk and allowed to operate as is. Wear and tear in Rows 9 to 14 was judged to be of moderate risk and those diaphragms were replaced.

R3 compressor diaphragm was replaced because of damage incurred from a liberated seal-box retention setscrew. Foreign object damage to R3-4 rotor disc was the final topic covered.

Generator through bolts, mini-link replacements, and parallel-ring tang inspections

Subsurface indications in through bolts for four identical generators installed at two facilities were addressed by the speaker. All four have had sleeves and spacers installed and have the bolt capture device. Bolt replacements are planned during next majors.

Mini-link replacements and parallel-ring tang inspections also were discussed.

Aeropac cooler replacement

Coolers for the Aeropac generators serving the 501FD3 gas turbines at this 2 × 1 combined-cycle cogeneration plant suffered from a heavy sludge buildup in their 0.750-in. vent and drain lines, plus heavy corrosion of their 6-in. inlet and outlet pipes. Well-illustrated presentation records removal of the original Unifin coolers and their replacement with new Kelvion coolers.

Only minor modification of the vent and

Foreign object damage took a bite out of this Row 2 compressor blade and damaged several more downstream blades, but less severely

drain lines was required for fit-up. Plus, new two-piece P-seals were installed on both coolers. Pressure test was performed with water at 65 psig and held for 15 min to ensure no leaks were found at connection points.

Compressor foreign-object damage

Presentation describes the combustion inspection experience of a 501FC+ that powers a 1 × 1 combined cycle. The unit's original rotor had operated for nearly 73,500 hours and 4800 starts at the time of outage profiled in spring 2023. Duty was intermediate peaking service.

There was no indication or suspicion of compressor damage prior to the 14-day outage. Vibration levels were normal. Yet the damage staff found when the machine was opened required the replacement of 19 blades and blending of 224 others in Rows 1 through 11. Additionally, blending was required on 50 diaphragms. Staff had no knowledge or indication of when the incident occurred.

One possible explanation (unofficial): Icing.

Eight photos of the damage are included in the slide deck.

Vendor presentations

Access the presentations summarized below at https://forum.501Fusers.org. But be aware that you must be a registered user to gain that access. If not, you can begin the registration process with a simple mouse click. CCJ readers who already are registered will find the presentations in the folder "2024 Conference Materials." (Click on the magnifying-glass symbol at the top right-hand side of the page.)

Generator update and trends

National Electric Coil

W Howard Moudy, director of operations

Howard Moudy, well known in the user community for his generator expertise, kicked off the 501F/501G Vendorama program on Feb 5 at 10:20 am with an hour-long presentation updating attendee knowledge of generator issues and concerns by model, key maintenance factors, lifecycle planning, and life-extension trends and concerns.

Focus was the Siemens Aeropac I, with Aeropac II, TLRI, and Westac also covered; Brush BDAX units; and Alstom WX/WY (GVPI). Most of these machines are air-cooled, with many approaching their 30-year design life. Speed cycling is typical for these generators, as are looseness and resonance issues in their endwinding support systems.

Moudy summarized the specific issues associated with each model, offered maintenance and diagnostic guidance, and solutions for the most common problems. Complete with photos.

The life-extension and trends segment of his presentation covers GVPI rewinds and repairs, GVPI stator core cleaning and preparation, proper support of TE and EE windings, insulation options, tangent delta testing, and inspection.

In-situ compressor blending for 501F, 501G, and J-class gas turbines

Advanced Turbine Support

Michael Hoogsteden, director of field services

Borrowing a theme from an old financial-services commercial, the editors believe it's not a stretch to say, "When Mike Hoogsteden speaks at a user-group meeting most attendees listen—and carefully." He and his colleagues at Advanced Turbine Support may have performed more gas-turbine inspections than any other non-OEM company over the last 20 years. It's not a stretch to believe they've seen virtually every type of damage inflicted on an engine using their borescope, visible/fluorescent dye-pen, mag-particle, phased-array UT, and eddy-current inspection capabilities.

However, inspection was not the topic of Hoogsteden's presentation in the 501F/501G Vendorama program. Rather, he discussed the value to owner/operators of in-situ blending for repairing damaged airfoils. Hoogsteden began by reminding participants that the purpose of blade blending is to remove stress concentrations or cracks

National Electric Coil. Focus is the Siemens Aeropac I, with Aeropac II, TLRI, and Westac also covered; Brush BDAX units; and Alstom GVPI. Photo shows GVPI stator-core cleaning and preparation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Advanced Turbine Support. In-situ blending mitigates the possibility of further damage, saves time and money by minimizing the extent of unit disassembly required

that can result in extensive damage to compressor components if a blade, or pieces of it, liberate. The ability to do this work in-situ saves considerable time and money by limiting the extent of unit disassembly required to make the repair.

Over the last several years, the capability of tools and techniques for in-situ blending have improved manyfold (see before/after blending photos nearby). Here's an update: In-situ blending of 501F/501G compressor rotor blades (B) and diaphragms (D) has been expanded to include all variable inlet guide vanes to Row 7 (limited success to R8D), with access via the bellmouth.

Depending on unit configuration and the ability to remove air extraction piping (or the borescope plug), all R10 and 13 rotor blades (with rotor rotation) can be added to the success list. Plus, limited success in 10D, 11B/D-13D, 14B/D and 16B (leading edge only).

Proactive SCR/CO system management for lower emissions and operating costs

Environex Inc
Andy Toback, project manager

Environex. Proactive SCR/CO system management benefits include lower emissions and operating cost

The proactive approach espoused by Andy Toback for achieving top performance from your emissions control system requires timely inspections and ammonia testing, plus judicious catalyst sampling and ongoing analysis of operating data. Factors that contribute to poor performance include non-uniform gas flow, NH3/NOx ratio, and temperature. Catalyst deterioration is another reason—often attributed to K, As, Na, Ca, and SO2 poisoning.

Proper plant operation is important to prevent such other bad actors as insulation blockage, exposure to moisture, poor/damaged seals, poor control of ammonia, and gas bypass of the catalyst. Photographs and data plots drive home important points.

Advancements in repair: Understanding materials, designs, and coatings for extended service

Doosan Turbomachinery Services Inc
Dr Scott Keller, director of engineering

A variety of factors can lead to the rejection/scrapping of individual components during a visit to a repair facility—including damage, distress, and/or exceedances of OEM lifetime limits. In many instances, used or refurbished replacements are not available or ready in time to complete the overhaul.

Not a problem for DTS. Its knowledge of materials, designs, and available coating options, and shop capabilities, allows the company to manufacture parts in timely fashion to replace scrapped components and provide a new lease on life for capital assets.

Based on customer requests and repair experience, Doosan has pursued the development of replacement hardware for compressors, rotors, and associated bolting, plus exhaust systems. An update on the manufacturing status of compressor airfoils, turbine discs, rotor components, rotor bolting, and other components is provided in the presentation, which also includes findings during recent overhauls.

Complete cycle solutions

ARNOLD Group
Pierre Ansmann, global head of marketing, and Norman Gagnon, project manager

The duo focused on steam-turbine and HRSG warming solutions for significant combined-cycle startup improvement. They began by reviewing the advantages of steam-turbine warming—including increased in-market availability, lower startup costs, reduced thermal fatigue and a longer mean time to repair for critical components, and greater operating flexibility.

Next, they reviewed alternative warming-system arrangements, rejecting those integrating the heating circuits in insulation blankets, installing the heater on a thin mattress below the blanket, and using glass-fiber-insulated heating cable. The optimal system for the upper casing, Gagnon said, is heater on metal mesh baffle, for the lower casing, permanent mounting of heating cable below the split line.

Ansmann noted that the ARNOLD warming system can maintain your turbine in a hot-start condition for at least four or five days after shutdown. No preheating of the turbine is required prior to a start within this time period, reducing startup fuel consumption and auxiliary power.

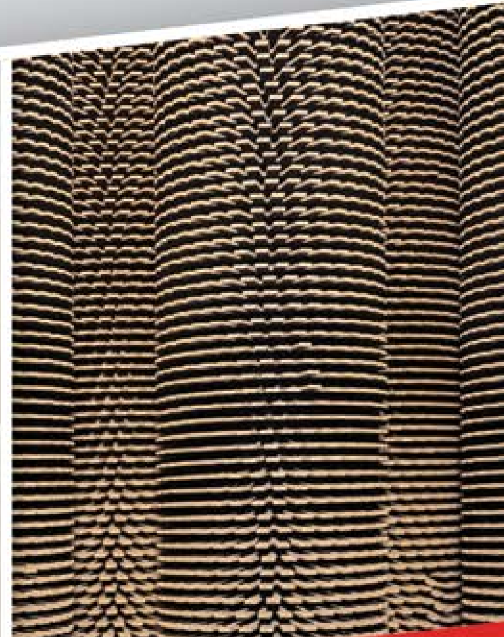
Other talking points included the following:

- Installation procedures. Total install time, depending on unit and mechanical scope, is from 30 to 50 days.
- System logic and communication with the plant DCS.
- Case studies from reference sites with dif-

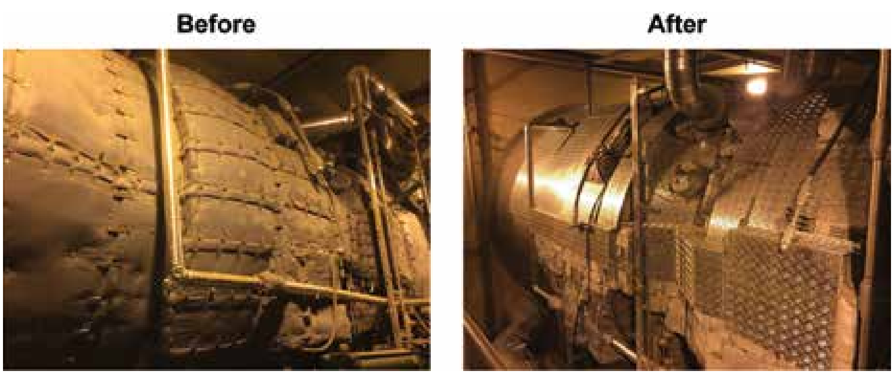
Doosan Turbomachinery Services. New exhaust cylinders (standard two-piece configuration) and exhaust manifolds in production enable in-kind replacement with DTS enhancements

SCR CATALYST CLEANING

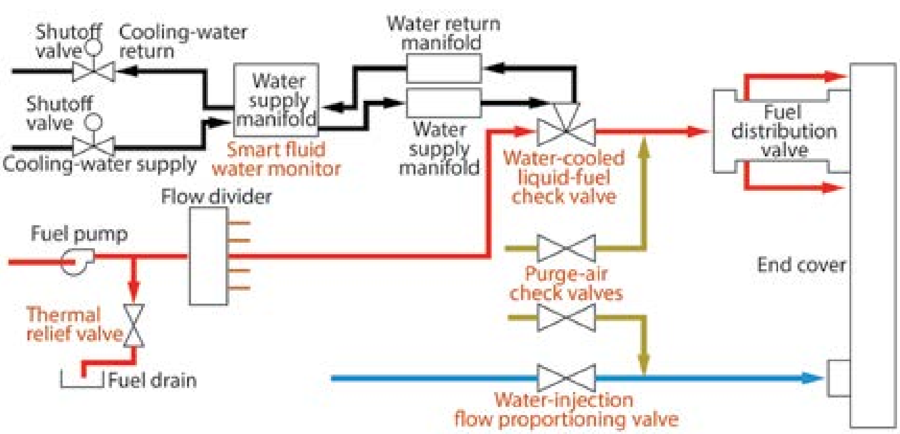
CO CATALYST REPLACEMENT



HRSG FIN TUBE CLEANING



ARNOLD Group single-layer insulation system (right) replaced OEM's premium insulation (left) on 2 × 1 501FC-powered combined cycle, reducing blanket surface temperature from 128F-302F to 97F-101F



JASC third-generation fuel-system improvements. System shown is for GE F-class engines with a fuel distribution valve. Components in color are designed and made by JASC

ferent steam-turbine models—including tandem- and cross-compound machines.

- Savings in startup fuel consumption, CO emissions, demin water, and staffing (less overtime).

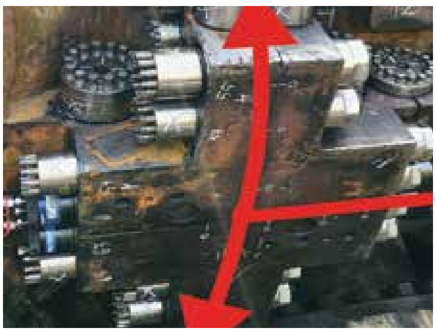
Dual fuel reliability: Optimizing system capability for reducing fuel and maintenance costs

JASC
Kevin Deutscher, VP

Operating reliably on backup liquid fuel is one of the most challenging tasks facing gas-turbine owner/operators. Deficiencies in valve design, high-temperature impacts on stagnant fuel, and issues with fuel-system balance-of-plant configuration all play a role in limiting the success rate for starting and/or transferring to liquid fuel.

Multifaceted problems require comprehensive solutions—such as valve designs that remain coke-free during extended operation on gas, and the ability to minimize the impact of temperature on fuel within piping located in the turbine compartment. They make it possible to achieve a level of performance that allows the liquid-fuel system to be exercised at greatly reduced intervals without degradation of start and transfer capability between combustion inspections.

The heavily illustrated presentation reviews the broad array of products JASC offers for liquid fuel, purge air, and water injection systems. They rely on water cooling of fuel controls, toggle-action valves, and valves capable of providing ANSI Class 6 bubble-tight performance. Two decades of experience on hundreds of turbines are



Nord-Lock Group's superbolts are a multi-jackbolt tensioner that replaces the OEM's nuts on its studs. The MJTs are tensioned starting at the 4-way joint intersection of the turbine and combustion cylinders, with tensioning continued while moving away from the joint

shared with users.

Distribution effects on SCR system performance

Vector Systems Inc
Vaughan Watson, director of sales and marketing

Focus of the presentation: AIG (ammonia injection grid) design fundamentals and the latest advancements in technology to improve SCR performance and ammonia consumption. Topics covered include common design and operational issues plants are facing—such as fouling and plugging, traverse and test-grid tuning, as well as the retrofit of improved designs to increase efficiency.

501F four-way joint solution installation

Nord-Lock Group
Peter Miranda, global business development director

Nord-Lock partnered with a 501F user on an R&D project to investigate 4-way-joint leak issues with the goal of finding a fleet-wide solution. The partners consider remedying leakage issues important to the protection of both personnel and critical equipment. A comprehensive testing program identified, then validated on several units, an effective solution—one that combined multiple Nord-Lock products and technologies.

Given the multiple contributing causes of 4-way joint leakage, the most effective solution identified combines a specific mix of products and technologies. The combination works in concert to address multiple potential failures and provides the following advantages:

- To quickly assess and manipulate cylinder alignment, the solution includes a Boltight™ hydraulic closure system (HCS). This ensures the 4-way joint is tensioned, temporarily, to conduct a proper alignment check of the cylinder—one similar to a tops-on/tops-off alignment check performed on steam turbines.
- If the bolt hole or flange is misaligned, a proprietary CamAlign tensioner system is used to realign the cylinder. System can close an internal gap of by 10 to 15 mils after the cylinder has been "squeezed" by the HCS—to ensure the smallest possible gap is achieved.
- The HCS is pressured up to simultaneously and uniformly squeeze the turbine cylinder around the 4-way joint—thereby isolating the area. Multiple hydraulic tensioners remain pressured up while internal and external gap readings are recorded, and cylinder alignment is checked.
- Once adjustments are complete and the 4-way joint is aligned properly, the joint is squeezed again using the HCS, which allows load transfer to the Superbolt™ mechanical multi-jackbolt tensioners—to permanently tension the joint—without losing tension on the joint.
- Rather than tensioning one bolt at a time, which can continually create movement of the load, the HCS immobilizes the entire joint.
- An internal seal is installed to reduce leakage at the 4-way joint area where the cylinders for the combustion and turbine sections meet. The seal functions to eliminate any leakage paths that cannot be corrected by realigning the cylinders.

Outage emergency response

Schock Manufacturing
Jeff Cozbey, project manager

Presentation is a collection of single-screen solutions, with photos and testimonials, for problems encountered by your user colleagues—including the following:

- Blow-out of the expansion joint on a 7EA.
- Failure of the distribution grid plate on a W501D5.
- Failure of the HRSG duct liner on a W501F.
- Failure of diverter-blade landing bars in a W501D5 stack.
- Removal of failed baffles in a 7FA exhaust stack.

ARNOLD Group. Permanent placement of redundant sets of heating wires on the casing below the split line, plus the use of a heat-reflecting

- Failure of diverter-damper blade liners on a 7EA.
- Replacement of silencer baffles and silencer duct floor.

Optimized insulation for M501 and W501 gas turbines

ARNOLD Group

Pierre Ansmann, global head of marketing

One of the users' favorites at industry meetings, Pierre Ansmann, presented on the significant heat-rate improvement owner/operators can expect by installing the company's single-layer insulation system.

He began by highlighting the problems and design issues with standard insulation. Next, Ansmann spoke to the design highlights of the company's single-layer system. It features interlocking high-performance blankets which conform perfectly to the turbine surface. High-quality materials and manufacturing, and long-term high-temperature resistance, allow the company to guarantee reuse of its insulation system for 15 outages without a decrease in efficiency.

An extensive technical comparison between standard insulation and Arnold's single-layer system was followed by a case study showing a 0.7% heat-rate improvement based on customer data. Comparisons of surface temperatures when using standard and Arnold insulation systems on various turbine models illustrate why more than 600 of the latter are installed worldwide.

Debottlenecking non-duct-fired HRSGs after GT upgrades

HRST Inc

Bryan Craig, PE, director of engineering

Bryan Craig opens with bullet points on what owner/operators typically expect when upgrading their gas turbines—including these: increase power output by up to about 10%; reduce heat rate by up to about 1.5%; increase turbine exhaust-gas flow rate by up to 2% at baseload; and possibly increase exhaust-gas temperature by up to 50 deg F.

Key areas of concern in the attempt to achieve such goals include the following:

- Will the new steam flow exceed the HRSG's rated capacity?
- Will an HRSG capacity rerate be required?
- What will be the impact on the safety-valve set point and the valve's relieving capacity?

HRSGs with duct burners can turn down burner heat input to regulate boiler performance, whereas non-duct-fired units may need to reduce load to prevent excessive steam flow or pressure. However, reducing output rarely is a viable option.

The presentation focuses on approaches for debottlenecking non-duct-fired HRSGs on F-class units that have undergone gas-turbine upgrades. Included is an overview of HRST's FlexTune® steam suppression and economizer bypass for controlling system operating pressure. Stated benefits: It allows the GT to return to its maximum load, allowing non-duct-fired combined cycles to use the full potential of their turbine upgrades for operational flexibility, maximizing plant output, and preventing the boiler from exceeding its capacity. Examples discussed to help plant and asset management understand how to optimize plant operation while remaining in Code compliance.

Oil: Your hidden asset

C C Jensen Inc, Oil Maintenance
Eddie Rowland, power and industry sales manager

The main point of the presentation: Treat oil as an asset, not a consumable. Maintain it from the time the asset is installed and dispose of it only after the oil has reached end of life. This requires monitoring the lubricant's condition regularly and keeping it clean via both in-line and offline filtration.

Guidelines and tests that can help you maximize your fluid's life include the following:

- Viscosity.
- Total acid number.
- Additive depletion.
- Particle count.
- FTIR spectroscopy (ASTM E2412).
- MPC membrane test (ASTM D7843).
- Ultra-centrifuge test.
- Water/moisture content (ASTM D6304).
- Foam test (ASTM D891).
- Demulsibility (ASTM D1401).
- RULER Test (ASTM D6971 and D4378).
- RPVOT Test (ASTM D2272).

Improvements/changes in torque converter operation

Voith US
Bob Wasik, manager of retrofits and upgrades

Primary message delivered by Bob Wasik, for years Voith's primary customer contact in the US, had to do with improvements recently made by the company in the area of customer support. Examples: Reorganization and expansion of the inside service sales team; aftermarket sales staff back to full strength, and expanding; and reorganization of Voith's service management processes. Regarding hardware upgrades, the company's new guide-vane adjustment system (so-called VEHS actuator) is said to improve operational flexibility during turbine startup.

Frenzelit. Installing an upgraded expansion joint

Expansion joint upgrades for legacy 501FD and 5000F units

Frenzelit Inc
Harald Reichel, president, and
Joe McFadden, account manager

If your expansion joint is suffering a soft-goods or manifold failure, this presentation is worth reviewing for its many photos of damage and repairs. Benefits of Frenzelit's expansion-joint upgrade are said to include the following:

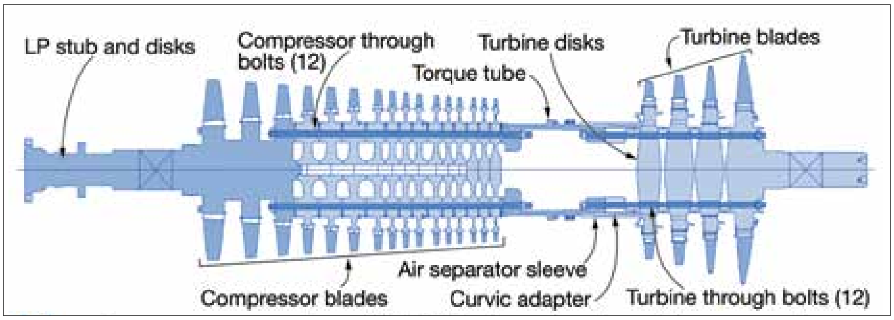
- Expansion-joint soft goods. Upgraded soft goods guard against internal moisture and pulsing during startup.
- Hard parts. Upgraded frame design helps protect against thermal cycling.
- External manifold insulation. Spring-loaded bands assure insulation will remain tightly wrapped around the manifold during thermal transients. Also, they mitigate sagging that would allow radiant heat to blow onto the bottom section of the expansion joint.

Rotor concerns and advanced repairs

Sulzer Turbine Services
Jim Neurohr, gas turbine product manager

Describes the company's robust, repeatable repairs and solutions to the following issues tracked over the years by technical personnel at the company's rotor repair facility:

- Broken alignment fits of the forward stub shaft.
- Compressor through-bolt failures.



Sulzer. Rotor arrangement for a W501FD2 shows locations of problem areas noted in the company's presentation discussing its repeatable repairs and solutions

- Fretted air baffles.
- Significantly worn disc seal arms.
- Advanced laser metal deposition repairs.

Air filtration and extreme weather

Donaldson Company
Bob Reinhardt, GTS

Speaker highlighted the steps owner/operators can take to keep their gas turbines running at peak performance and efficiency even when encountering difficult environmental challenges—such as wildfires, salt-laden air in coastal locations, industrial chemicals, hydrocarbons from vehicle exhaust, and cottonwood. Reinhardt shares the company's expertise on how to optimize fuel consumption, extend filter service life, differentiate between F9 and HEPA, and how reliable maintenance can extend turbine life and lower the cost of ownership.

Powerplant recovery

Shermco Industries
Todd Baker, director, national accounts

Company's response to the catastrophic failure and complete loss of a 650-MW steam turbine/generator offers valuable lessons learned. Among them: Slow is fast.

Project began with the following work breakdown:

- Discovery. What was damaged, accurate documentation available?
- Recommendations. Repair or replace, re-engineering required?
- Organized demolition. Nothing gets removed without documentation.
- Installation. Scrutinize everything, examine carefully for issues.
- Commissioning. Test every device and every function.

Among the lessons learned:

- Have a good project schedule. Identify the critical path, set dependencies.
- Onsite engineering. Goals: quick identification and resolution of new issues.
- Establish clear lines of decision-making. Avoid making decisions by committee when possible.
- Plan, adapt, plan.

Developing an effective safety plan required a major effort—involving modifying lockout plans, addressing air hazards, developing new policies and procedures to fit the work plan, etc.

Case studies on gas-turbine intake and exhaust system optimization: Improving safety, reliability, and performance

SVI Industrial (SVI Dynamics/Bremco)
Tucker York, director of acoustical engineering

There were these three major components to Tucker York's presentation:

- Ways to improve gas-turbine operating efficiencies through gas-path refinement, including:
  - Optimizing intake- and exhaust-system aerodynamics.
  - Intake- and exhaust-silencer refinement.
  - Reduction of static and total pressure loss.
- Demonstrate reliable ways to upgrade simple-cycle turbine intakes and exhausts, including: one-dimensional algorithms, CFD, BEM (boundary element method), SoundPlan, and test methods.
- Methods to reduce powerplant noise emissions.

One of the case histories reflected the experience of a peaker plant with three W501D5A engines commissioned nearly 30 years ago which suffered icing issues during fog. Challenge was to improve availability and aerodynamics. A dozen well-illustrated slides with CFD images walks you through the challenges identified and how the problem was solved.

Another case history, this one involving a W501FD2 simple-cycle unit, showed how problematic exhaust-system noise was mitigated by modifying the bar silencer array and turning vanes.

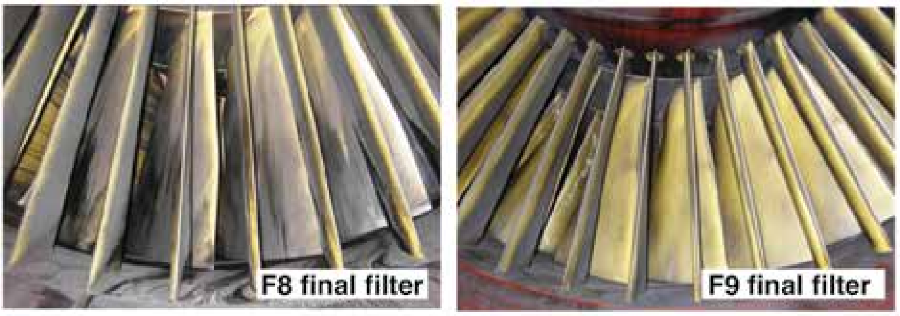
AGT Services' Jamie Clark brought 501F and 501G users up to date on fleetwide problems and what's required to restore their generators to near-new condition. Photos galore.

Common generator issues and contingency planning

AGT Services Inc
Jamie Clark, sales manager

As generators age, old issues rearise and new issues are identified. Jamie Clark uses excellent photographs to illustrate problems identified both during online testing and monitoring (partial discharge, endwinding vibration, electromagnetic impulse, and flux probe), and during an outage. Topics covered range from inspecting and remedying deficient high-voltage bolted connections, to issues such as field turn-to-turn shorts, brushless exciter problems, and stator/field grounds.

SVI/Bremco's presentation demonstrates reliable ways to upgrade simple-cycle-turbine intake and exhaust systems using one-dimensional algorithms, CFD, and other methods



EMW filtertechnik GmbH. The positive impact filtration has on compressor cleanliness is visually evident here. Each photo shows deposits on blades in the same compressor after 5000 hr of operation

Clark offered the following guidance:

- Get your generator's baseline condition at the earliest opportunity. Fix problems identified correctly the first time, even if it means taking a major to do the work. Thereafter, consider minor inspections in lieu of field removal
- Be aware that significant increases in cycling duty warrant shorter outage intervals. While baseload or seldom-run machines may enjoy longer intervals, don't forget the impact of time on turning gear.
- Use online monitoring to identify issues before the outage. Keep in mind that many units are close to or over their 25-30-year winding design lives.
- Beware resource constraints: Get your contractors and spare parts locked in before you might have in past years.

Better filtration pays for itself

EMW filtertechnik GmbH
Florian Winkler, marketing manager

The compelling economic and operational advantages offered by high-efficiency filtration support the upfront expenditure on superior filters, Florian Winkler told conference attendees. Among his talking points:

- Improved filtration minimizes the degradation of gas-turbine components and is conducive to maximizing power production and the possibility of receiving capacity bonuses.
- Efficient filters contribute to higher combustion efficiency, thereby saving fuel, reducing emissions, and potentially reducing heat rate.
- The number of compressor water washes required is reduced, increasing unit availability.

Turbine lifecycle management: Developing a tactical plan to mitigate varnish

Shell Lubricant Solutions
Chris Knapp, product application specialist

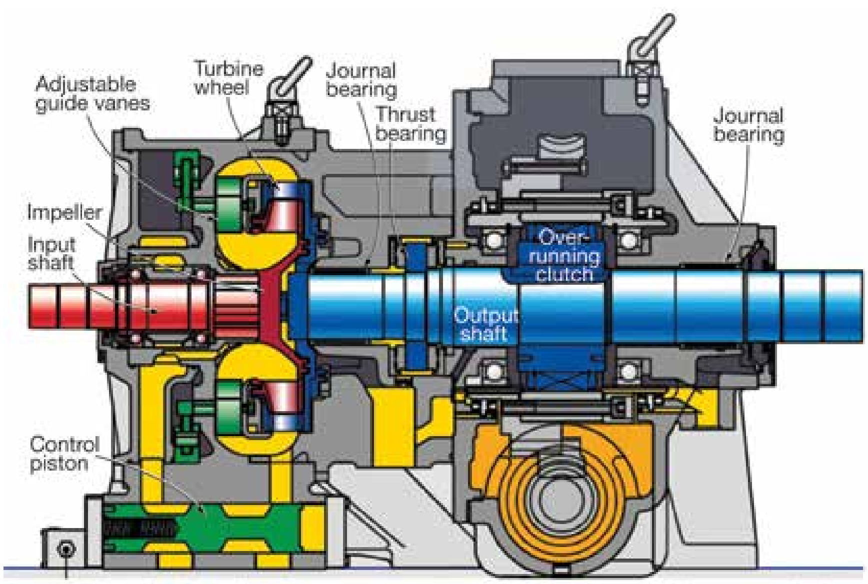
Varnish formation typically is of greatest concern in the managing of lubricant health in gas-turbine systems. Reasons: The presence of varnish negatively impacts turbine performance, reduces lubricant life, and is costly to eliminate once it has formed. Many users experiencing varnish-related issues look to higher-performing lubricants, expensive filtration systems, varnish mitigation additives, and/or system flushing. However, when improperly applied, these potential solutions may not provide the intended result.

Preventing varnish formation is the best way to avoid its negative performance consequences. Achieving a varnish-free system throughout the fluid lifecycle requires knowledgeable design, lubricant selection, filtration, fluid analysis, and end-of-life fluid change strategy.

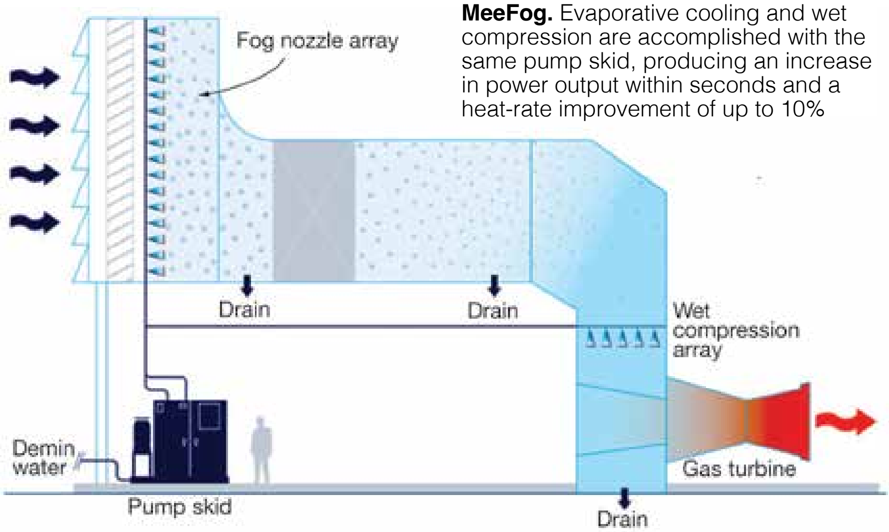
Torque converters in starting packages: Long-term wear and failure modes

Powerflow Engineering Inc
John Baciak, processing engineer

Torque converters, used to multiply torque during startup procedures, can have integrated gears and clutches to turn the shaft during engine cooldown. The good diagrams and photos provided help the reader navigate the slide deck to better understand what to look for during inspections. Prob-



PowerFlow Engineering's torque converters are used to multiply torque during gas-turbine startup. They may have integrated gears and clutches to turn the shaft during engine cooldown



MeeFog. Evaporative cooling and wet compression are accomplished with the same pump skid, producing an increase in power output within seconds and a heat-rate improvement of up to 10%

lems covered include the following: leaks caused by wear of gaskets and seals, bearing failures, effects of long-term storage, corrosion, clutch failures, labyrinth ring wear, piston wear, cavitation, etc.

MeeFog systems for gas-turbine cooling and wet compression

Mee Industries Inc
Derek Grayson, sales director, and Thomas Mee, CEO

MeeFog may be home to the electric power industry's foremost experts on fogging/wet compression, having decades of analytical and plant-level experience on the technology. Derek Grayson encouraged attendees to consider this cost-effective method of power augmentation for delivering additional megawatts virtually instantly in time of need.

Fogging/wet compression systems are easy to integrate with gas-turbine controls, he said, adding that his company typically can deliver the necessary equipment in three months or less and can connect the new system to existing equipment within a favorable outage window.

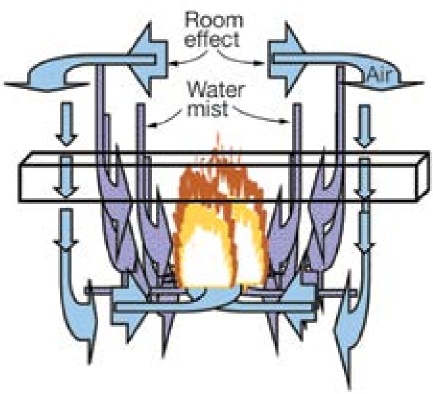
Erosion risk is reduced with small droplet size—a distinguishing characteristic of MeeFog's systems. Droplet size and its impact on equipment received significant air time.

The end of low-pressure CO2: How to protect your turbines and facilities going forward

Marioff NA
Jeff Krieger, sales manager

Most everything you need to know about high-pressure water mist systems as an alternative to low-pressure water mist, Halon, CO2, dry chemical, and other options. Focus of the presentation is on the benefits of replacing low-pressure CO2 systems with high-pressure water mist. Plus, what to consider when planning and staging the replacement for your plant.

The cited advantages of water mist include



Marioff. High water-droplet momentum is key factor in fire suppression

the following:

- People safe. There is no need for a delay in activation—for example, to clear the confined space of personnel. Thus, the system can remain active during maintenance.
- Environment safe. There is no risk of use restrictions or ban.
- Performance is not compromised by an open door to the enclosure. Therefore, there is no need to perform enclosure integrity tests—for example, a door fan test.
- Minimal damage with optimal use of water. Water mist prevents reignition by cooling the environment below the flash point.

Cold-weather case studies (2020-2022)

Tetra Engineering Group Inc
Dave Moelling, PE, chief engineer

With winter only a few weeks away in many areas, Dave Moelling offers timely guidance regarding actions and engineered improvements to consider for improving the cold-weather readiness of your plant. The presentation encouraged discussion on the recent NERC Reliability Guideline for Generating Unit Winter Readiness (EOP-12); implications for future cold-weather planning are included.

What follows are a few bullet points extracted from the 35 slides comprising this presentation to provide a flavor of the valuable information offered. If freeze protection is a concern, you'll want to access the entire slide deck.

- Normal heat trace and insulation are not always sufficient for high-wind conditions.
- Key instruments should have sensing lines with enhanced freeze protection.
- Enclosures of key areas are a must—including doghouses for drums, wind barriers for areas under HRSGs, space heaters for HRSG gas side and enclosed areas, and protection for drains and connecting piping.
- Modify operation during cold-weather events to minimize freeze risk. Examples: Periodically, run flow through stagnant pipes (spray water, drains, etc); install temporary heaters in shut-down systems.
- Heat trace piping typically 3 to 6 W/ft (IEEE 515).
- Valves typically require from 4 to 6 ft of trace for small spray water and other piping.

Breathing new life into old combined-cycle powerplants

EagleBurgmann Industries LP
Lauren Folsom, regional sales manager

Topics included in this presentation:

- FLIR thermal inspection.
- Material upgrades for turbine exhaust expansion joints.
- Exhaust manifold crack repair.
- Liner repairs.
- Air-house refurbishment.

Sulzer's standard process for checking fuel nozzles during overhauls includes visual and dimensional checks, flow testing, cleaning, and dye-pen, x-ray, and borescope inspections

501F fuel-nozzle fleet concerns (inspection and repair)

Sulzer Turbo Services Houston Inc
Jim Neurohr, gas-turbine product manager

While the 501F fleet matures and accrues operating hours, fuel-nozzle issues continue to challenge users. Sulzer has worked with numerous owner/operators to develop faster and more advanced fuel-nozzle inspections and repairs, thereby minimizing downtime when an issue arises—all while maintaining fuel nozzles in spec and reliable during operation.

Jim Neurohr's speaking points include the following:

- Internal bellows blowouts—what and how to look for the problem and address it.
- Support housing clocking.
- Avoiding issues causing burnout on support-housing rockets, fuel tips, and baskets.
- Accurate and repeatable flow testing—incoming and final.
- Optimizing flow and spreads.
- Breakdown of repairs made to components and their return to service.

Chasing zero: Toward a future of lithium-ion battery fires prevention (a/k/a Lithium-ion battery technology)

ORR Protection Systems Inc
Chuck Hatfield, business development manager

Come up to speed on lithium-ion battery technology by reading through Chuck Hatfield's slides. The term "lithium-ion" can be misleading to some because it differs depending on the user segment served. For example, the lithium-ion technology typically used for phones, computers, and electronics is lithium cobalt oxide (LiCoO2); that for electric vehicles (except Tesla) is lithium nickel manganese cobalt oxide (LiNiMnCoO2); for Teslas and home power walls, lithium nickel cobalt aluminum oxide (LiNiCoAlO2 a/k/a NCA); for batteries used in the electric-power sector, lithium iron phosphate (LiFePO4 a/k/a LFP.

ORR Protection Systems provided 501F and 501G users a useful primer on lithium-ion battery technology

Deployments generally are one of the following:

- Large containerized storage units.
- Small containerized storage units.
- New UPSs (uninterruptible power systems).
- Upgrades to existing UPSs.

Hatfield provides links to the major lithium-ion events (AES Chandler, Ariz, fire; AES BESS explosion; and Morris, Ill, fire) so you can get the details on what has occurred. He then reviewed why these events occurred—specifically:

- Overcharging creates a chemical reaction between the electrolyte and electrode which changes the electrolyte to gas.
- Overheating heats up the electrolyte/chemicals inside, causing a change of state from liquid to gas.
- Exothermic reaction begins, causing the separator to degrade.
- A short circuit results when the separator is breached.
- A thermal runaway occurs—most often when the rate of internal heat generation exceeds the rate at which the heat can be expelled.

Finally, about 20 slides provide guidelines on codes, tests, detection, fire barriers, fire suppression, water supply, annunciation, etc, developed by the National Fire Protection Assn, International Fire Code, and New York Fire Protection that you should be aware of. CCJ

DETECT FAULTS EARLY

ESA

Electrical Signature Analysis

ELECTRICAL SIGNATURE ANALYSIS IS A CONDITION MONITORING TECHNIQUE THAT UTILIZES A MOTOR'S UNIQUE ONLINE VOLTAGE AND CURRENT SIGNATURES TO DETECT FAULTS. ESA ANALYSES ELECTRICAL INDUCTION MOTORS, GENERATORS, POWER TRANSFORMERS, AND OTHER ELECTRIC EQUIPMENT.

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- Lower costs compared to third-party services
- Fewer forced outages from equipment failures
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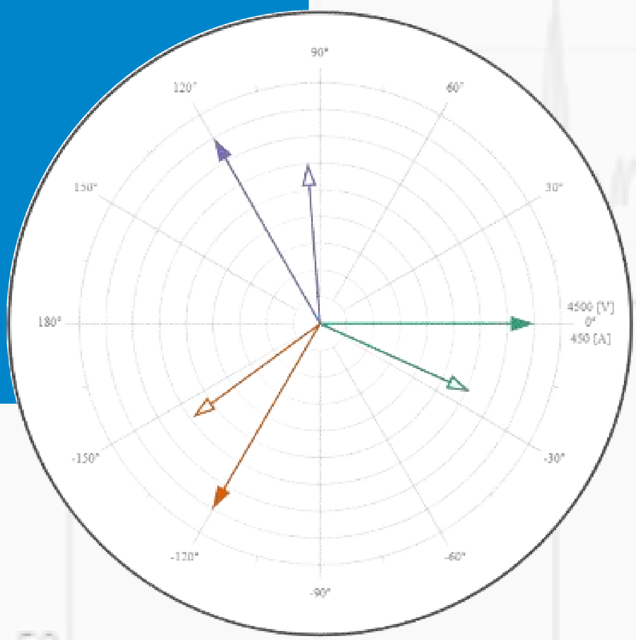
- Plants have remote access to data
- Integrates into InsightCM™ making analytics easier



MONITORS AND DETECTS FAULTS:

- Cracked/Broken Rotor Bar Damage
- Misalignment
- Eccentricity
- Bearing Faults
- Bearing Faults
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Attend the 2025 conference, Feb 9-14 • Tucson, Ariz
Loews Ventana Canyon Resort

The 501G Users Group only serves owner/operators of Siemens/Westinghouse engines. Users supporting G machines made by Mitsubishi Power are not members. This differs from the 501F Users Group (p 6), where owner/operators of all 501F engines share experiences.

The 501G is a small organization of well-connected engineers and technicians who have "grown up" together—so to speak—and generally quite familiar with each other's plants and equipment.

Background: The first Siemens/Westinghouse 501G, installed by Lakeland Electric, began commissioning operations in April 1999, but COD wasn't until March 2001—only a few days after the second machine began commercial operation at Millennium.

Fleet size is small by industry standards—24 engines at 13 sites in the US and one in Mexico. Four plants are equipped with one engine each; seven have two gas turbines; two are equipped with three machines each, arranged in 1 × 1 combined cycles.

User meetings typically host several first-timers, so many discussions are similar from year to year because newcomers have to be brought up to speed. But there's not much turnover in the top positions at G facilities which means each meeting pretty much picks up where the last one left off. This contributes to presentation efficiency, given the minimum amount of repetition.

G users came together with their 501F colleagues for Sunday social events (Feb 4, 2024) and the Monday technical program described in the 501F report referenced earlier—including the annual safety roundtable, vendor presentations (a/k/a Vendorama), reception, and vendor fair.

User presentations. A few of the user presentations made during the 501G portion of the conference are summarized below with the objective of providing enough information for you to decide if the content of a given slide deck should be reviewed in greater depth.

If that's the case, access the PowerPoints of interest at https://forum.501Gusers.org. But be aware that you must be a registered user to gain access. If not, you can begin the registration process with a simple mouse click. CCJ readers who already are registered will find the presentations in the folder "2024 Conference Materials." (Click on the magnifying-glass symbol at the top right-hand side of the page.)

Seal-oil modification

In spring 2022, Unit 3 at this plant, equipped with three 1 × 1 combined cycles powered by 501G gas turbines, tripped offline because of high relative vibration at the turbine end of its gas-turbine/generator. The OEM's diagnostic center noted fluctuations in the pressure and temperature of the air-side seal oil. Its suggestion was to restart with intensive monitoring of the vibrations and seal-oil parameters.

During this activity, a technician noted that during startup the local analog gage, located downstream of the thermocouple, was reading almost 10-deg-F lower than the t/c providing data to the DCS.

Further investigation into historical data, and trending when the generator had excessive vibrations, revealed that typically there was a large variation in the air-side seal-oil temperature at the turbine and collector ends of the machine.

The plant team developed a plan to remove the local analog gage and install a t/c in its place. There were open terminals in a nearby I/O cabinet, and the well where the t/c was installed, was a dry well, making the swap quick and easy. The new t/c senses oil temperature about 14 ft further downstream from where the existing t/c was installed.

The plant and OEM agreed with the install and logic changes to have the cooler bypass valve controlled by the new t/c. Finally, the plant techs decided to use the old t/c in the new logic as a fail-safe in case the new t/c faulted.

Good news: The seal-oil mod eliminated the vibration and there have been no issues associated with seal-oil temperature regulation since the project was completed. To dig into the details, scan the nearby QR code with your smartphone or tablet.

501G Steering Committee

Chairman

Jody Lumpkin, *plant manager, Hillabee Generating Station, Constellation Energy Corp*

Members:

Scott Wiley, *outage manager, Vistra Corp*

John Wolff, *technical support/compliance manager, Ironwood, EthosEnergy Group*

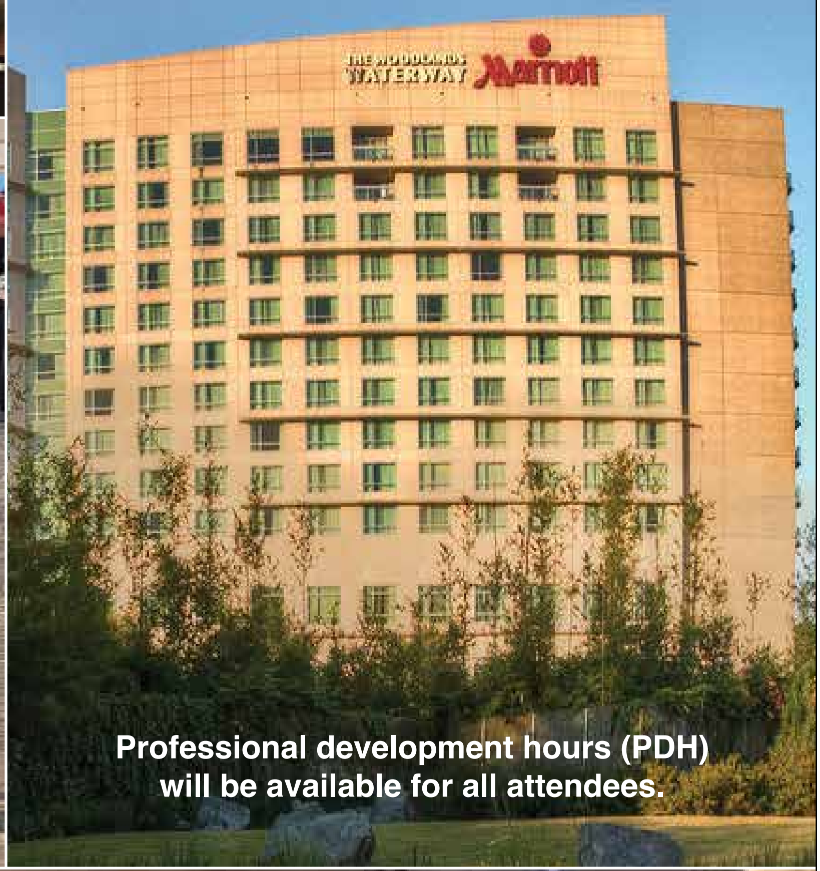
Kevin Robinson, *operations manager, Lakeland Electric*

Condenser event: January 2022

This case study of a condenser event may well be one of the most valuable safety briefs you've ever received if your combined cycle is equipped with a fuel gas heater (FGH). An abridged account of the incident follows. It was discussed at the previous 501G meeting, but the safety-conscious steering committee wanted to be sure personnel fleetwide are aware of the incident.

As a result of the failure of a main lead in the steam turbine/generator, the facility was in a steam-turbine outage in January 2022 during which the GTs remained "available" to the grid (with fuel at pressure up


What is a turbine bypass system?


THE WOODLANDS WATERWAY Marriott

to the FGH stop valves). With the plant experiencing numerous issues with the FGH (for example, leaking gas isolation valves) and its leak-detection system (prone to false alarms), and other factors, natural gas found its way to the condenser via the IP water-side supply line (the source of heat for the FGH).

The plant was down for 10 days, but with cold weather in the forecast, the gas turbines were started to build up pressure to about 50 psig in the HRSG to prevent freezing. The steam pressure in the HRSG provided the motive force to move the gas that had been accumulating in the IP drum to flow down the steam piping to the condenser.

When a welder arrived to repair a 1-in. pipe connection on the outside of the condenser, the arc ignited the gas and the subsequent explosion blew out six rupture discs on top of the unit, caused bolting threads on the LP steam-turbine cover to fail, and damaged internal structural supports. Rupture-disc parts were found all over the plant site. The explosion was heard and felt throughout the plant.

No one was injured (not even the welder), no condenser tube leaks occurred, and the LP section of the turbine suffered no internal damage.

Recommendations to avoid a similar incident elsewhere, included the following:

- Eddy current test FGH tube bundles and perform leak testing at least every six years.
- Use more robust (expandable) inserts when plugging tubes.
- Ease plant staff access to vent valving and instrumentation.
- Develop preventive-maintenance guidelines for FGH systems.
- Perform comprehensive FGH system design review.
- Install permanent redundant methane detectors on air ejectors with feedback to control system.

Reheat-header replacement

Presentation covers ever so briefly the replacement of lower reheat headers on the plant's two heat-recovery steam generators. Project was completed successfully in eight days according to the personnel involved; they credit Viking Vessel Services' Tuff Tube Transition (TTT), a part qualified to Section I of the ASME Boiler and Pressure Vessel Code, for the success achieved.

According to Viking, TTT reduces thermal expansion for a stronger, more secure tube-to-tube and tube-to-header connection than a conventional open-root butt weld, as well as the purge requirements associated with it. The connection reportedly can be made in a fraction of the time required for a conventional weld.

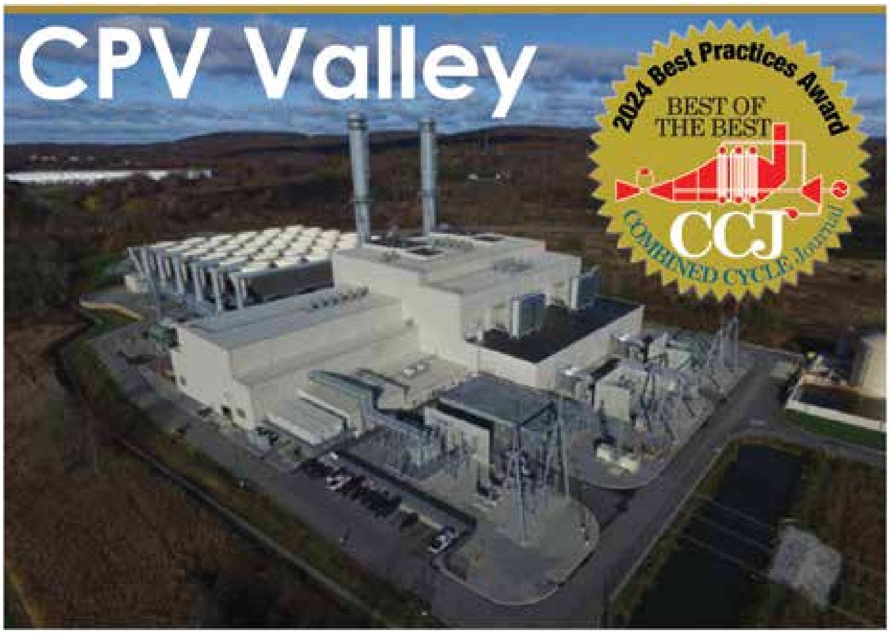
Row-4 blade: Lessons learned

A quick look through these slides might encourage you to attend the next meeting to see how the R4 blade saga discussed concluded—if it indeed is over. The case history begins with the OEM capturing six images of R4 blades in spring 2023, reporting no issues. Shortly thereafter new borescope requirements were announced by Siemens and R4 was reinspected at the OEM's request that fall.

Photographs distinguished between normal wear and unanticipated wear into the base metal. Based on this "evidence" the OEM recommended immediate replacement of the damaged R4 blades. But Siemens said it wouldn't have these parts until December and cleared the gas turbines for another 2000 hours (EBH) of operation. Note that both engines were scheduled for HGP inspections in fall 2024.

The plan was to replace R4 blades in Unit 2 in spring 2024 with the expectation of a 13-day turnaround. R4 in the sister Unit 1 was to be reinspected in spring 2024 with the intention of replacing damaged components that fall. However, the OEM then advised it did not have the labor to support the replacement of Unit 1's R4 blades if they had to be replaced.

Register for 2025 conference at your earliest convenience to share information with fellow 501G users. CCJ



CPV Valley Energy Center

Owned by CPV/Diamond Generating Corp

Managed by Competitive Power Ventures

Operated by DGC Operations LLC

680 MW, gas-fired 2 × 1 SGT6-5000-powered combined cycle, located in Middletown, NY

Plant manager: Michael Baier

Anti-icing system prevents snow-related derates, outages

Challenge. Since commissioning, during winter weather events, the gas turbines would have to derate and/or take a forced outage because of snow clogging the compressor-inlet prefilters (Fig 1). The problem persisted with an upgraded filter design, replacing the flat, box-style filters with a reverse pocket design. Through experience, the site developed a winter-storm protocol to derate the plant when the inlet-filter differential pressure (DP) started to rise. A combination of plant staff and contractor personnel were made available to physically remove the snow from the filters during weather events. Even with the proactive measures in place, at least one of the GTs generally would be forced offline.

Solution. Valley Energy Center and Competitive Power Ventures personnel worked with PSM to engineer and implement an anti-icing system that would tee off the existing compressor inlet-bleed-heat (IBH) system. The system tees into the IBH piping upstream of the OEM's block valve inside the gas-turbine package (Fig 2). The anti-icing system, when in service, directs air from the GT's compressor to the front of its inlet prefilters via an array of patented stainless-steel nozzles.

The nozzles include silencing media and perforations to disperse the air, thereby creating a curtain of hot air that melts most of the snow ahead of the prefilters. The nozzles are threaded to stainless-steel piping inside carbon-steel modules bolted to the face of the existing inlet structure (Fig 3).

Structural steel was added to support addition of the modules. In total, five 9 × 45-ft modules were added to each inlet house (Fig 4). The modules were flown to the roof using a crane (Fig 5) and then bolted in place before removing the modules from the crane hook. The modules contained the stainless-steel piping that the nozzles were threaded into.

Some of the piping and valves were installed while the unit was online, the remainder concurrently with HGP inspections on both GTs. Before the outage, the first revision of the logic for the anti-icing systems was developed and installed. Because the facility also was undergoing a DCS upgrade during the HGP outage, PSM, CPV Valley, and the DCS OEM worked to add the logic to the DCS version that was going to be uploaded during the outage.

Additionally, during the outage, a PSM subcontractor installed all the instrumentation and ran all the control cables for the instrumentation and valves to the I/O cabinets (Fig 6). CPV Valley personnel made the final connections in the I/O cabinet. After all connections were made, loop checks were performed to verify all the wires were landed to the correct points.

Upon mechanical completion of the anti-icing systems (Fig 7), one gas turbine was brought to full speed/no load to check for leaks from all pipe flanges. After a satisfactory leak check, all the flanges were insulated. Several weeks after returning to service, PSM came back to run a functional test of the anti-icing systems on both GTs, tune the control valves, and set protective limits using temperature as a parameter.

For the test, a temporary thermocouple

1. Snow buildup on GT-inlet prefilters is at left, snow plugging the final filter at right

2. Anti-icing header is located below the filter house

3. Anti-icing module is ready for installation

array was installed in each GT's filter house to monitor the temperature at the inlet filters. After initial testing, other modifications were made to the logic for additional GT protection. For personnel safety, signage was added to the filter-house doors on both units warning not to enter without being on a LOTO; and the doors were padlocked shut as an additional measure.

Before the first use of the anti-icing systems, a draft operating procedure was created and reviewed with operations personnel so that they were familiar with the permissives required to place the system in service and what parameters to monitor while the system is operating. During the winter, as site personnel became familiar with how the system operated, several revisions were made to the procedure, and parameters were adjusted in the logic.

Results. Despite the 2023/2024 winter being mild in southern New York, the new anti-icing system was placed into service six times—all successful. Prior to first use, temporary cameras were staged and focused on the lowest section of the inlet prefilters on both units to allow remote monitoring of the filter condition.

For the first storm of the 2023/2024 winter, Jan 6-7, 2024, additional staff was brought to site as standby support. Plus, the plant engineer was onsite to assist if there were any issues with the logic that prevented the anti-icing systems from going into service.

The anti-icing system performed as expected during the first storm, with no operational issues other than the anticipated loss in megawatts. Based on trending and operator observations, the amount of snow clogging the inlet filters was minimal compared with previous storms of similar magnitude. No entry into the inlet house was necessary.

Comparing GT performance to a snow event on Feb 27-28, 2023 that caused one unit to shut down, the plant was able to operate with greater availability during the first 2024 storm because of the anti-icing systems. Review of the DCS historian data (Fig 8) captured during the 2023 storm revealed that inlet-filter DP had climbed to more than 2 in. H2O on both units while limiting plant output to a low of approximately 200 MW.

During the first event in 2024, with the anti-icing systems in service, the DPs for both GT's inlet filters stayed around 1.3 in. H2O (with the exception of a short spike to 1.8 in.

on one unit). Plant output stayed above 520 MW for the duration.

During the 2024 storm, duct firing was not permitted while operating the anti-icing system because HRST Inc was performing an analysis to determine if there was a risk of damaging HRSG components downstream of the firing duct. Result of that analysis: The site could operate the anti-icing system without limitation; however, at the time this entry was submitted for Best Practices judging, no tests had been performed because of warm ambient temperatures.

Project participants:

Michael Baier, plant manager
McKenzie Slauenwhite, plant engineer
Thomas Viertel, maintenance manager
Dave Engleman, operations manager
Bob Arraiz, lead IC&E technician
Daniel DeVito, IC&E technician

The road to reliable ultrafiltration

Challenge. An ultrafiltration (UF) system was installed during construction of CPV Valley's water treatment plant. However, it could not manage the purity of the city-supplied waste effluent, failing continually. MPW Industrial Services was asked to provide a UF trailer—a/k/a/ BOOM—to help supply plant-quality water during plant commissioning. It performed without issue.

Solution. MPW designed a 40-ft "container" for installation inside the water-treatment building to replace the existing in-house UF system. The container features two UF trains, each consisting of 30 modules, which treat the local POTW (Publicly-owned Treatment Works) water supplied to the plant. This system produces up to 300 gpm of filtered water. The processed water then is piped to CPV Valley Energy Center's in-house reverse-osmosis system.

Finding the appropriate water-filtration solution is often a challenging task for plants in the power, pulp and paper, and fossil-fuel industries. Faced with high upfront capital costs and the lack of support staff to maintain a comprehensive filtration system, in-

4. Snow hoods (left) were removed (right) to accommodate the anti-icing module

5. Anti-icing module is lowered by crane for installation in the filter house

6. Control valve and instrumentation underpin the anti-icing system

dustrial companies can lack solutions to fit their specific needs. MPW Industrial Services provided CPV Valley a fully managed system that delivered a dependable clean water supply to the plant. It is referred to internally as the BOOM (Build, Own, Operate, Maintain) water system.

MPW built the system at its fabrication facility in Ohio. Equipment was installed in DOT enclosures for weatherproofing. MPW personnel installed all interconnecting pipe, power, and controls onsite.

After installation was complete, MPW evaluated the system's operation. During the startup phase, it verified that effluent quality and quantity specifications were met. BOOM system PLC controls were integrated with the existing water-treatment-plant PLC logic that controls the POTW raw-water pumps supplying water to the plant. The BOOM system calls for a raw-water pump to start when the service-water tank level drops below a specified level.

Results. Currently, the system is running in normal operation. MPW assigned a field service technician (FST) to perform site visits for up to eight hours per week, to review the operator's log, adjust chemical dosages as required, and make any other mechanical adjustments when necessary—plus perform preventive maintenance. Additionally, FST provides remote monitoring services as needed to maintain the system.

The primary FST assigned to the site was made available for 24/7 additional emergency support while candidate FSTs were trained to provide services to the site for backup. Additionally, MPW provided staff training on the proper emergency operation of the system.

Remote monitoring has become one of the most important innovations over the past decade. It has decreased the need for onsite support staff, leading to improved plant safety, and contributing to reduced downtime, which usually promotes higher efficiency.

Pump motors in the BOOM system are automatically controlled by an electrically efficient variable-frequency drive. By using VFD controls, plant operators can manipulate the pump and impeller speed at a varied rate, allowing the motor output to match the system requirement for improved pump performance. This technology, as well as all the other technology used in the BOOM process, is compatible with a variety of other mobile industrial water systems, simplifying integration.

Project participants:
Dave Engelman, operations manager
Tommy Viertel, lead mechanical technician
Josh Zimmer, plant engineer

7. Anti-icing modules installed

Experience upgrading Siemens' T3000 V9.2

Challenge. Using supported, patched, and up-to-date software is a good cybersecurity practice. Using obsolete versions of software means that the patches and updates to the software will no longer be developed, and supported, which puts users at an increased risk of cyber threats such as ransomware. CPV Valley had an early version of Omnivise T3000 DCS and was approaching the extended end date for the Windows servers. Once the extended end date passed, there would be minimal support that could be provided for the DCS, ultimately decreasing the effectiveness against cyberattacks.

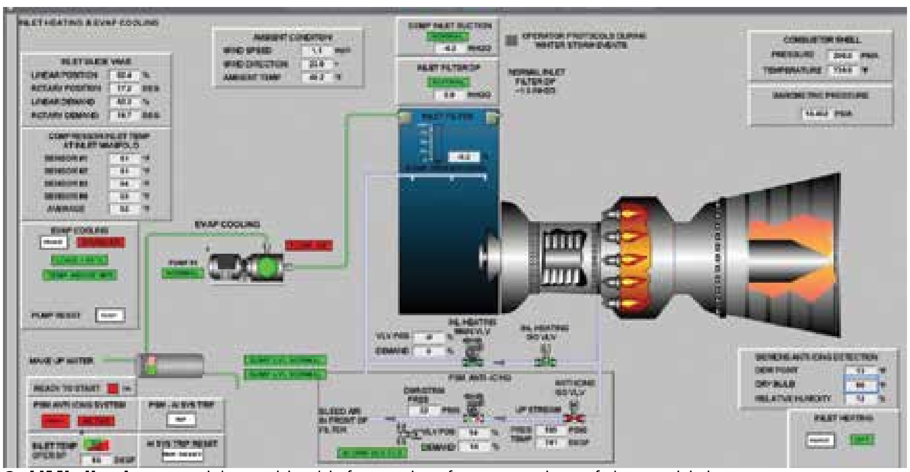
Solution. To ensure that the CPV Valley Energy Center could operate in the future using a DCS that was fully supported with patching available, DGC Operations, CPV, and Siemens Energy worked collaboratively to upgrade the DCS to the latest version of T3000. The plan initially was to upgrade to T3000 V8.2; however, with the T3000 V9.2 finishing up development for US implementation, the decision was made to upgrade to V9.2 to provide for a longer window before obsolescence.

To be sure there was an adequate outage opportunity to complete the upgrade implementation with work scheduled during concurrent hot-gas-path (HGP) inspections on both gas turbines in fall 2023. Monthly meetings were started in summer 2022 to discuss the implementation schedule, status of the project, hardware lead times, support/recommended actions that should be completed by the plant before the work began and any other items related to the project. DCS consultant Selva LLC, was brought in (spring 2023) as a third party to support the upgrade.

Several tasks completed prior to the upgrade proved beneficial. Specifically, a backup was taken of all the logic in a JAR file and screenshots of all the plant displays were captured and organized. The process of capturing screen shots and organizing them started about a month prior to the upgrade and involved plant operators, plant management, and Selva.

Plant operators took additional screenshots of plant displays that contained equipment or processes with manual set points. This was advised because when the new DCS version was installed, the manual set points would not be carried through from the old version.

Other tasks completed prior to upgrade were a review of new cabinet drawings, inventory of items shipped to site, and attendance at the factory acceptance testing (FAT) to witness the performance of new software and hardware capabilities. CPV Valley sent the plant engineer, an IC&E technician, and a lead shift operator, and Selva, to the FAT at Siemens Energy's facility in Georgia. Server fail-over tests were per-



8. HMI display provides critical information for operation of the anti-icing system

formed, as well as UPS and scalance communication tests. Plus, the functionality of Version 9.2 was confirmed.

After the FAT was completed, all the hardware was packaged up and sent to the site. The upgrade took place during concurrent HGP inspections of both GTs. Since the upgrade process would render the DCS unusable for a couple of days, the upgrade was scheduled for the second week of the outage when all turbines would be off turning gear. Upon arriving onsite, Siemens Energy personnel worked with Selva to record all equipment timer information and take one last backup prior to upgrading the T3K.

Once the upgrade team received permission to proceed, the old hardware was decommissioned and the team went about installing/wiring up the updated hardware—including servers, communication modules, thin clients, scalances, and GPS antennas. After installation, Siemens Energy worked with the consultant to install licensing and perform loop checks of the new equipment. Upon completion of the system tests and manual set points being reset, consultant and Siemens Energy personnel departed the site—save one engineer. That person remained onsite until after the plant started up from the HGP outage. Several months after completion of the upgrade, the site coordinated with Siemens Energy to have a T3000 expert to come to the site for two weeks to train all O&M personnel on V9.2.

Results. The upgrade was completed successfully and on schedule because of the advance planning by all parties involved. One of the main reasons for project success was efficient communication throughout the entire planning process. While the site had the same lead on the project from start to completion, there were several project-manager changes on the DCS upgrade team.

Detailed meeting minutes and notes with action items ensured there was continuity among project managers and no time was lost as a result. Siemens Energy worked with the site team to develop a clear division of responsibility for all parties involved, accounting for all tasks and allowing for accountability and tracking throughout the project.

The screen shots taken of the plant display and the recording of the manual set points proved invaluable while getting the plant ready for startup. Even though most of the set points were re-entered by the consultant there were a couple instances where an operator noticed a set point was incorrect or questioned it. Having the backup, the correct set point was entered or confirmed to be correct within minutes of the discovery, minimizing any potential delay in the start-up.

Hiring a third-party consultant was a big contributor to project success. Selva was very familiar with the site's DCS and had years of experience working with the T3000; plus, it had expertise in powerplant operations. Having that resource available, provided the site with outside guidance during the planning process and an oversight during the implementation process.

With all the other jobs included during an HGP that require facility management oversight, having a liaison between the engineers completing the upgrade, and management, kept work moving at the pace required to meet schedule. The consultant also attended every meeting possible and assisted in the pulling of backups and making sure the site had all the documentation needed to complete the upgrade.

Other critical functions of the consultant were to archive operating parameters—like tuning constants, operator set points, timer settings, and ensure the ability to migrate to the new controllers after power-up. This effort assured a smooth migration.

Another beneficial decision was to send site personnel to the FAT. In order to extract the most value out of the trip, CPV Valley sent personnel from three separate departments—each assigned with different tasks and responsibilities. This allowed for a thorough check of all the logic loaded onto the new servers to ensure plant displays were the same as the previous version. Running through the testing of the hardware also provided some staff with a level of familiarity with the system before it was even installed.

The FAT also allowed plant staff to meet the people performing the upgrade and talk in more detail about the scheduling and sequence of the upgrade tasks. Note that during the FAT, CPV Valley and Siemens Energy coordinated to allow a third party design an anti-icing system for the site to mobilize an engineer to test the new logic in V9.2.

Finally, keeping one engineer onsite after implementation of the upgrade was invaluable in terms of facilitating a timely startup. As expected with a control-system upgrade, there were a couple of faults with the processors and some networking alarms that came in. Having the Siemens Energy engineer onsite to immediately support the upgrade reduced the amount of time it took to resolve any issues without involving the OEM's remote engineering support group.

For CPV Valley's upgrade there was an instance where a physical wiring change had to be performed on one of the automation processors. Completion of the change only took minutes with personnel on hand who knew exactly where to land the wire and could make redlines to the cabinet drawing to send back to the T3000 V9.2 upgrade project manager.

Project participants:

Michael Baier, plant manager
McKenzie Slauenwhite, plant engineer
Thomas Viertel, maintenance manager
Dave Engleman, operations manager
Bob Arraiz, lead IC&E technician
Daniel DeVito, IC&E technician

9. MPW Industrial Services' BOOM system provides CPV Valley filtered water from a waste-liquid resource. It removes TSS, organics, iron, manganese, and other contaminants. BOOM came fully automated with continuous monitoring instrumentation to ensure optimal operation

The proven value of a steam-turbine shell warming system

Red Oak Power
Owned by TigerGenCo
Operated by NAES Corp
776 MW, gas-fired 3 × 1 combined cycle equipped with Siemens 501FD engines, Foster Wheeler HRSGs, and a Toshiba triple-pressure reheat steam turbine
Plant manager: Dave Carroll

Editor's note: *Before reading this Best Practice, consider perusing CCJ's backgrounder on Arnold Group's steam-turbine warming and advanced insulation system, available by scanning the nearby QR code with your smartphone or tablet.*

Challenge. Steam-turbine cold-metal temperatures after lengthy shutdowns required between six and 10 hours of startup time to comply with STG warming curves. During the startup period, gas-turbine loads were restricted to prevent rotor-long conditions in the steamer. This increased the consumption of natural gas and consumables and produced higher emissions.

Solution. Red Oak personnel worked closely with Arnold Group, a subcontractor to Toshiba America Energy Systems Corp, to install Arnold's single-layer steam-turbine shell warming system during an HP/IP turbine major outage. Site I&E technicians worked with Arnold and Toshiba to integrate new startup curves and logic in the STG control system.

Red Oak was responsible for removing old insulation and pins before the casing was ice-blasted clean. Next, Arnold technicians installed the high-tech warming/insulation system on the main steam valve (Fig 1) and turbine (Fig 2). After post-outage testing of the STG, Red Oak and Arnold personnel commissioned the warming system, which maintained turbine metal temperatures at the optimal level for startup.

Results. First start after the extended shutdown was defined by a greatly reduced startup time compared to what had been customary after a shutdown of similar timeframe. The reduction in start time was 68.3%. The reduction in fuel consumption and in CO2 emissions over that period was 63%. Staff estimated that the savings in cooling-tower makeup and ammonia consumption at 68% and 81%, respectively.

There were more benefits attributed to the warming/insulation system but most difficult to quantify—including the following:

- Less wear and tear on startup bypass steam valves and attemperators.
- A uniform startup period allowing those bidding the plant into the energy market greater flexibility because they did not have to consult a chart to determine the startup time.
- Less gas consumption makes the plant more competitive when bidding to start on marginal days.
- Reduced stresses on the asset contribute to a longer productive lifetime, as evidenced by forecasts of unit operation out two decades or more.

Project participants:
Marc Hain, maintenance manager
Mike Brady, planner
Mike Malizia, I&E technician
Jason Pyzik, I&E technician

1. Planned layout of the valve warming system begins with the grid illustrated at the left. Installation of the heating coil (center) is next. Insulated valve is at right with step protection


LM2500 INSULATION SOLUTIONS AT ITS FINEST
ACOUSTIC
ACOUSTIC
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ARNOLD provides advanced Noise reduction Solutions for all kinds of LM2500 Packages
We Guarantee:
- Significant Noise Reduction
- Longer Product Lifetime
- OEM Approved Installation
ARNOLD provides advanced Single Layer Insulation for the Exhaust Duct of all LM2500 Frames
We Guarantee:
- Better Vibration Resistance
- Longer Product Lifetime
- higher Thermal Performance
- OEM Approved Installation
ARNOLD GROUP

2. Heating wires installed on the steam-turbine casing at the split line

How to develop a successful warming project

Arnold Group installed its first single-layer steam-turbine shell warming system on a GE D11 machine in 2017. Today there are two-dozen such systems in service worldwide—most in the US. Arnold's Norm Gagnon says early interest in this system was driven by regulatory and market requirements demanded of US power producers. But with many US rules and practices adopted by other countries, interest today is worldwide.

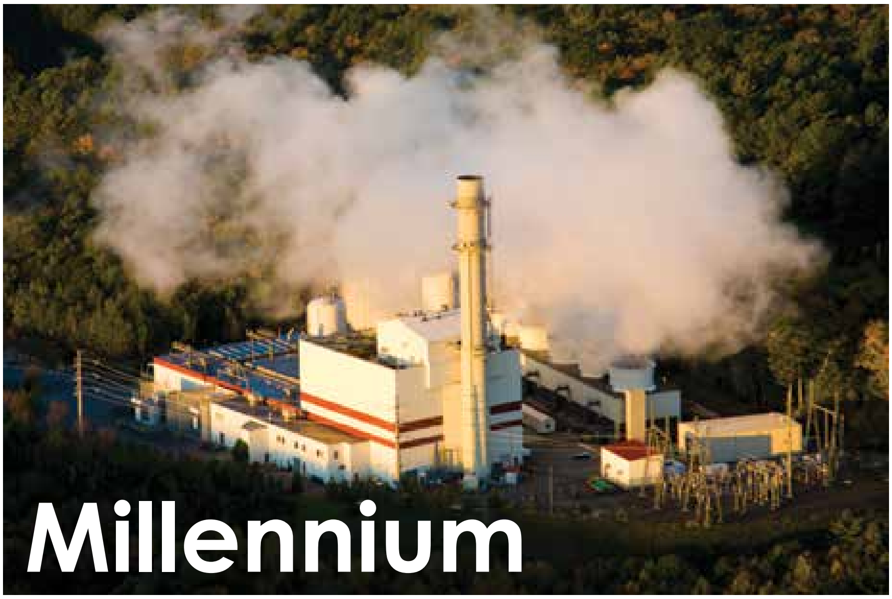
Many improvements in the original system, often focusing on software, were made during the technology's formative years to extend its capabilities—such as greater operational flexibility to profit from ancillary services and better control of upper/lower casing differential temperature and cooldown to shorten outages. Improvements are on-going with lessons learned factored into future projects.

Concerning heating-system capability, Gagnon says a rule of thumb is that for single-casing units, the turbine first stage typically is held at 750F, but a higher temperature often is possible. For double-casing units, the limit is about 450F.

Arnold credits its highly integrated relationships with turbine OEMs and plant owner/operators as critical to project success. The need for excellence in communications among the parties is at the top of Gagnon's list. Extensive pre-outage coordination and planning—including well-defined scopes of work and responsibilities—are required to assure activities don't creep outside the critical path. He cited coordination of laydown space in clearly labeled areas governed by a phased layout plan as very important.

Regarding schedule, Gagnon says turnarounds from purchase order to startup may be as short as six months—depending on shop availability and other project-specific conditions, equipment availability, etc. But 12 months is typical. With impeccable coordination and cooperation, warming systems can be installed in about 30 days, in lock-step with a major inspection. This given Arnold's extensive experience in the hand-crafting of heating coils, controls integration, and system commissioning.

Gagnon closed out the phone interview with CCJ editors while in China completing a successful installation, noting that the payback on a "shining-star" project achieved a payback of one year.



Millennium Generating Plant

Owned by Beal Bank
Operated by NAES Corp

360 MW, gas-fired 1 × 1 combined cycle equipped with the first Siemens 501G engine to begin commercial operation, located in Charlton, Mass

Plant manager: Max Greig

Solution for mitigating the effects of steam leaks in early W501G combustion systems

Background. The Millennium W501G is equipped with steam-cooled transition pieces which allow the gas turbine to run at higher combustion temperatures than possible without such cooling (Fig 1).

The spent coolant is returned to the reheat steam system, thereby improving plant efficiency. Note that the steam piping, located inside the GT enclosure, is flanged for ease of disassembly during outages.

Sixteen duplex thermocouples monitor average blade-path temperature (Fig 2). They also track the temperature differences among combustors, protecting the GT in the event of a high a temperature spread. Wiring for the t/cs runs in conduit and is terminated in junction boxes located next to the pipe flanges.

1. Steam piping is clearly visible on the transition pieces

Challenge. Millennium has experienced GT blade-path wiring issues arising from transition-piece (TP) steam-pipe flange leaks throughout its 23 years of commercial operation. While some instances of damage were minor, others led to forced outages. Replacement of all blade-path wiring became necessary, incurring both downtime and $80,000 in material and labor costs (Fig 3).

The latest incident involving t/c wiring was an August 2024 trip attributed to a blade-path temperature variance. Source of the problem: A leaking flange on the TP steam supply line. It put 530F IP steam in contact with the conduit that the blade-path wiring ran through. Steam got inside the junction box where the wiring was terminated, causing condensation to form on the terminal strips. A temporary fix involved replacing the flange gasket and running temporary wires outside the box away from the flange. That done, the GT could be started.

Solution. Plant staff collaborated to develop a permanent, long-term solution. First step was to relocate the junction box under the machine, keeping the conduit and wiring clear of the TP steam flanges (Fig 4).

2. Thermocouples monitor average blade-path temperature

Second: Experience led the team to focus on the leaking flange. Staff believed the most likely cause of the leak was a loss of load on the flange bolts. The team had prior success using Belleville-spring washers to resolve similar flange issues. The decision was made to install them on the TP steam flange to maintain the desired bolt load long term.

3. Leak in the transition-piece steam supply system damaged thermocouple wiring

Recall that there are several reasons a bolt might lose the load placed on it: They included thermal expansion, high-pressure cycling, gasket creep, and vibration.

4. Junction box was relocated to keep t/c wiring out of harm's way

Results. Modifications were completed during the 2023 fall outage and there has not been a recurrence of steam leaks since. The unit has cycled several times and the flanges have held without issue.

Project participants:
Max Greig, plant manager
Dennis Hamel, maintenance manager
Anthony Lucia, operations manager
William Wallin

Athens Generating Plant

Owned by Kelson Energy
Operated by NAES Corp

1080 MW, gas-fired facility equipped with three 501G-powered 1 × 1 combined cycles, located in Athens, NY

Plant manager: Steve Cole

Mod eliminates doubts regarding the accuracy of vibration readings

Challenge. New Athens Generating has had issues in the past with vibration readings on the steam turbine's (ST) MAD11 bearing. The seismic probes on MAD11 are under the turbine's cover, so the only way to access them is to do a complete cover lift and change out the probes, which is neither quick nor easy; not to mention downtime costs and cost of repair.

Solution. During a major overhaul of the Unit 3 E steamer (a/k/a Siemens/Westinghouse IP/LP turbine), Athens personnel investigated the location of the seismic probes and noticed bored holes next to the existing probes. Staff decided to tap the existing bored holes and order four new seismic probes—two to replace the run-time probes and two to install in the bored holes once they were tapped.

The plan was reflected in Management of Change (MOC) documentation and reviewed and approved accordingly. The MOC was to be implemented on ST1, which was next in line for a major overhaul.

The new probes were installed during the major overhaul on Unit 1 in accordance with the plan. The additional probes were wired to the Bently rack with the use of an additional 42M card, and the Bently was programmed to accept the new points. In the logic for the ST, the additional probes' feedback will only be used as a readout, and not in the trip schematic. The probes are used strictly as a backup in case a sensor fails; the logic remained that two seismic exceedances will cause a trip.

Results. By installing the new probes, Athens removed a single-point-of-failure concern and the risk of having to force points if a probe goes erratic from a faulty signal. Plan is to implement the same solution on Units 2 and 3 the next time there is a cover-lift/major-interval opportunity.

Project participants:
Athens I&C technicians
Plant management

SCR vaporizer rebuild improves system performance

Challenge. Athens staff was concerned about the accuracy of vaporizer outlet temperatures for the SCRs (selective catalytic reduction) serving the plant's three units. On startup, or during large load changes, vaporizer outlet temperature typically would drop considerably, possibly causing it to go so low that it would trip the ammonia block valve. That would require operator input, to manually reopen the valve and make necessary adjustments. Staff decided to inspect

Bored holes for seismic probes as found after cover lift (left), holes tapped and ready to install seismic probes (center), locations of the original probes and additional probe (right) the vaporizers and compare their readings to the original specs.

Solution. During the fall 2023 outages, plant personnel opened and inspected the vaporizers for all three units. The findings: Units 1 and 3 were up to OEM specs, but Unit 2 revealed a couple of concerns. For example, the level of the pall rings was at, or slightly below, the ammonia injection rings, and the outer ammonia injection ring was bent down, causing a central injection area.

Thus, the ammonia being injected was not being properly mixed with the gas-turbine exhaust because there was no "agitation" from the pall rings above the ammonia injection ring. Athens decided to rebuild the vaporizer on Unit 2 using OEM resources. On disassembly, technicians found that the expanded metal holding the pall rings off the bottom of the tank was badly deteriorated.

Results. The vaporizer was rebuilt with new pall rings, stainless-steel expanded metal, stainless-steel ammonia injection rings, and more supports under the injection rings to prevent the outer ring from being bent down again. During the first startup after the repairs were made, Athens monitored the vaporizer outlet temperature. It remained above the valve trip-point and showed considerable improvement in reactions to load. Additionally, Athens is planning to move the vaporizer outlet thermocouple down the pipe about 6 ft as recommended by the OEM.

Project participants:
Athens I&C technicians
Athens maintenance team
Management

PSM Asset Managers Conference

In Segment 3 of CCJ's three-part report on PSM's 16th annual meeting, users recount experiences with 501F, 7EA technology upgrades

This is the third and final segment of CCJ's report on PSM's 2024 Asset Management Conference, conducted at the Westin Beach Resort, in Fort Lauderdale, Fla, January 29-February 1. Segment One appeared in CCJ No. 78, pp 58-63, Segment Two in CCJ No. 79, pp 81-87.

Focus here is on the comprehensive suite of products and services, including PSM's well-known GTOP and FlameSheet™ brands, available for the 501F machine (Fig 1), a technology development effort begun a decade and a half ago, including two presentations on field experience from two of the largest gas- turbine/combined-cycle owner/operators in the country. A third user presentation reviews experience with a 7EA upgrade.

1. PSM's 501F portfolio ranges from improved component designs, technology upgrades for changing mission objectives, and long-term machine and/or fleet support. The following is a summary of products and services offered for that engine:

Compressor	Rotor	Combustor	Turbine	Exhaust system	Additional Services
All redesigned Model FD compressor components; S1-S3 standard and HSB versions; GTOP upgrade; W501FC and M501F support.	Two seed rotors for the 501FD1-3 with lifetime extension; destack/restack with lifetime extension; component replacement air separators, torque tubes, and compressor wheels; improved bolting and bellyband designs.	DLN design by PSM for the W501FC-FD3 and M501F3 engine models; component or system options; gas only and dual fuel; FlameSheet™ for all frames.	All parts for W501FC-FD3 (including those in Siemens' Value Generation Program); all major components for M501F3-F4; several components for 501F4-F5; improved static seal and inner support ring; ISSH (Interstage Seal Housing) rotable spare pool.	501FC-FD2 cylinder drop-in with new manifold front flange; 501FC-FD2 manifold drop-in with PSM's design and new option to interface with the advanced two-piece exhaust (TPEX); field service and tooling for the single-piece exhaust (SPEX).	AutoTune/ FlexSuite/ Flexramp packages; tailored GTOP upgrades with interval flexibility; complete support in line with large fleet of own long-term agreements.

From a high level, the various 501F GTOP versions offer output increases of between 8 and 20 MW and heat rate improvements from -2.5% to -3.8%.

Soon, GTOP (with FlameSheet™ Gen VII) will be achieving sub-30% turndown. Total number of 501F hot-gas-path (HGP)/compressor upgrades performed by PSM: 24.

If it is operating flexibility you are after, the company has options across the machine (Fig 2) including in addition to GTOP, the FlameSheet combustor, inlet bleed heat (IBH), exhaust bleed (ExB), wet compression, and digital logic. ExB, in particular, can achieve up to 10% better turndown, and can be coupled with separate or integrated anti-icing capability with no modifications to the filter housing.

Ultimate flexibility comes in the form of the FlameTOP 7 upgrade, a combination of GTOP and the FlameSheet™ combustor. The three general operating modes are the following:

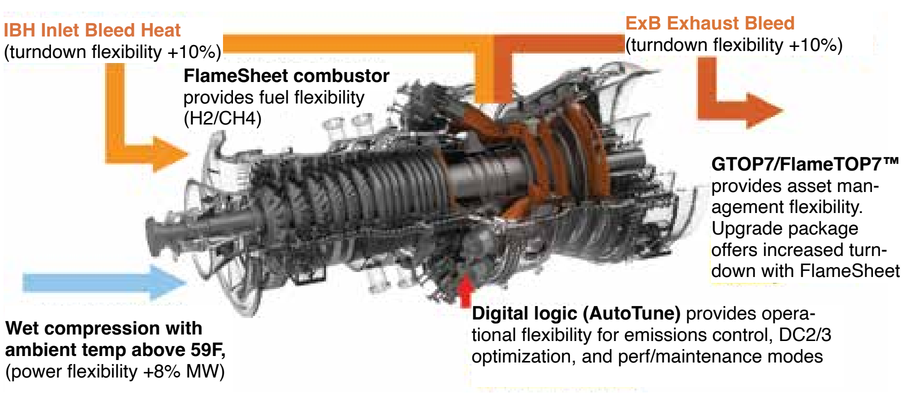
- Maintenance—32k hours, 9% simple cycle (SC) power boost, and 3.4% better heat rate.
- Performance mode—24k hours, up to 12% SC capacity boost, and 3.8% better heat rate.
- Peak mode—up to 13.6% SC power boost, and 3.8% heat-rate improvement. All of these improvements are possible without sacrificing a 9-ppm NOx emissions limit across the load range.

And PSM isn't stopping there. The next generation of GTOP (Fig 3) is incorporating FlameSheet™ Gen VII (FlameTOP7), plus new alloys for better resistance to low-cycle fatigue and creep, and additive manufacturing, and other techniques to speed up production capabilities. Uniform crystal temperature sensors embedded in TBC coated parts have validated lower metal temperatures in AM parts made using the latest techniques.

The first repair cycle of the next-gen GTOP7 first-stage vanes from the fleet leader's machine surpassed 25k factored fired hours (FFH) with minimal distress. Check out the photos in Fig 4 to see how the vanes looked coming out for inspection and repair. Overall, AM-produced vanes have been installed in over 13 machines with 132k operating hours and 2200 fired starts.

Duke Energy, Osprey Energy Center. As relayed by Jim Guevara, operations superintendent for Osprey Energy Center, and PSM's Chris Hagger, senior project manager, the plant needed more peak megawatts and minimum load adjustments to respond to the grid's summer morning solar output surges and afternoon solar dropoffs caused by thunderstorms. In the winter, the plant has to respond to high morning demand and lags in solar output.

Other goals of the GTOP7 and FlameSheet™ upgrade include keeping the GTs and ST/G online to maintain high availability, reduce dependence on the duct burners, improve heat rate, and extend low-end performance. Upgrade also included ExB, IBH, controls logic with disc-cavity modulation, AutoTune for maintaining emissions limits, refurbished rotor, and first-of-its-kind single-piece exhaust tooling.



2. Flexibility upgrades for the 501F. Operational flexibility can mean extending the turndown range, raising output for peaking capacity, co-firing hydrogen, and/or maintaining emissions compliance across an expanded operating range

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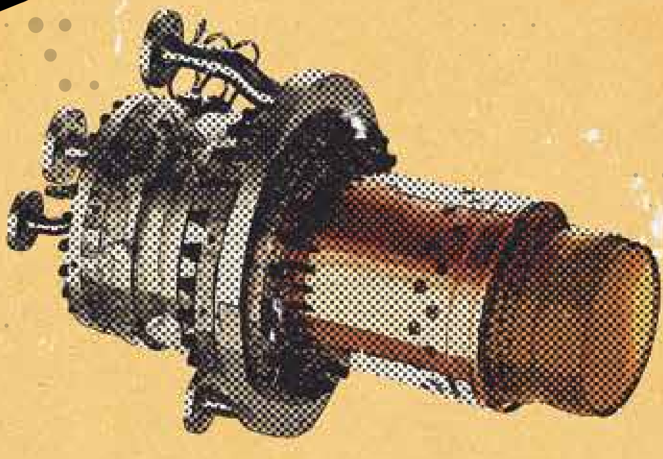

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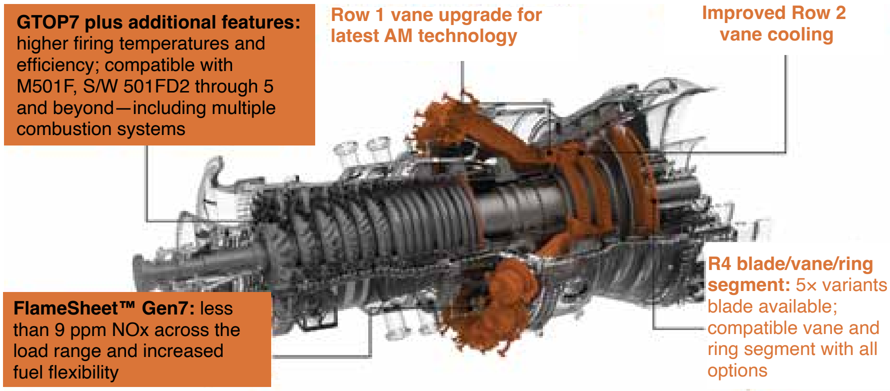


3. GTOP7 achieves higher firing temperatures and machine efficiency by incorporating new additive powders for critical HGP components

4. Critical GTOP7 components were in excellent condition after their first interval (more than 25,000 factored fired hours)

Osprey is a 2 × 1 combined cycle with two Siemens 501FD2 GTs, a Siemens KN steamer, and Nooter Eriksen HRSGs. After going commercial in May 2004, each of the GTs units has incurred more than 2400 starts and the ST/G more than 1900 starts.

After project completion, the plant tops out at 576 MW+ (up from 537 MW), over 600 MW with PAG and duct firing enabled, and turns down to 235 MW with IBH and ExB (from the earlier limit of 380 MW). This is a total of an operating range of 365 MW, all while holding sub-9 ppm NOx. To achieve the turndown levels, the ExB Flexline connectors (from the injection manifold to the bleed injectors) had to be replaced which came at a later outage and is now fully enabled on both units.

Major project activities and schedule (Fig 5) suggest the importance of the pre-outage planning phase, but of particular note is that the actual unit outages were 80 and 84 days with 10-15 days required for commissioning and startup.

Observations and lessons learned include the following:

- Close coordination is essential between dispatch and plant to comply with air permits during commissioning.
- The IBH manifold is best placed downstream of the duct silencer to reduce noise.
- The NH3 valve had to be re-trimmed by the valve OEM for lower reagent flows.
- Igniters demonstrated high reliability.

To date, Osprey is enabling the lowest turndown the plant can achieve most nights, changing the operating profile from the prior heavy starts operation to being able to remain online for quicker grid response.

Rocky Mountain Energy Center. Jeff Hall, Xcel Fleet Engineering Turbine Div, and Jose Ruiz, PSM's director of project execution, explained how the scheduled outage for Rocky Mountain (2 × 1, two 501Fs, one KN steam turbine) to install the FlameTOP upgrade revealed several other issues which had to be addressed: ST/G coupling alignment, need for a 4-way joint Superbolt™ solution, significant wear on hookfits, bearing damage, foreign object damage (FOD) on blades and diaphragms, and bearing damage.

Like many other system owner/operators, Xcel needed more dispatchable power from RMEC to follow its wind resources, but also wanted to extend inspection intervals from 24k to 32k, reduce ammonia consumption, and be prepared for future hydrogen co-firing. The presenters note that the key HGP upgrade within the project scope (Fig 6) was the additive manufactured R1 vane, which reduces cooling airflow.

The project achieved the stretch capacity goal (160 MW) for both units, a 1.62% heat-rate improvement, and turndown to 50 MW in Unit 1 and 45 MW in Unit 2 (with IBH and ExB). However, while both units are available, PSM and the plant were resolving emissions-performance issues with Unit 1. Distress found with some of the new hardware led to replacement of some parts and aggressive tuning efforts. This has since been resolved and both units are currently operating at sub-9 ppm NOx.

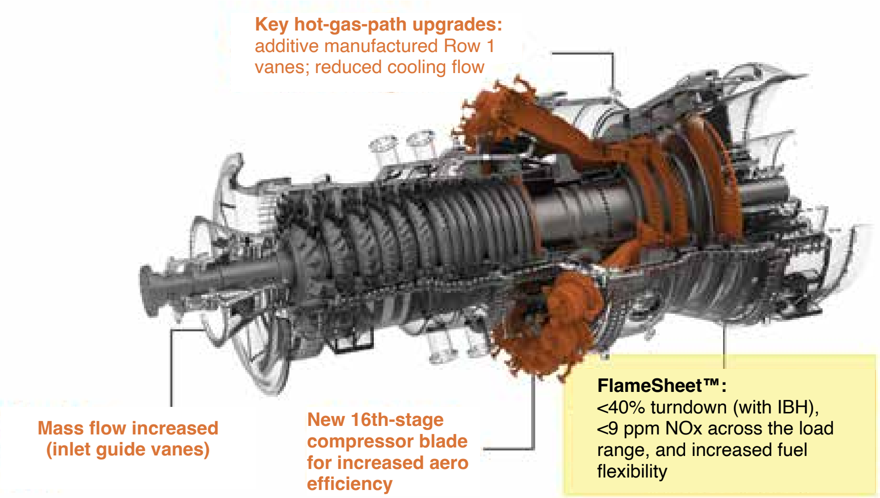
Included in lessons learned and observations are: Every unit is unique (with exclamation point), hookfit repair is challenging, pay attention to routing and securing thermocouple leads, carefully consider IBH positioning with respect to the silencers, and assess and understand the potential limitations of the BOP.

To close, PSM thanked Xcel Energy for this latest chapter in the 10+ year partnership between the two companies, which began with long-term parts exchange agreements and includes PSM support in more than 25 outages, and an extension of their agreement covering Xcel's 7FA simple-cycle units.

Rawhide station. Platte River Power Authority's Rawhide station includes four 7EAs and one 7FA for a combined 388 MW, 288-MW coal-fired unit, and 52-MW nameplate solar PV (22 MW effective capacity). Upgrade goal here, described in a qualitative way, is to allow the 7EAs to participate in the market "like aeros can." Practically, that means greater sustainable load range,

5. Planning/execution effort at Osprey involved the following activities:

Pre-outage planning, six to nine months.	*Outage event for GT2, 84 days; for GT1, 80 days.*	*Startup and commissioning, 10-15 days.*	*Post-outage support and commercial closure, two to four months.*
Development of an outage execution plan, readiness gate reviews, and site scanning; part-demand loading, scope alignment, division of responsibility, and extra work; third-party contractor work scopes and purchase agreements; hardware prep and delivery to site; safety training; final readiness review including GT commissioning plan.	Deployment of field-service and contractor teams to site; LOTO and GT disassembly; GT assessment and discovery; site build and install of IBH and ExB systems; GT reassembly and clearance/QC checks; weld inspection/pressurization tests of IBH and ExB.	Gas/fuel line checks; GT startup and tuning; vibration analysis (balance if required); commissioning with IBH and ExB across the load range.	Invoicing for base scope and extra work; final reports on field service, AutoTune O&M manual, tuning and commissioning, and controls; as-built drawings; operator training; lessons learned; maintaining reliability.



6. Upgrade scope for Rocky Mountain Energy Center GT, plus performance goals and machine upgrades implemented to achieve them—including FlameTOP, which consists of technology such as Additive Manufacturing (a form of 3D printing), modular design, and PSM's low emission, flexible combustion technology, FlameSheet™. Expectations included a 12% increase in output relative to the Model FD2 for a 24,000-hr maintenance interval

reduced emissions, and lower O&M costs. Low-emissions combustor (LEC) NextGen (replacing a DLN 1), sequential fuel injection (SFI), and AutoTune checked those boxes and Platte River decided to upgrade one unit.

The financial impact was considerable: The plant expects to save over $1-million in O&M costs over the course of a major outage interval. Essentially, the LEC NextGen avoids the combustor inspection (CI) at 12k OH/600 starts before the HGP (at 24k/1200 starts), and the CI at 44k/1800 starts before the major outage overhaul at 64k/2400 starts.

The unit not only exhibits lower emissions but is also now able to come into compliance earlier. The previous unit load range was 40-65MW; following the upgrade, it is 27-70 MW. No other performance attributes, such as heat rate, were sacrificed in attaining these goals.

Exhibits. The 2024 Asset Managers Conference was the first time PSM invited participation of their "partner" specialty product and services providers to the meeting. Here's a list of those companies:

- AGT Services.
- Vogt Power International.
- Advanced Turbine Support (Fig 7).
- Arnold Group.
- Mee Industries.
- National Electric Coil.
- Power Services Group.
- NexGEN.
- Alta Solutions.
- Industrial Air Flow Dynamics.
- Emerson.
- RMEC Environmental.
- Integrity Power Solutions.
- Hanwha Power Systems.
- PSM Thomassen Gulf. CCJ

7. Rod Shidler, president, Advanced Turbine Support, and Mike Hoogsteden, director of field services, share a laugh at PSM's first exhibition showcasing the specialty products and services offered by the company's partners

ASME accords Kansas combined cycle *Historic Landmark* status

The city of Ottawa's gas-turbine-powered combined cycle was honored as an Historic Mechanical Engineering Landmark by the American Society of Mechanical Engineers, Sept 13, 2024, in a special ceremony conducted in the Ottawa Memorial Auditorium. Dave Hunsaker, electric superintendent for the city, accepted the award from ASME Fellow Jared Oehring, a member of the society's Board of Governors (Fig 1).

1. Jared Oehring, a member of ASME's Board of Governors (left), and Dave Hunsaker, electric superintendent for the city of Ottawa (right), unveil the bronze plaque recognizing the Kansas municipality's combined cycle as a Mechanical Engineering Landmark. Blair Van Dyne (front row, far right) of GE Vernova, which designed and built the unit, looks on

The unit is the oldest extant unit of its type and representative of a major breakthrough in heat-engine design. The inscription on the bronze plaque (Fig 2), prepared by ASME's History and Heritage Committee, reads as follows:

The city of Ottawa, Kansas, 11 MW gas turbine combined cycle power plant (GTCC), consisting of the very first GE combined cycle, two-shaft, Frame 3 gas turbine, a heat recovery steam generator, and a GE Lynn steam turbine and GE electric generator, started operation in 1967.

This was the world's first pre-engineered GTCC to enter service. Using only one unit of fuel to power its two heat engines, GTCCs produce some of the highest power plant thermal efficiencies yet achieved by humankind.

Recognition as an ASME Historic Mechanical Engineering Landmark is a significant accomplishment (sidebar). Ottawa's combined cycle is the 283rd project so honored since the program's inception more than 50 years ago and only the second Landmark in the state of Kansas.

The first, Landmark No. 127 (1987), is the Big Brutus mine shovel. Its 90-cubic-yard bucket removed 135 tons of overburden with each scoop in the surface mining of coal from 1963 to 1974.

Gas-turbine history

The transition from fossil-fuel-fired electric generation based on the Rankine cycle to the Brayton cycle began in 1939 with commercial operation of the municipal power station in Neuchâtel, Switzerland.

This was the world's first successful use of a gas turbine to drive an electric generator. The 4-MW simple-cycle plant had an efficiency of 17.4%. It was designated by ASME as Mechanical Engineering Landmark No. 135 in 1988 (sidebar).

Gas-turbine developments came quickly after World War II, motivated by the booming military and commercial aviation industries. At General Electric, a group of engineers who had participated in the design and development of aircraft jet engines began work on a gas turbine suitable for industrial and utility service.

While many of the metallurgical advancements and technologies developed by the aviation industry could be applied to land-based gas turbines, ruggedness and long

Landmarks highlight significant historic mechanical engineering achievements

ASME encourages public understanding of mechanical engineering and fosters the preservation of its heritage. The society formed a History and Heritage Committee of mechanical engineers and technology historians in 1971 to examine, record, and acknowledge achievements of particular significance.

ASME's technology library at www.asme.org/about-asme/engineering-history/landmarks offers a fascinating trip through the history of mechanical innovations that have influenced the development of civilization and industry, as well as public welfare, safety, and comfort.

Mechanical Engineering Landmarks are existing artifacts or systems representing significant technological accomplishments. Often, they are the last surviving examples of an important device, or machines with some unusual distinction.

H&H committee members participating in the evaluation of the Ottawa combined cycle for Landmark status included the following:

- Lee S. Langston.
- Thomas H Fehring, PE.
- Marco Ceccarelli.
- Martin C Ross, PE.
- Robert T Simmons, PE.
- Terry S Reynolds.
- Herman Viegas.

2. Dave Hunsaker, Ottawa's electric superintendent, conveys the plaque's inscription to those participating in the ceremony

life, rather than light weight, were the important design considerations for power generation. The blending of jet-engine and steam-turbine designs resulted in what came to be referred to as heavy-duty gas turbines for on-ground applications.

Perhaps the earliest use of these ruggedized engines for electric generation was in GT-electric locomotives. First demonstrated in 1948, Union Pacific went on to purchase several dozen locomotives from ALCO (American Locomotive Co) with GE providing on-base gas-turbine power to the motors for long rail deliveries in the West.

These machines soon fell out of favor with the public, according to some industry experts, because of the high-frequency noise generated by the gas turbines' axial-flow compressors. An inlet-silencing solution was not introduced until late in the 1950s when gas turbines for rail application already were being forced into retirement.

By contrast, electric power producers welcomed gas turbines, as did companies involved in gas/oil transmission where they were valued as drivers of pumps and compressors. The first GT installed by a US electric utility was applied in a combined cycle at Oklahoma Gas and Electric Co's Belle Isle Station in 1949.

But this was not one of today's combined cycles. Energy in the exhaust gas from the 3.5-MW gas turbine (a GE MS3001, a/k/a Frame 3) was used to heat feedwater for a 35-MW conventional steam unit. OGE doubled down on its innovation in 1952, repowering another Bell Isle unit in the same manner.

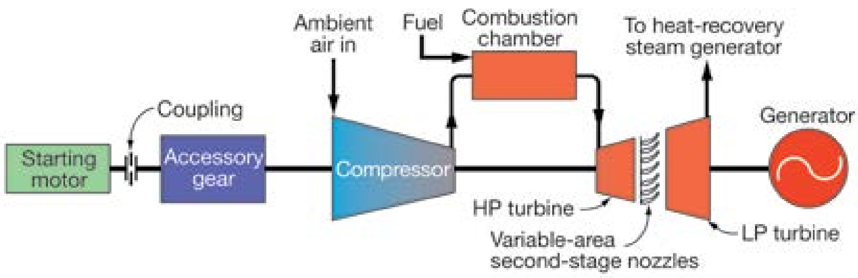
Most early combined-cycle systems were adaptations of conventional steam plants with the GT exhaust serving as combustion air for their fully fired boilers. The efficiency of this type of combined cycle was about 5% to 6% higher than that of a similar conventional steam plant. These systems could use bare boiler tubes economically because of the high mean temperature difference between the combustion products and the water/steam.

Equipment to economically weld continuous spiral fins to tubes was introduced to boiler manufacturers in 1958, enabling the next step in combined-cycle design. So-called heat-recovery combined cycles, capable of capturing the sensible heat in GT exhaust gas, were made possible by welded finned tubes.

For engineers knowledgeable in thermodynamics, this was big: Fueling a gas turbine with natural gas and using its exhaust gases to make steam to drive a steam turbine provides two prime movers to generate electricity using only one unit of fuel. This combined-cycle arrangement currently has yielded the highest thermal efficiency of any heat engine that has ever been produced, and is the one preferred today by electric power producers.

Today's three leading suppliers of large combined-cycle powerplants—GE Vernova, Siemens-Energy, and Mitsubishi Power—all offer units with thermal efficiencies in the 60% to 65% range.

GE introduced the pre-engineered combined cycle to the electric power industry in 1967 under the tradename STAG (STeam



3. The two-shaft MS3002 gas turbine selected for Ottawa is well suited for combined-cycle application given its exhaust-temperature control feature

And Gas). Less than four years later it had four competitors: Westinghouse Electric Corp, Turbo Power and Marine Systems Inc (a subsidiary of Pratt & Whitney), Turbodyne Corp (affiliated with Brown Boveri-Sulzer Turbomachinery Ltd and Worthington Turbine International Inc), and Stone & Webster Engineering Corp.

But GE had the only success story among the firms offering *pre-engineered* combined cycles. Its first two systems were rated 11 and 21 MW, both incorporating one gas turbine (Frame 3 for the smaller unit, Frame 5 for the larger), one heat-recovery steam generator (HRSG), and one steam turbine/generator.

The city of Ottawa (Kansas) commissioned the first STAG unit (11 MW) in 1967 (a Model 103) and opened the proverbial flood gates for pre-engineered systems, with unit sizes growing exponentially in short order.

Example: Jersey Central Power & Light ordered the first multi-shaft STAG unit (four gas turbines, one steam turbine), rated 340 MW in 1971. By the end of 1974 15 more STAG systems (single- or multi-shaft configuration) were ordered by eight utilities. The largest had eight gas and two steam turbines with the capability to produce nearly 600 MW.

The bottom line: In less than a decade, the industry-wide combined-cycle "movement" launched by a small midwestern municipal utility was installing power-generation systems 50-fold larger.

Commercial success. Ottawa demonstrated the efficacy of a pre-engineered combined cycle of relatively simple design for producing electric power reliably and at low cost in baseload service. Its power train, consisting of a starting motor, MS3002 gas turbine, reduction gear, axial-flow steam turbine, and generator powered by both the gas and steam turbines, is base-mounted, with components arranged in tandem on a single shaft (Figs 3-6).

The unit generated 11.5 MW at the unusually low net plant heat rate (for that time) of 11,280 Btu/kWh, yielding an outstanding thermal efficiency of 30.25%. The careful integration of proven components, a STAG feature, contributed to the plant's low installed cost—quoted at $1.745 million.

Important to note is that Ottawa's guaranteed heat rate, based on the higher heating value of natural gas, 1000-ft elevation, and 80F ambient, was a 12% to 18% improvement over comparable steam plants. Recognize that Ottawa was designed prior to acceptance of ISO standards which calculate GT performance based on a sea-level location, 59F ambient, and 60% relative humidity.

Ottawa's STAG Model 103 has a two-bearing, statically excited, air-cooled generator with the gas turbine coupled to the forward end and the multi-stage steam turbine to the aft end. The latter, which has 14-in. last-stage blades, has no throttle control valves. They are unnecessary as steam pressure varies over the load range in direct relation to the GT exhaust temperature.

This results in a constant volume flow of steam entering the unit during normal operation. The steam inlet is equipped with a

4. Looking down at the combined cycle the gas turbine is at the left, generator at the right

5. Gas-turbine exhaust end is to the right of the reduction gear

6. Generator is at the left, steam turbine and condenser at the right, looking down the combined cycle on the operating floor

stop valve and motor-operated trip throttle valve for control during starting, and complete protection in the case of a full-load or overspeed trip.

The steam turbine exhausts axially to a floor-mounted condenser. A single-cell induced-draft cooling tower and full-size circulating-water pump supply the total cooling-water flow requirement of the condenser, gas turbine, generator, and all Rankine cycle accessories.

An extended-surface heat-recovery steam generator (HRSG) recovers thermal energy from the nominal 970F gas-turbine exhaust gas to produce 46,500 lb/hr of 400-psig/820F steam—assuming the unfired HRSG receives the design-basis exhaust-gas flow of 382,500 lb/hr and feedwater at 110F. Demineralized makeup water is supplied to the HRSG. Note that the HRSG, as well as the gas and steam turbines, were made by GE.

Ottawa's modular HRSG, no longer a GE product, offered the benefits of reduced installation time and cost. The boiler was non-radiant, so refractory and waterwalls were not required. Forced circulation and small-diameter finned tubes contributed to a compact, shippable boiler for exhaust-gas flows up to about 1.5-million lb/hr—or about four times that required by Ottawa.

Plus, unrestrained headers of intermediate thickness and all-welded construction eliminated direct tube-to-steam-drum joints while minimizing the effects of thermal shock.

The MS3002F consists of a so-called HP turbine set—it incorporates a 14-stage axial-flow compressor, combustion section, and HP turbine—and the LP turbine, which is connected to the generator. HP turbine inlet temperature is 1600F when the unit is at baseload. Exhaust gas exiting the HP section flows through variable-area, second-stage nozzles before entering the LP turbine (refer back to Fig 3).

The two-shaft gas turbine, most commonly applied in gas-compression and pumping service, is particularly well-suited to a combined-cycle application because of its exhaust-temperature control feature. By varying the angle of the second-stage nozzles, it is possible to maintain nearly constant exhaust temperature (and steam conditions) over much of the load range. Part-load performance is improved considerably by holding the steam conditions constant.

The HP turbine set has three bearings and turns 6900 rpm; the two-bearing LP turbine,

7. One combustor manifold is located on either side of the engine

which operates at a nominal 6000 rpm at rated load, is connected to the 3600-rpm generator through the reduction gear shown in Fig 5. The generator is rated 13.5 MVA, 12.5 kV, 0.85 pf.

Once synched to the grid, the LP turbine shaft has to run at precisely 5979 rpm for the generator to produce 60-Hz power. When load is increased or decreased, HP turbine speed and the variable-area, second-stage nozzles respond to maintain LP turbine speed.

Combustion system for the MS3002F is unique. There are three combustors on each side of the engine. Two of the three chambers on each side have spark plugs; the third has a flame detector (Fig 7).

The STAG 103 came equipped with dual-fuel capability. When the combined cycle was installed, the city generated all of its power, which it did until 1979, with the GE unit in baseload service. Once Ottawa began purchasing power from the grid, the STAG 103 was relegated to peaking service and the faster-starting recip engines (two rated 6 MW, one 3.6 MW and one 3 MW) better suited for this type of service were dispatched ahead of it. The engines can be at full power in five minutes; it takes the STAG 103 about 45 minutes for a cold start.

The accessory base contains the necessary auxiliaries to start and operate the unit (Fig 8). An ac starting motor is coupled through an accessory gearbox to the HP turbine shaft at the compressor end. Motor-driven lube-oil pumps, lube-oil cooler, and oil filter are located above the oil reservoir.

The original control system had at its heart a mechanical/hydraulic control device known as a Fuel Regulator, manufactured by Young & Franklin. It controlled fuel flow, and the power output of the LP turbine. HP turbine speed was controlled by another Y&F device: a nozzle regulator. In 1992, Ottawa upgraded to a Woodward NetCon control and protection system to improve starting reliability. Conversion of the gas turbine from dual fuel to gas-only was accomplished at this time as well.

Operation. Startup of the STAG 103 is semi-automatic. More specifically, many of the functions and operating sequences are manual with several sub-loop operations automatically sequenced and performed. Startup permissives include having turning gear "off" and key equipment in operation.

The unit then is cranked for starting by a 250-hp electric motor. When it reaches about 25% of rated speed, retractable spark plugs ignite the fuel/air mixture in four of the six combustion chambers. Crossfire tubes ignite the combustible mixture in the unfired chamber in each bank.

Ignition is maintained for a short period. When combustion becomes self-sustaining, the unit automatically comes to the so-called warm-up condition with the HP turbine set held at reduced speed and firing temperature until steam is produced and all required pre-acceleration conditions are in effect. At that point, gas-turbine acceleration is initiated manually and the STAG 103 comes up to governing speed. The generator is synchronized manually.

Maintenance history. The most recent borescope inspection, conducted by Dave Lucier of PAL Turbine Services about a dozen years ago, found no surprises and concluded that the gas turbine was fit for duty.

The last hot-gas-path inspection had been

8. Accessory base contains the auxiliaries for starting and operating the gas turbine

conducted early in 2001. At that time, maintenance personnel found the engine dirty but in good condition, especially considering the number of hours since the previous overhaul. Some erosion of compressor blades was noted and the HP- turbine bucket tips had rubbed on the lower shroud blocks. Plus, all buckets were frozen in the dovetail fits. The rotor was overhauled in a Houston shop.

Work also was required in the combustion section. Small cracks in liners and transition pieces required repairs, and there was other heat-related damage as well. Bearing wear was in evidence, too. The load-carrying surfaces of journal bearings 1, 2, and 3 were repoured after inspection. Contractor personnel believed that bearing issues contributed to accessory-coupling misalignment and wear and it was targeted for replacement or repair.

End notes. The Ottawa combined cycle was the first of only two STAG 103s made by GE. The second was installed by the City of Hutchinson (Minn) in 1971. Industry demand at that time was for larger power generation systems. In fact, after 1972, no pre-engineered combined cycles smaller than 100 MW were ordered by US utilities. Economy of scale ruled.

Ottawa logged only about 11,000 operating hours after hitting its 100,000-hr milestone at the end of 1993. This industry icon was retired in place in 2020, after spending two decades in standby service. It was started periodically for training and equipment-preservation purposes.

Hutchinson's STAG 103 was taken out of service in 2019 and has been dismantled.

Today the city of Ottawa (2020 population, 12,625) purchases most of its power for its 6400 meters from the Grand River Dam Authority, Western Area Power Administration, Southwestern Power Administration, Kansas Municipal Energy Agency (Marshall Wind Farm), and the Buckeye Wind Energy Center. The municipal's four engines remain in standby service.

The city also owns a 5.2-MW share of Dogwood Energy Center, Pleasant Hill, Mo. It is an efficient 650-MW, natural-gas-fired F-class combined cycle.

Ottawa receives 161-kV power at two of its three interconnections and 35-kV power at the third, which is located at the generating plant. Distribution throughout the city is via about 12.4- and 4.6-kV lines. CCJ

Acknowledgements

Compiling the history of the Ottawa combined cycle involved the work of many people, especially the following:

- City of Ottawa. Dave Hunsaker, Leon Wildeman (ret).
- ASME H&H Committee (inactive). Lee Langston, Tom Fehring, Steve Walton, Virginia Ross.
- GE. Bob Johnston (ret), Dave Lucier (ret), Tom Freeman.

Seventh International Conference focuses on research required to advance use of FFS

By Steven C Stultz, Consulting Editor

The seventh annual International Conference on Film Forming Substances (FFS), conducted in Prato, Italy, March 26-28, 2024, was developed and supported by the International Association for the Properties of Water and Steam (IAPWS). The meeting drew 50 participants from 16 countries—including 10 plant owner/operators and representatives from a dozen chemical suppliers.

The event was chaired by Barry Dooley, Structural Integrity (UK), and David Addison, Thermal Chemistry (New Zealand).

Says Dooley, "The major activities at FFS 2024 were multiple presentations and discussion sessions outlining the current status of FFS and their properties in relation to their application as corrosion inhibitors in fossil, industrial, nuclear and other water/steam plants."

Film-forming substances consist of two main categories of chemicals using the internationally accepted nomenclature: amine-based (FFA, film-forming amine, and FFAP, film-forming amine products), and non-amine-based (FFP, film-forming products) which are proprietary.

Selected conference highlights follow.

Hydrophobicity

Two significant hydrophobicity aspects were stated by Dooley in his conference review:

1. "As at previous FFS conferences, there were general visual observations of hydrophobic films in the water-touched areas (mainly feedwater and condensate) of plants" (Fig 1).

2. More importantly, "A survey of conference participants indicated that the presence of hydrophobic films does not uniquely relate to the reduction of corrosion and the transport of corrosion products but appears to be an artifact of application. Also, surface tension of an FFA (OLDA) is reduced at low levels and related to the contact angle of wettability in this range," Dooley explains.

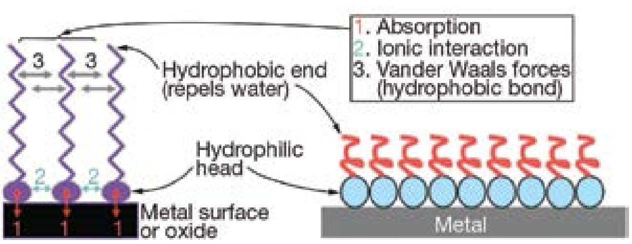
And moving beyond the visual, he continues: "A deeper understanding among the attendees was apparent around what are the metrics for success for an FFS program in plants and moving beyond just using the presence of hydrophobicity as a single assessment point."

Testing methods and analysis were common topic points in many presentations.

Analysis with EIS

Again, citing Dooley, laboratory experiments discussed at FFS 2024 "provided positive results on monitoring OLDA adsorption onto oxide surfaces, corrosion, and corrosion kinetics using EIS (Electrochemical Impedance Spectroscopy). The work on the interaction of the FFA with oxide surfaces rather than metal surfaces was strongly encouraged especially for the other FFS."

This method was presented on the first day by Deni Jero et al (Université de Toulouse, France), entitled *Electrochemical impedance spectroscopy for continuous in-situ analysis of FFA on carbon-steel surfaces.*



1. Visible hydrophobicity (shown here) does not necessarily mean protection

Jero looked at water/steam circuits of industrial facilities (carbon steel), localized corrosion, and consequences (materials degradation and damage risk). This led to protection strategies— including the use of film-forming amines.

The challenge, she says, is "continuous in-situ analysis of FFA, of nanometric thicknesses, on rough and corrodible surfaces" for the characterization of thin organic layers.

The proper process must be specified for:

- In-situ (in immersion and continuous).
- Sensitivity to layer thicknesses.
- Working in a surface roughness environment.
- Ability to differentiate between adsorption and corrosion.
- Designed for structural characterization, in this case also using OM-IRRAS (Polarization Modulation Infrared Reflection Absorption Spectroscopy).

The analysis technique discussed: Electrochemical Impedance Spectroscopy (EIS).

The study focused on the following:

1. OLDA (Oleyl Propylenediamine) adsorption kinetics and structural properties.
2. Influence of temperature variation on the OLDA layer.

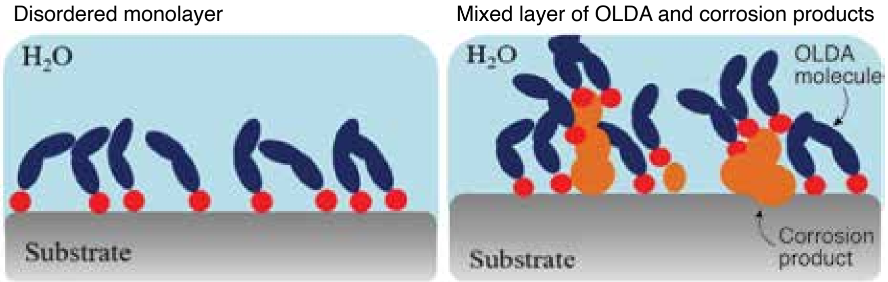
General conclusions showed the mixed layers of OLDA and corrosion products, simplified in Fig 2.

The conclusion of this study: For optimization of FFA quantity and injection frequency, EIS is a useful tool to monitor FFA on carbon-steel surfaces.

Other applications in water/steam cycles

Successful applications of FFS for industrial-boiler pre-service cleaning and preparation, and for waste incineration boilers, were discussed for the first time at an FFS conference.

Industrial pre-commissioning cleaning



2. Structural characterization of FFA on carbon-steel surfaces was by in-situ Electrochemical Impedance Spectroscopy (EIS), confirmed by Polarization Modulation Infrared Reflection Absorption Spectroscopy (PM-IRRAS).
Source: Jero, et al, Electrochim, Acta (2023) 141925

Dylan Harrison, Visentia Ltd, New Zealand, discussed *Pre-commissioning cleaning of new industrial boilers with the use of ODA (Octadecylamine)*.

His case study was a 30-MW biomass boiler (Fig 3).

Traditional pre-commissioning boilouts (various chemistries) are intended to remove mill scale, iron oxides, slag, abrasing dusts, greases and oils, and manufacturing debris—such as nuts/bolts/washers/tools. This also helps minimize corrosion during refractory drying.

3. 30-MW wood-fired facility in New Zealand

Harrison offered a comparison of results, alkaline/phosphate versus ODA treatment boilout, shown in the table. His discussion included lessons learned, along with cautions and solutions.

Waste-to-energy

F Carruba, Kurita Europe (Italy) and V Di Massa, Ecologia Oggi (Italy) presented *Transition of two waste-incineration boilers in Italy from traditional treatment to Cetamine*®. The 16-MW municipal solid waste plant (Fig 4) was commissioned in 2005, with two boiler systems.

Boilout is intended to remove macroscopic residues from the system (deaerator, drums). Overall, changing the procedure with Cetamine reduced chemical consumption by 97%, water consumption by 55%, and boilout time by 54%.

Presenters explained that in September 2022, the plant switched from standard boilout procedure to boiling out with Cetamine. At the end of 2022 the plant switched to Cetamine for both passivation and continuous treatment and "total iron levels in the system were significantly reduced."

Cetamine was shown as suitable technology during the process of alkaline boilout, passivation, and continuous treatment. All steps can be covered with one product, and the change allowed significant reductions in chemicals, water, and time.

Selected plant updates

Anthony Senecat, Engie Laborelec, began the FFS 2024 sessions with *Two cases of FFA use in Engie power plants*: A 2 × 1 combined cycle commissioned in 1998, now in flexible operation (daily start and stop), and a nearly-retired coal-fired station commissioned in 1979.

In the first (Fig 5), iron values were compared from 2008 to 2018, before and after FFA dosing. A consistent evaluation between feedwater and condensate showed a positive impact of FFA on iron transport.

The second plant (Fig 6), originally baseload, is now limited to support for a neighboring blast-furnace-gas boiler. Dosing is used to minimize preservation costs for the water/steam cycle when offline.

In this case, dosing implementation has been difficult with large deviations in CACE (conductivity after cation exchange) readings. In summary, "FFA implementation is not a straightforward process." There is to date no explanation of the high degassed CACE values. However, dosing FFA prior to the end of continuous operation appears beneficial to the water/steam cycle.

Berkeley Booth, Veolia (US), presented *Polyamine Plus controls corrosion in large utility boiler.* Subject plant: The four-unit 2400-MW coal-fired Jim Bridger Plant of Rocky Mountain Power, a subsidiary of PacifiCorp. The plant operates in flexible mode with the 600-MW boilers operating as low as 80 MW on any given day.

Polyamine Plus is a unique blend of FFA and non-amine filming product. Discussed was Steamate PAP7010. Says Booth, "After eight months of feeding PAP7010, the condenser hotwell, feedwater, boiler, and steam turbine were inspected for evidence of product coverage."

The feedwater heater and other locations, including stream turbine and condenser, had visual presence of hydrophobicity.

This implied "protection over the entire steam system" with cost savings. Following the first unit test, all boilers were switched over to PAP7010. Dosage was optimized to 0.5 ppm.

Other updates on recent FFS experience included applications for supercritical units, "raising questions on additions of FFP when using oxygenated treatment."

Boilout comparisons, alkaline/phosphate versus ODA

	Alkaline/phosphate	ODA
Roll and mill scale	Removed	Incorporated
Oils and greases	Removed	Removed
Iron oxide deposits	Removed	Removed over time
Ecotoxicity	High	Low
Effluent management	High	Low
Chemical volume required	High	Low
Chemical testing during boilout	Easy	Easy
Corrosion protection between boilout and online	Medium	High

For example, Nalco's David Little discussed *Non-amine filming for supercritical power plants* featuring a 950-MW unit with varying load in Pennsylvania and another coal plant in the Midwest operating between 400 and 800 MW. He offered "A tale of two stations" and use of Powerfilm 10000, both meeting trial objectives with positive results.

Both trial units suggest that supercritical applications should be limited to non-amine FFPs. Trials are ongoing.

David Addison, Thermal Chemistry, presented *Application of ODA in an 8-MW electrode boiler* in Queenstown, New Zealand. This trial is ongoing.

One conclusion: "Successful initial application of ODA to resolve commissioning chemistry issues" showed a "sudden and effective reduction in corrosion rates (total iron levels) when applied."

4. Waste-to-energy plant serving Gioia Tauro, Italy

5. 2 × 1 combined-cycle plant was commissioned in 1996

Rounding out the sessions

Fulfilling the comprehensive 2024 agenda were the following:

- *Environmental and ecotoxicity wastewater considerations* (Thermal Chemistry, New Zealand).
- *ODA in secondary circuit: Efficiency against corrosion in layup* (EDF Research, France).
- *FFA behavior in water/steam cycle using a recirculating loop* (Canadian Nuclear Laboratories, Canada).
- *Available FFA analytical methods* (Reicon, Germany).
- *Application of FFP/amine in two cooling systems* (Evides Industriewater, The Netherlands).
- *Filming product application in PWRs/PHWRs* (IPRI, US).
- *Impact of FFA on (nuclear) steam-generator sludge properties* (EDF, France).
- *Flow-accelerated corrosion in aqua ammonia systems* (Yara, The Netherlands).
- *FFS: Needed research and improved operation* (Dooley and Addison).
- *Dosing, monitoring, and control—a practical approach* (Wolfgang Hater, Germany).
- *Acting for an ethical water performance* (Odyssee Environmental, France).
- *FFS as an efficient heat-transfer enhancer* (Kurita, Japan).
- *Photometric methods for detecting FFAs in water* (University of Belgrade, Serbia).
- *The effect of adsorbed OLDA on contact angle* (MHI Group, Japan).
- *Impact of various FFS on condensation* (Nalco Water, Australia).

Ongoing work and IAPWS

One of the leading questions among users worldwide remains whether FFS application can be changed from an FFP to an FFA, or vice versa, for economic reasons.

A panel discussion held on the final day of FFS 2024 covered the following, itemized by Dooley: The seven-year suite of FFS international conferences has been a key part in the development of the IAPWS Technical Guidance Documents (www.iapws.org) and has helped to advance proper use of FFS as part of the aims of the IAPWS Certified Research Need (ICRN), which was scheduled for completion and approval at the IAPWS 2024 meeting, June 23-28, in Boulder, Colo.

This ICRN is intended to help drive additional research into the critical, currently unknown fundamentals of FFS which will help to lower the application risks in plants, reduce failures, improve the performance of applications and eventually allow FFS to be changed at plant sites.

An outline of the research requirements, provided by Dooley, follows:

- Effect of FFS on growth mechanisms of Fe, Cu, and Cr oxides in water and steam. Better understanding will help to explain the effects of surface roughness and overdosing of FFS. This is recognized as the current major deficiency in understanding how FFS work in providing protection. Future work is needed on the interaction of FFS films with existing oxide/deposit surfaces of Fe_3O_4, Fe_2O_3, FeOOH, CuO and CuO_2 in condensate/feedwater and boiler/evaporator water environments.
- Relation between surface coverage and degree of corrosion protection.
- Effect of FFS on boiler and HRSG tube failures (under-deposit corrosion and corrosion fatigue) and stress-corrosion cracking.
- Film formation, kinetics, structure, equilibrium and stability (film thickness and porosity on water- and steam-touched oxide surfaces) for all FFS, especially FFP.
- Thermal hydrolysis and decomposition products for FFA, and especially FFP under oxidizing and reducing potential conditions.
- Uncertainty of adsorption onto oxide surfaces for all amine and non-amine FFS and how films are affected by other additions to the FFS.
- Characteristics of film layers and correlation with surface protection.
- Whether protection of superheated steam surfaces can be achieved for amine and non-amine FFS.
- Increased steam-turbine performance for amine-based FFS (ODA) has been illustrated but research is needed to determine if other FFS reduce the surface tension.
- Impact on membranes (EDI and RO).
- Impact on ion-exchange resins.
- Compatibility of FFS with other chemical additives (for example, chemical cleaning agents and dispersants).

Wrap-up

The FFS conferences are developed and supported by the International Association for the Properties of Water and Steam (IAPWS). FFS 2024 was arranged in Prato, Italy, by Mecca Concepts, Australia, and Combined Cycle Journal, US. Sponsors of FFS 2024 were Swan Analytical Instruments, ECOLAB, Kurita, and Anodamine.

Conference information is available at https://filmformingsubstances.com.

Contact Barry Dooley (bdooley@IAPWS.org or bdooley@structint.com) for further information on FFS and the IAPWS FFS conferences. CCJ

6. Engie Electrobel coal-fired station went into service in 1979

Protecting metal surfaces touched by water, steam in boilers, piping systems

If you have been following CCJ's coverage of film forming substances over the past several years (see previous article), you're aware of the value of these chemicals in protecting metal surfaces. If not, you can come up to speed quickly by watching the four webinars on "Mastering Film Forming Amines" hosted by Ronny Wagner, managing director, Reicon Leipzig GmbH, which can be accessed via the QR codes provided here.

Reicon has more than 40 years of experience in research and application of Octadecylamin (ODA)-based film forming amines and Wagner is recognized worldwide for his work in this technology.

By way of background, filming amines and products provide corrosion protection by forming a physiochemical barrier between metallic surfaces and the working fluid (water) to prevent corrosion from occurring. Filming amines and products also can provide a film on steam-touched surfaces and offer protection against oxygen pitting when boilers are offline and exposed to humidified air or water formed via condensation.

What follows is an outline of topics included in each webinar to guide your involvement.

Webinar 1, Basics and guidelines

- What is an FFA and what is not? Explains the differences among film forming amines, film forming amine products, and film forming products.
- How do FFAs work? The adsorption process is addressed first using simple diagrams to describe physisorption, chemisorption, and multilayering. Explanation of corrosion protection is next, then cleaning effect and impacts of droplet diameter and droplet condensation.

Final dozen slides in this webinar focus on FFS standards developed by the International Association for the Properties of Water and Steam (IAPWS), an organization respected by powerplant owner/operators. Its Technical Guidance Documents (TGD) are invaluable and available at no cost from www.iapws.org.

Webinar 2, Analysis procedures

Focus is on the basics of FFA analysis: (1) What's being measured, (2) Standards and guidelines available to guide your decision-making, and (3) Specialties for sample-taking.

Regarding the first point, keep in mind that only residual concentrations in water or steam can be measured. The only available guidelines today are IAPWS TGD 8-16 (2019), "Application of film forming substances in fossil, combined-cycle, and biomass powerplants" and TGD 11-19 (2019), "Application of film forming substances in industrial steam generators."

Two laboratory analysis methodologies are mentioned: Extraction method with methyl-orange (Silverstein Method) and Xanthene dye reaction (Bengal Rose Method). For more information, see Section 8.5 of TGD 8-16.

Field tests cited are the Lovibond Tablets Test, which is not suitable for concentration determination in FFA applications in steam and hot-water boilers, and the Chemetrics Filming Amine Test. The Waltron Filming Amine Analyzer is mentioned for online measurement.

Webinar 3, Continuous dosing under cycling operation

Covers the application guidelines on (1) Possible injection points, shown on a cycle diagram, (2) Dosing recommendations for different operating scenarios, and (3) restrictions and challenges to keep your plant operating as intended. The last gives very specific guidance. For example, FFAs start to thermally decompose at temperatures greater than 750F.

Webinar concludes with two case studies of interest to plant operating teams—one a combined cycle in flexible operation, the other a biomass plant with seasonal peak-load operation.

Webinar 4, Preservation procedures

Application guidelines are continued in this segment of the webinar and begin by answering the question: Why use FFAs for material preservation? Reasons include: Offline corrosion starts immediately following plant shutdown, pitting initiated by offline corrosion is a starting point for turbine damage, to reduce the amount of corrosion product transport during startup.

Ronny Wagner told webinar participants that four main factors influence the preservation effect: FFA concentration, time, temperature, and water quality. He then offered preservation procedures and highlighted restrictions and challenges to be aware of.

Webinar concludes like the previous one with two case studies—one discussing a coal-fired station with extended layup and the caveat that the 780-MW unit might have to restart quickly to provide grid support. The second unit is a 390-MW lignite-fired plant. Its preservation goal: provide capacity reserve in accordance with German law while protecting the water/steam cycle against corrosion for four years. The recommissioning time allowed is less than 10 days.

Photos shown during the presentation revealed that all observed surfaces continued to show hydrophobic behavior after two years of layup. There were no signs of corrosion in pumps or condensate lines; feedwater showed no evidence of rust. CCJ

Effect of hydrogen combustion on thermal barrier coatings

Decarbonization of the electric power industry will increase the use of hydrogen as a gas-turbine (GT) fuel—alone or in combination with natural gas. Issues for hot-section components when burning hydrogen include the following: increased flame speed, temperature, quenching distance, steam in combustion products (from 12% to 21%), and loading.

The resulting increase in erosion and heat transfer to base materials and coatings, and the durability of the thermal barrier coating (TBC) applied to hot-gas-path (HGP) components, is an industry concern.

A durability test was initiated by TEServices, La Porte, Tex, to determine if the following coatings can withstand a hydrogen environment: (1) Conventional yttria-stabilized TBC Y for mature gas turbines, and (2) Advanced rare-earth-stabilized TBC K for the latest GT models.

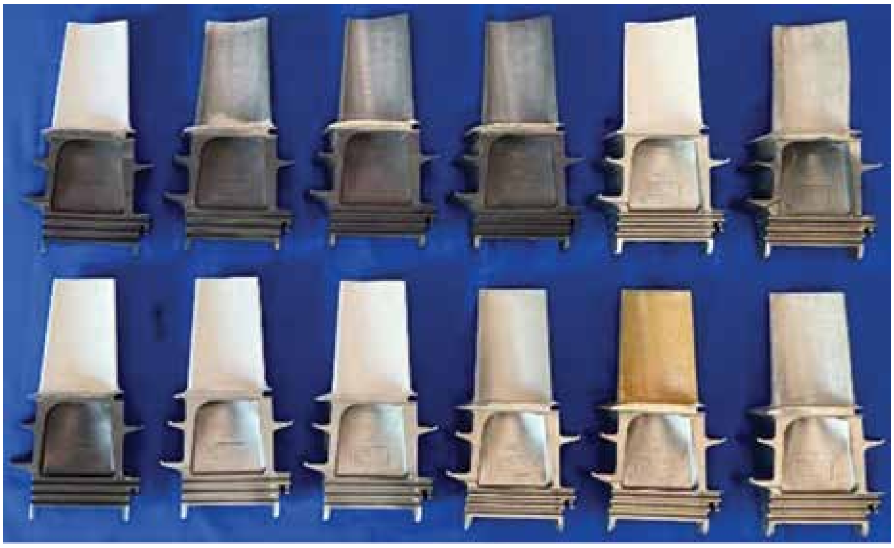
With Dominion as the host and EPRI the sponsor, eight participants (Honeywell, Liburdi, PSM, Cincinnati Thermal Spray, APG, Doosan, MD&A, and Sulzer, and the baseline OEM) provided a dozen different coating applications for this test. Five are conventional dense vertical cracked (DVC) TBC Y—including one OEM-applied DVC TBC—and seven advanced, combination DVC/TBC K coatings on GE 7F.03 first-stage buckets (S1B).

The initial borescope inspection provided promising results (Fig 1 and the table). This article is the first of five planned on the subject. Mission of TBC Rainbow Test I (2024) is to introduce the program, install the buckets, and provide the first borescope results. The remainder:

- Test II, with borescope results at the halfway point in the program (2023-2025).
- Test III, lab testing (phase change and thermal conductivity).
- Test IV, final borescope results (2023-2027).
- Test V, final results—including metallurgical evaluations, etc.

First-article inspection (FAI) on the actual parts must be performed to ensure the coating application will promote successful turbine operation. Recall that most conventional coatings currently are applied on 7F.03 S1B airfoils and other HGP parts; however, optimum thermal-spray settings and robotic programs had to be developed for advanced coating systems in this test (Fig 2).

Metallurgical evaluation of the bond (applied by high-velocity oxygen fuel, HVOF),

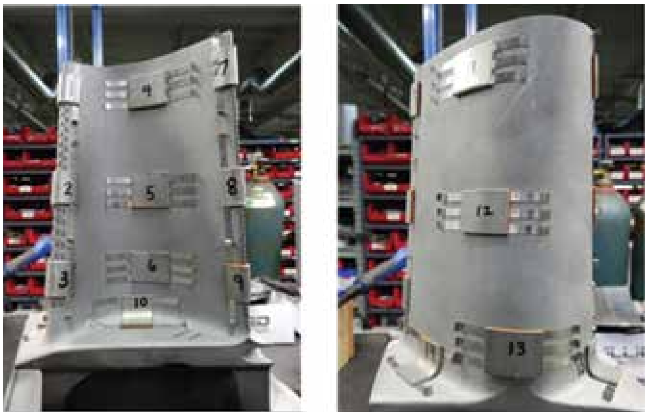


1. 7F.03 TBC-coated first-stage turbine buckets included the Rainbow Test program. The term "rainbow" derives from the color differences of the top coat

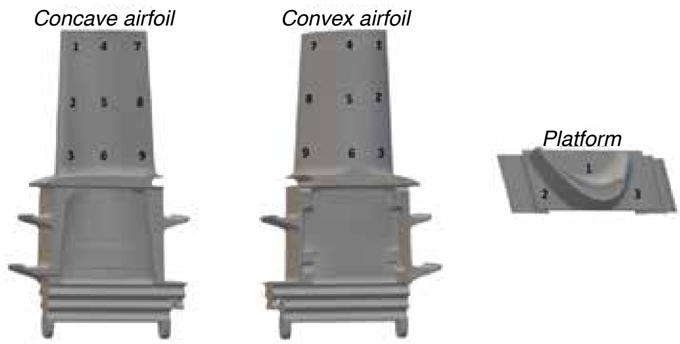
Company →	APG		Doosan		MD&A	Sulzer	CTS	Honeywell (H), Liburdi/H, PSM/H
Coating →	HDVC	RKHDVC	DTS115	DTS180	PWPS3001	HICoat XTR	CT1702	
TBC top coat								
Nom YSZ thick, mils	12	0	8-16	8-16	6 and 3	10-18	Dense 2-4 Porus 10-15	4-5
Nom YSZ thick, µm	300	0	200-400	200-400	150 and 75	250-460	Dense 50-100 Porus 255-280	100-125
Nom Low K thick, mils	NA	18	NA	NA	9	NA	5-10	10-15
Nom Low K thick, µm	NA	460	NA	NA	230	NA	125-250	250-380
TBC intermed (flash) coat								
Process	APS	APS	APS	APS	APS	APS	APS	APS
Classification	NiCrAlY	NiCrAlY	CoNiCrAlY	CoNiCrAlY	CoNiCrAlY	CoNiCrAlY	CoNiCrAlY	NiCrAlY
Nom thick, mils	3	3	1-3	1-3	3	0.5-2	2	1-3
Nom thick, µm	75	75	25-75	25-75	75	15-50	50	25-75
TBC bond coat								
Process	HVOF	HVOF	HVOF	HVOF	HVOF	HVOF	HVOF	HVOF
Classification	NiCrAlY	NiCrAlY	NiCrAlY	CoNiCrAlY	CoNiCrAlY	CoNiCrAlY	CoNiCrAlY	NiCrAlY
Nom thick, mils	9	9	4-8	4-8	8	4-6	8	4-10
Nom thick, µm	230	230	100-200	100-200	200	100-150	200	100-200

2. Air plasma spraying of a first-stage bucket

4. TBC top-coat spallation at this S1B's platform edge prior to installation



3. Use of tabs allow use of the same buckets in multiple trials



5. Top-coat thickness was checked at 21 locations on the S1B airfoils

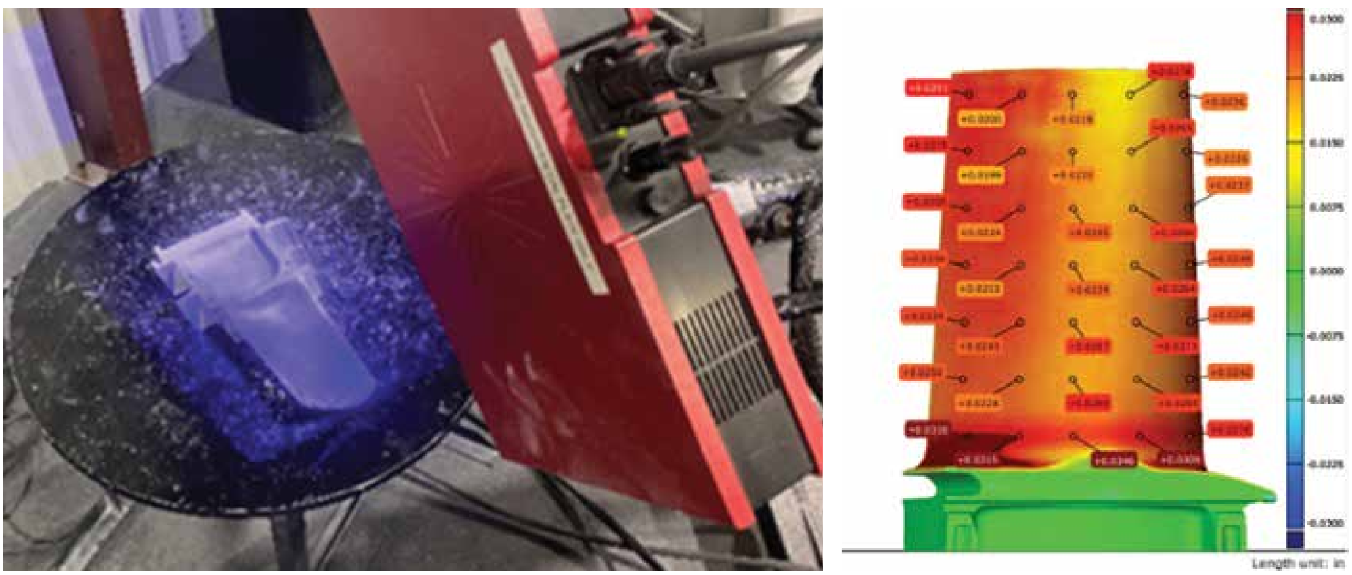
flash (air plasma spray, APS), and top (APS) coat was performed for thickness, interface contamination, porosity and oxidation, vertical and horizontal cracks, unmelted particles, oxide clusters, and other imperfections. Fig 3 shows that most coating providers opted to use tabs attached to the S1B so the same bucket could be used for several trials.

The optimum thermal-spray settings and robotic program for part preparation, robot location, and part manipulator; fixturing and programming of the robot coded; and coating parameters and heat treatments were documented to ensure these steps could be repeated for the actual parts. Inspection reports and metallurgical samples were made available to TEServices and Dominion for review and qualification based on the coating specifications outlined in TEServices' "7FA.03 Repair Specifications."

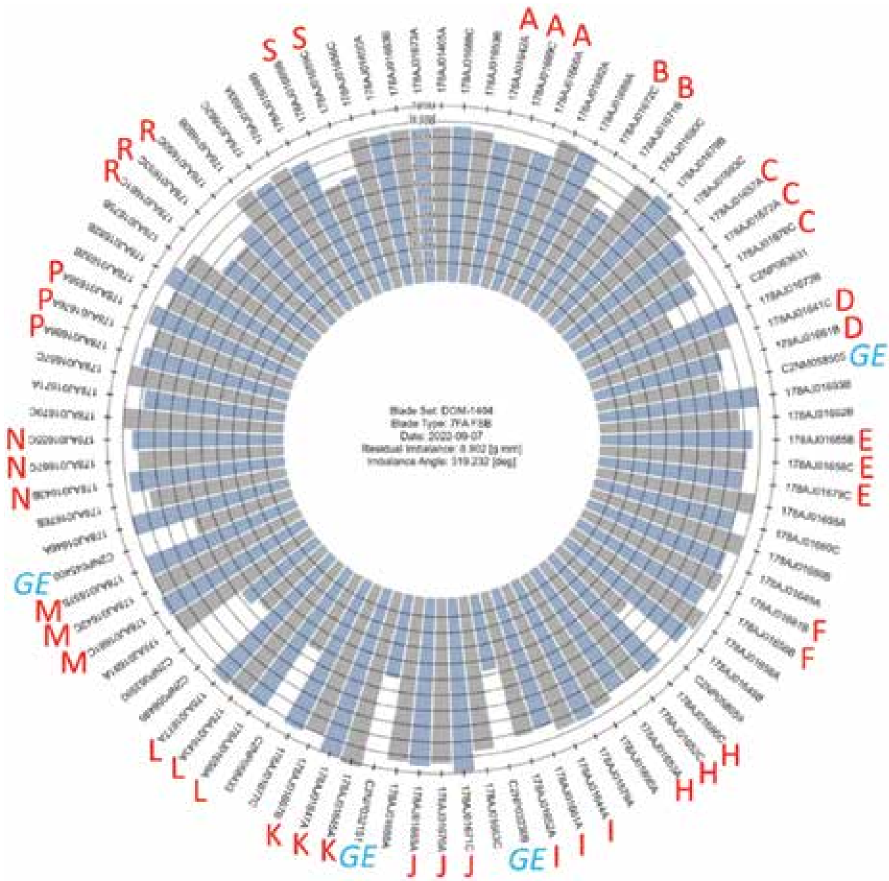
Proper coating application on the actual GT components should be verified before their installation to avoid premature coating failure and the need to remove affected components.

TEServices' verification included visual inspection, serial numbers, cooling-hole check, review of quality records including work scope, inspection reports with weight gain and ET thickness, and heat-treat charts. Visual inspection revealed three buckets with the same coating system as having spallation of the top coat at the edge of the active-side platform. The initial participant proposal was to flash coat these locations with a ceramic top coat and blend; however, after discussion with the coating participant, TEServices and Dominion decided to test these buckets as is (Fig 4).

Top-coat thickness was checked at 21 locations (Fig 5) using an eddy-current thickness gage to determine erosion and/or delamination of the top coat during operation. The average top-coat thickness of each



6. Blue scan of a first-stage bucket prior to TBC application (left); coating thickness measurements made by blue scan (right)



7. Moment chart of all 92 first-stage buckets, including the rainbow buckets (codes A through R minus B, F, and S)

coating system was between 8 and 22 mils (200 to 560 μm).

The S1Bs were blue-light scanned after stripping (Fig 6 left) and again after TBC application (Fig 6 right). The two scans were overlayed to determine the total (top, flash, and bond-coat) thickness based on the difference of dimensions in the airfoils.

This was valuable information for the coating participants, allowing them to modify their robotic programs for future sets of S1B to obtain a more uniform coating thickness. For the rainbow test, the value of this inspection comes after operation, to identify if delamination and/or erosion had occurred and if coating thickness was a contributor.

Post-coating operations, installation. Prior to their installation, test buckets were shipped to MD&A for another visual inspection, cooling-hole check, flow check, and moment weighing and sequencing with the rest of the set (Fig 7).

Air flow was less than before coating; however, all flows met the MD&A minimum requirement of 0.0300 in^2 effective area, except for two buckets. Both were just below the requirement and accepted after engineering review.

All first-stage buckets were moment weighed and the sequencing was performed in a manner that the buckets with the same coating were grouped together for borescope purposes. This resulted in somewhat higher-than-normal residual imbalance (nearly 8 gmm) but still within MD&A specs and accepted by Dominion.

In November 2022 this set was installed in Dominion's Chesterfield 7F.03 unit, which has a flared compressor and MNQC (steam injection) combustion system. Operation started the following month with these operating parameters: firing temperature, 2350F; steam load, 100,000 lb; and an estimated 800,000 lb/hr of air.

Test duration is five years; planned removal is fall 2027.

Semi-annual borescope inspections will be performed until removal of the first-stage buckets in 2027. The first borescope inspection was performed after 2000 hours in May 2023 by Advanced Turbine Support (Fig 8). The results of borescope inspections of all 92 first-stage buckets, including the repaired S1B with standard coating, are the following:

- No defects detected in 67 buckets.
- Leading-edge tip spallation in five buckets.
- Minor leading-edge cooling-hole spallation in one bucket.
- Severe leading-edge cooling-hole spallation in five buckets.
- Leading-edge and platform spallation in three buckets.
- Spallation of the leading-edge tip and mid cooling holes in three buckets.
- Color difference in three buckets.

The bottom line: TBC applied on all first-stage buckets was able to withstand the hydrogen environment for the first 2000 hours. Next year, following TBC Rainbow Test II, TEServices will report the halfway (2023-2025) borescope results. CCJ

Acknowledgement. This article is based on "Durability Test of Advanced TBCs," presented at ASME Turbo Expo 2024, held June 24-28, in London, England. Authors were Hans van Esch and Stijn Pietersen of TEServices, John Scheibel of EPRI, and Olaf Barth of Dominion Energy.

8. Coating loss at the platform edge is seen in the left-hand borescope photo; leading-edge tip coating loss and discoloration at the right

Software-as-a-service diagnostics underscores whole-of-plant approach

Metroscope, a relatively new entrant (2023 launch) to the US real-time powerplant process diagnostic software market, recently conducted a webinar to build more awareness of its technology and to differentiate it from other packages (some of which have been evolving since the early 1990s and can be considered "standard" in combined-cycle plants and in centralized M&D facilities serving multiple sites).

The webinar began with a technology primer, followed by four use cases (two narrated by a representative of TotalEnergies, the French energy company), a testimonial of sorts by Tetra Engineering, a well-known powerplant consulting firm, and a rather vibrant Q&A session.

The technology was initially applied by Electricite de France (EdF, the national electric utility) at nuclear plants in France. In 2018, the company began implementations at French combined-cycle facilities and quickly ramped up to "70+ plants and more than 450 users wordwide."

Metroscope distinguishes its offering with these general features: Software-as-a-service business model, a thermodynamics-drive (deterministic) approach versus probabilistic, and holistic, systems-based diagnostics. While the presenters explained that users don't need to add sensors in order to gain immediate value from the software, one expert did acknowledge that you'll get better results from those subsystems which are properly instrumented. "Systems with few instruments are more like black boxes," he said.

The technology presentation began with a typical situation, monitoring overload, faced by an operator (Fig 1) and the question: "Why are 10 sensor values trending mostly outside of their normal ranges?"

Like other diagnostic packages, Metroscope seeks to identify and correlate patterns in deviations from normal sensor values. However, the real advancement appears to be (1) the ability to map each sensor deviation, and patterns among them, to specific root causes; (2) indicate to staff the performance impact of a given issue or fault; and (3) suggest actions to address the fault. In other words, common faults (Fig 2), or actionable root causes, have an associated "signature" of sensor deviations.

To do this, a "digital twin" (a thermodynamic model of the plant calibrated to its expected healthy behavior) is paired with an "inference engine." The digital-twin outputs expected healthy behavior, while the sensor values over time indicate current behaviors. Symptoms, for example a steam leak, are detected. The inference engine analyzes the symptoms and then outputs diagnosed faults and their associated quantified impacts on performance (Fig 3).

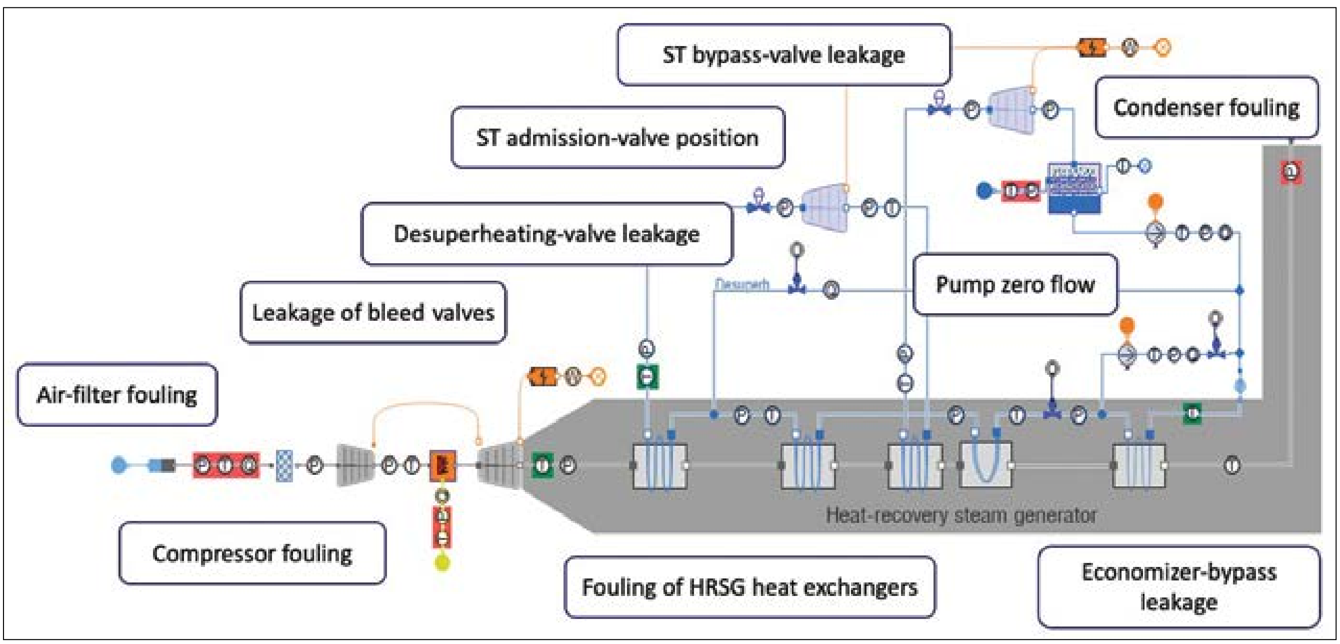
Joe Hachem, TotalEnergies, described a use case involving a 440-MW combined cycle with SGT5-4000F gas turbines and a triple-pressure HRSG. The software detected fluid loss somewhere in the IP steam-turbine subsystem, but plant staff had no idea where. It was hard to locate the loss because IP system purges and bypasses are not well instrumented.

The Metroscope "diagnostic plot" (showing the deviations), and the impacts on other subsystems (for example, the condenser), pointed to the IP drain valves. Many sensors were deviating together which ruled out faulty sensors. IP drain valve leakage was monitored for 10 months. What started as a small, persistent, but worsening leak, soon had a real impact on performance.

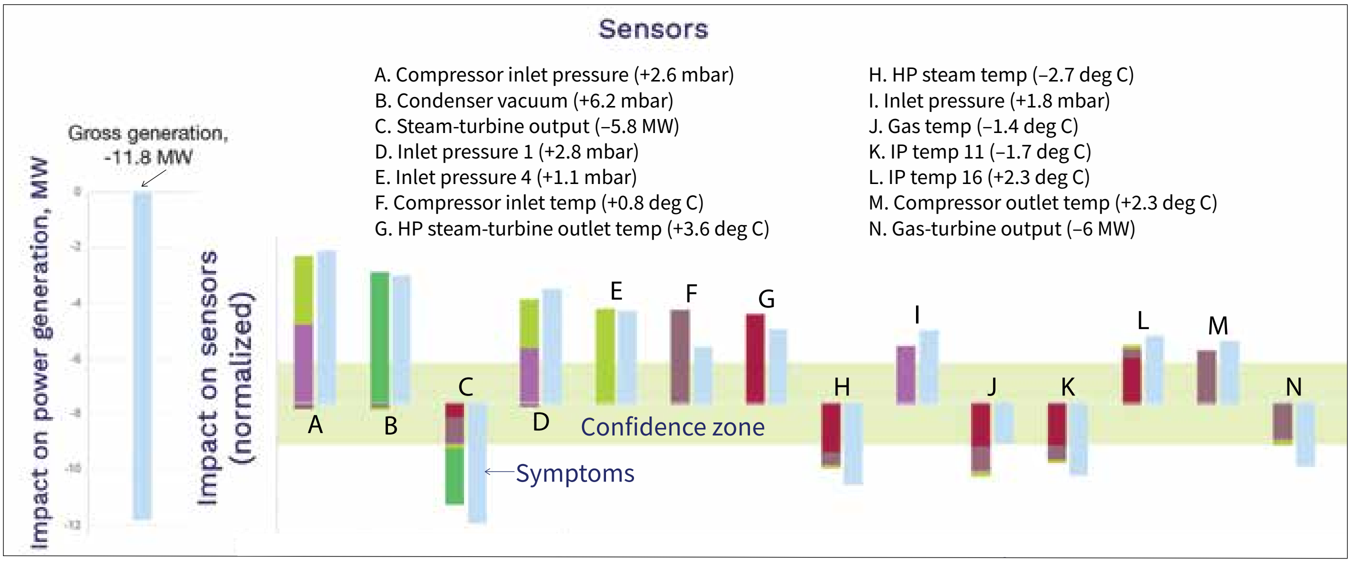
At the next outage, the drain valves, and others, were investigated and fixed; 3.8 MW of output was restored. In this case, Metroscope detected a loss early, allowing the plant staff to focus on, monitor, and address it at the appropriate time.

The second use case involved a 400-MW plant with Ansaldo V94.3A gas turbines, and a similar configuration as the first example. This time, the area of interest is the condenser. The unit experienced a sudden loss of condenser vacuum, up to 14 mBar, which occurred right after an outage, with an associated 3- to 4-MW loss in output.

The Metroscope diagnostic plot pointed to the vacuum pumps. A list of impacted subsystems also was provided. DCS data showed that two vacuum pumps were operating simultaneously. A check of the inlet filters showed that they were completely clogged and were cleaned the next day.



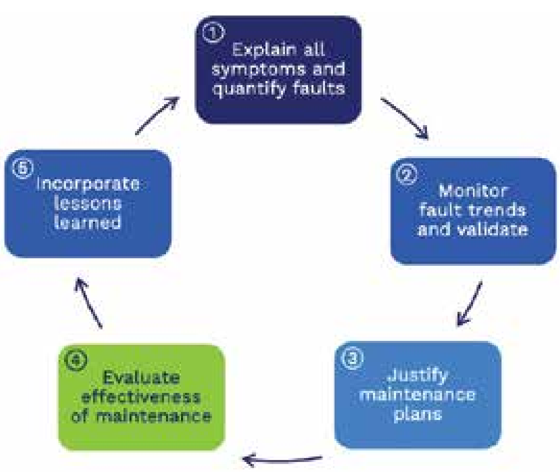
1. When 10 sensors are out of range simultaneously, diagnostic software helps operators assess root causes



2. Common faults are stored in the Metroscope fault library and customized to each unit resulting in tailored fault matrices. Current sensor readings are compared to their expected values from the digital twin (thermodynamic model) and the symptoms inferred from the readings are mapped to the fault matrix

In this case, the software indicated a problem that would have been difficult to detect, because of the lack of instrumentation (condensers are typically poorly instrumented, according to Hachem's slides), and allowed the plant to prioritize the pumps in their investigation.

Metroscope's Berenice Chanzy spoke on the next two use cases, one involving a compressor leak at a single-shaft, 9F-powered plant that was detected by the software. A close eye by plant staff on the issue showed that the performance impact had grown from a 4- to 10-MW loss after three months, with attendant increase in specific fuel consumption. A maintenance plan and outage, supported by the software's insight, was executed in Month Four during which staff repaired an endoscope plug and inlet-bleed-valve flange. This work immediately restored 4 MW.



3. Simultaneous out-of-range sensor readings are matched with symptoms to give a holistic explanation of the behavior at a given time stamp, along with the impact on performance. The fault diagnostics process begins with inference results. Reliability builds trust and faster action in Steps 2-4. The process ends with continuous-improvement feedback to incorporate changes in faults and models

The last use case centered on the steam system in the same plant and a leak around the steam turbine, suspected by the staff but which could not be identified and was not visible from the outside. One fault (among 20 occurring at the same time) signature involved 11 sensors, but primarily steam temperature. The software confirmed the leak; early validation allowed the plant to monitor the leakage until something could be done about it.

These use-case descriptions are abridged. Listen to the recorded presentation if you want to know more. Be sure to review the slides elaborating on the basic technology.

David Moelling, chief engineer, Tetra Engineering, focused on the "actionable" nature of the Metroscope software's suggestions and the early warning of issues costing money. "Earlier diagnostic systems [going back to the 1980s] involved too many instruments and hardware, not to mention staff resources," he said.

Moelling listed these four relatable value points in today's operating environment:

- Plant upgrades and life assessments. Diagnostics speed the setting of a baseline assessment for gas turbine and duct burner upgrades.
- Root-cause assessments. It is easier to determine the root cause of a failure with a diagnostic baseline.
- Freeze protection. Diagnostics help determine which instruments are being impacted by cold weather.

The Q&A session revealed some of the practical aspects of the software. For example, the software has to be calibrated, or trained, with several years of historical operating data, usually pulled from the PI archives. A typical deployment takes about six months, with a go-no go decision by the second month as to whether the software will provide value.

A user asking about the quality of the historical data elicited this response: "Make sure you have good data!" The software does have "some filtering strategies to deal with bad data." The TotalEnergies rep noted that some data-quality issues did crop up, leading them to recheck data quality at all the sites using the software. Most of the data were fine, but there were some bad values.

One attendee was concerned that some sensor settings are "related to constants in the control system rather than the thermodynamics." The response was that Metroscope "doesn't account for control logic, but rather the performance envelope and system effects," and that "the longer the data history used to calibrate the software, the better the issue detection and outcomes under a wide variety of boundary conditions."

Finally, with respect to the steam bypass system example, an attendee wondered why you would need the software to indicate a drain-valve issue when there may be two or more thermocouples with alarms in the control room already available to detect leakage. The response was that t/c values may be buried several screens deep to the operators and that the software also quantifies the leak and presents the performance impact. Also, the software may indicate adverse trends well ahead of alarm points. CCJ

Avoid Stellite delamination with alternative hardfacing

By Richard Laukam, ValvTechnologies LLC

Steam stop valves, located at the boiler outlet, provide isolation. These typically are wedge-type gate valves, stop-check valves, or parallel-slide gate valves. Hardfacing often is applied to the seat and closing member (wedge, plug, or discs) to reduce wear and extend the duration of leak-free service. Hardfacing is the building up of high-hardness, wear-resistant metal onto a surface, using a welding process.

For steam, Alloy 6 and Alloy 21 (developed under Kennametal's Stellite® brand) have been used extensively for hardfacing. Although Stellite® has been used successfully in a range of steam applications, the focus of this article is temperatures exceeding 1000F.

Widespread occurrences of failure in such cobalt-alloy hardfacings became evident after 2010. Valves manufactured from Grade 91 materials revealed subsurface cracking at the fusion line. Such interfacial cracking, also called "disbonding," "liberation," or "delamination," can propagate where sections of the hardfacing detach (photo). Chunks of Alloy 6 hardfacing material have been found in the perforated screen of strainers in steam turbines.

Scan the QR code nearby with your smartphone or tablet for a backgrounder on the electric-power industry's experience with hardfacing.

After cobalt-alloy delamination became widespread, many power stations reported similar findings discovered in ultrasonic tests (UT), across valves in service for as little as 10,000 hours, but mostly approaching 80,000 operating hours.

Consequences became so severe that the Electric Power Research Institute (EPRI) established a program to investigate cobalt-alloy disbonding. Findings are presented in the table.

EPRI's investigations focused on the metallurgical structure of the base metal and cobalt-alloy interface boundary layers. These boundary layers were found to contain a brittle intermetallic sigma phase, formed at the fusion line between the base metal and cobalt-alloy weld material.

This undesirable brittle phase forms over time during exposure to elevated temperature. Then during thermal cycling, cracks can initiate at these locations and propagate along the plane of the fusion line.

Keeping iron dilution below 10% and using a nickel-alloy 82 "butter" layer between the base metal and the cobalt-alloy hardfacing has been a big step forward. Time has shown this decelerates delamination but does not eliminate it completely.

Before reviewing technological advances, it is important to understand the basics. Engineers may ask for hardfacing, but what is really being asked for is a wear-resistant coating. Keep in mind the following:

- Hardness is a measure of a material's resistance to permanent deformation (scratching, wear, galling or bending).
- Wear resistance is a material's ability to resist material loss by mechanical action.
- Galling is the transfer of one material to another when the two are rubbed together.
- Toughness is a material's ability to absorb energy and deform elastically and plastically, without fracturing.

A cobalt-free hard surface applied by a High-Velocity Oxygen Fuel (HVOF) coating process revolutionized the aerospace industry in the 1980s. HVOF is a deposition of layers of powdered material using thermal and kinetic energy, applied to the base-metal substrate. Such applications were developed for turbine blades (oxidation and corrosion), actuators and flaps (sliding wear), landing-gear components (wear and corrosion), and hydraulic systems (corrosion and erosion).

Manufacturers like ValvTechnologies, inspired by the aeronautical challenges of modern flight, developed a compressive spray technique. HVOF avoids the brittle intermetallic sigma-phase formation discussed earlier, providing a reliable bond to the base metal.

Damage to steam-turbine blades attributed to disbonded Stellite

Structure, processing, and properties affect the performance of HVOF coatings. A hot, high-velocity gas jet sprays molten particles onto components. A mixture of powdered materials is forced through a spray-gun nozzle and ignited. The resulting

EPRI findings on cobalt-alloy disbonding

Not a specific:	Observed in:
Valve supplier	Several manufacturers used Stellite
Valve type	Gate valves and Y-pattern stop-check valves
Valve-body fabrication	Cast steel (WC9 and C12A) and forged steel (F91)

gas forms a circular flame surrounding the powder, as it exits the nozzle, for uniform heating, melting, and acceleration.

This fuel and oxygen mixture atomizes within the combustion arc, creating high velocities, propelling particles at near supersonic speeds and producing an exhaust jet traveling at six times supersonic speed. Such high velocities, uniform heating, and low dwell time are contributing factors for dense, tightly bonded coatings.

Manufacturing techniques play an important role. Surface preparation is essential; for a successful coating, the substrate must be grit-blasted to create a slightly rough surface (anchor pattern) to provide the optimal surface finish to which the inbound powder will adhere. The surface also must be clean and free from contamination that could otherwise fill the pits.

HVOF requires a line of sight in relation to the area to be coated. In some cases, angles other than 90 deg achieve that line of sight. Machining, or better yet, horizontal grinding, is crucial to achieve fine finishes with highly parallel flatness.

Several types of HVOF coatings exist. Selecting the right one for valves depends on temperature, erosion, and/or corrosion. A versatile and high-performance version created for high-temperature steam consists of 75% chromium carbide with a 25% nickel-chromium binder. The result, compared to weld hardfacing, is a much harder coating at elevated temperatures, and beneficial compressive residual stress.

Inspection of IsoTech® parallel-slide gate-valve components, after 10 years of cyclic service (2500 thermal cycles), proves that delamination is avoided, even with zero maintenance—an industry first for steam isolation valves. As the energy landscape evolves from baseload, to one of more frequent starts to complement renewables, combined-cycle powerplants are becoming more cyclic in nature. With significant thermal transients an emerging consequence, the criticality of selecting the best available hardfacing technology becomes clear.

Examples of 10-year-old components with chromium carbide coatings are intended to be forensically examined by EPRI, with any results likely to be published in 2025. It is hoped the expected outcome independently confirms that chromium-carbide coatings avoid delamination in high-temperature steam.

Given that more than half of the steam stop valves operating at over 1000F will experience disbonding within 100,000 operating hours, these advances in coating technology mean the industry can avoid financial consequences of damaged steam turbines, which can run into millions of dollars in repairs, and lost revenue. CCJ

About the author

Richard Laukam is a highly respected industry expert at ValvTechnologies. A graduate of England's Loughborough Univ with a Master of Engineering degree and a postgraduate certificate in management. Laukam is a member of the Institution of Engineering and Technology.

LEGACY TURBINE DOCTOR, NO. 2 IN A SERIES

Persistence key to finding gremlin impacting starting reliability

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

An MS7001B engine with Mark I Speedtronic™ controls failed to start reliably for about a year. Failure-to-start causes included loss of flame, trip at Complete Sequence to full-speed/no-load (FSNL), trip on 95% speed (14HS), TNH (high-pressure shaft speed) bog-down, and unknown. The troubleshooting effort was complicated by inconsistency in the different results recorded between starts. Because of the inconsistency of results on each start, the troubleshooting effort was directed at turbine hardware, the Mark I controls, and control wiring.

Using legacy troubleshooting techniques, the following hardware and systems were eliminated as the cause of the issue:

- Mark I trip logic, L4EC, and L4, which were forced to run for the start.
- Atomizing-air and compressor-bleed-valve function and potential leakage.
- The bleed valves were disabled and kept open during the start.
- Inlet-guide-vane actuation at 9.7 VCE (variable control electronics). The guide-vane actuator was disabled to keep the IGV closed. Note that VCE is an indicator of fuel-valve position, which determines fuel flow. This fuel valve is full-open at a VCE of 20 and closed at 0. Thus, a 9.7 VCE means the valve is about half-open.
- Fuel forwarding and fuel-pump-output pressure were monitored during the start.
- All of the Mark I cards were pulled and reinserted to eliminate pin corrosion.
- Control wiring from the Mark I to the fuel pump servo was replaced.
- Mark I cards from an operating sister unit were exchanged.
- The servo was not exchanged because the sister unit's servo was the only reliable servo available.

The following results were observed when implementing the various troubleshooting procedures:

- Operation is very sensitive to VCE changes: Startup to speed control caused a flame-out.
- Raise/lower results in immediate loss-of-flame trip.
- One-third of start attempts achieved FSNL.
- Raise/lower at FSNL resulted in a slow deceleration to 3500 rpm and then recovery to 3600 rpm.
- During one deceleration, the fuel valve was gagged at 6.7 VCE; however, the pump stroke continued to decline resulting in loss of flame.
- As the number of start attempts increased, the number of trips at 95% speed decreased.

The majority of trips occurred at 95% speed; 14HS and 3 Complete Sequence trips were identified as the consistent problem. Flame-out on unit deceleration had not caused a recent trip. Troubleshooting focused on the 14HS relays and wiring. There are eight 14HS relays and four 3 relays.

A set of "dummy" relays was made from three spare relays which were visually inspected and energized to confirm their electrical conformance to contact resistance and coil amperage. The dummies were used to replace the 14HS and 3 relays, one at a time, to check the effect of the relay coil and contacts on the decrease in turbine speed.

The Complete Sequence 3 relays were replaced with the dummy relay. It was noted that as a relay was energized, the speed would decrease from 3600 rpm and then recover to 3600 rpm. The turbine speed, servo voltage, RVDT, and VCE were monitored for changes during relay installation and raise/lower. The four 3 relays were replaced.

The 14HS, 14HS1, 14HS2, 14HX1, 2, 3, 4, and 5 relays were replaced one at a time, with the same drop in speed and recovery as with the 3 relays. The turbine speed, servo voltage, RVDT, and VCE were monitored for changes during relay installation and raise/lower. The turbine responded to raise/lower without a drop in speed.

Technicians checked and replaced 14HSY1 and 2 as well and restarted the unit. Response to raise/lower was better, 10 rpm compared to 30 rpm. The remaining seven 14HS relays were replaced.

At this point, reliable starts to Complete Sequence were being achieved; however, raise/lower was still a problem. The troubleshooting focus shifted from a problem in the relay logic causing a trip to a problem with energizing relays affecting the fuel-pump response.

An attempt to auto synchronize was not successful because turbine speed decreased and did not recover. There are a total of five load-selection 83LA relays (LA is the acronym for "load application.") The 83LA2, 3, 4, and 83LAX relays were replaced, one at a time, starting with 83LA2. The turbine speed, servo voltage, RVDT, and VCE were monitored for changes during relay installation and raise/lower. The stability and raise/lower response checked. Results were stable.

Auto synch was attempted. Setpoint was reduced and at 3600 rpm the unit synchronized and a speed increase initiated. Load then was increased to 8 MW. Next, baseload was selected and the unit was ramped to 44 MW at 925F exhaust temperature. IGV acti-

Speedtronic™ Mark I control systems were installed on gas turbines in the early 1970s, primarily on MS5001N and MS7001B engines vated at 9.9 VCE. A normal stop to shutdown followed.

A restart was initiated after a period on turning gear to demonstrate repeatability. After the unit achieved FSNL, auto synch was initiated and unit output increased to 6 MW, then to baseload (44 MW).

The unit was shut down and removed from forced-outage status.

Conclusions. As mentioned in the first paragraph, the subject unit had experienced starting problems for more than a year. The first troubleshooting effort determined that the fuel pump was not following the VCE signal and it was removed for overhaul, resulting in another three-month outage.

The major problem faced was the inconsistency of results on starts: Each start was different. The consistency of results improved as the number of starts increased.

The "breakthrough" was determining that the energizing of individual relays affect unit stability, usually a deceleration to loss of flame. The second conclusion was that the more relays energized, the more often the unit would trip on loss of flame. Troubleshooting shifted from looking for a relay or wiring trip to relays affecting the servo current.

Reliable starts were achieved by replacing individual relays in the 3, 14HS, and 83LA circuits. In the case of the 3 relays, four individual relays were involved. For the 14HS, there were eight and for the 82LA five. The initial troubleshooting effort focused on the 14HS relays because the most common trip was at 95% speed.

Root cause. The relays had become "sticky" during the year of inactivity in a salt-air environment and required an increase in amperage to pick them up. The increase in amperage affected the P28-Vdc power supply to the servo drive card and the milliamp output to the servo. The reduction in milliamps to the servo caused turbine deceleration and loss-of-flame trip. One of the best indications of this problem was that during one deceleration, VCE was gagged at 6.7 but the pump stroke continued to decline, resulting in loss of flame.

The P 28-Vdc power supply has both over-voltage and over-current "crowbar" protection. If amperage exceeds the limit, the current output is limited. The P28-Vdc voltage will remain at 28 Vdc because the current output is limited. In hindsight, the current output of the P28-Vdc power supply should have been monitored.

The unit started reliably after the mentioned adjustments were made. The corrective action recommended was to exercise the unit at least every two weeks. CCJ

Editor's note: For more insight on troubleshooting early Speedtronic™ control systems, scan the QR code.

How exhaust-gas distribution can affect SCR performance

By Vaughn Watson, Vector Systems Inc

The efficiency and long-term performance of an SCR depends largely on several key design considerations regarding various system components. When complex NOx reductions on combined cycles are required, there are critical values related to the fluid distribution in the system which must be addressed to ensure success.

While the SCR catalyst often gets all the credit, *and all the blame when performance declines*, careful study of catalyst design, and of the entire system, can alleviate or prevent many of the top factors that contribute to SCR issues.

SCR system performance is largely dictated by ensuring adequate distribution of the exhaust gas to meet the catalyst volumetric sizing.

The distribution metrics typically are the following:

- Velocity (at the catalyst face), ±15% RMS.
- Temperature, ±25 deg F.
- NH_3/NOx, ±10% RMS.

SCR catalyst design itself is crucial to the effectiveness of the emissions control system. Catalyst volume, formulation, and pressure drop, must consider the totality of operating scenarios the combined cycle unit will encounter. This evaluation should include each load level the combined cycle unit will operate within and consider all ambient conditions expected as well the fuels burned. Consideration of multiple fuels and blended fuel streams is especially important.

Your evaluation must include all operating cases from the combined-cycle OEM, plus interpolation of existing plant DCS data trends. Don't overlook unit turndown: It too must be evaluated because the NOx produced typically is higher at lower loads, and the decrease in exhaust temperature will limit SCR catalyst efficiency.

Stratification and speciation of the NOx also are important. Ideally, the NO/NO_2 ratio should be 50% or less NO. Additional testing to ascertain the NO/NO_2 speciation may be necessary because a high NO_2 speciation can be a major issue for SCR efficiency and require specific catalyst formulations to achieve NOx reductions.

Catalyst bypass can greatly affect NOx reduction and ammonia slip. Bypass *must* be limited to less than 1%. The catalyst support structure and perimeter seals should be inspected during outages for any areas that may have exhaust-gas and ammonia bypass. Catalyst modules must be well packed to ensure no ammoniated exhaust gas is flowing unreacted through gaps around the catalyst bed. On a high-performance SCR, small amounts of bypass can drastically add up to the inability to meet emissions limits.

Ammonia distribution within the exhaust gas cross-section is a huge factor in the catalyst's ability to properly reduce NOx levels (Figs 1 and 2). This important part of the system largely falls to the design of the ammonia injection grid (AIG). It must consider both the amount of ammonia and diluent required to inject and mix with the NOx present in the exhaust gas.

1, 2. Ammonia distribution piping to the AIG is shown at left. Control zones should be able to adjust ammonia in sections of the ductwork. Photo, right, illustrates traverse tuning which involves taking measurements of ammonia distribution at each of the eight AIG elevations. The more zones, the better the tuning capability

Careful consideration of injection pressures, mass flow, and density change along the length of each AIG lance are essential for proper distribution and mixing. AIG design for advanced NOx control must consider orifice size, spacing, and angle of injection necessary to ensure the proper distribution. This is critical to ensuring the NH_3:NOx distribution is matched to the volume of SCR catalyst.

SCR catalyst and the AIG should be inspected during every outage to ensure there is no significant plugging, which can have a major effect on SCR performance by impacting ammonia distribution. Recall that catalyst fouling masks the active pore sites on the catalyst substrate. If you find plugging, eliminate it immediately and determine the root cause. Finally, remember that AIG design can be improved for better distribution and performance, and help provide significant resilience against frequent plugging issues.

Ammonia purity. Specifying the correct purity grade of ammonia is critical. For aqueous systems, reagent-grade ammonia is the best option. The key differentiation lies with the purity of the water in the solution. Avoid water with soluble minerals that can plug, foul, erode, and damage SCR equipment. Such impurities can lead to vaporizer fouling, AIG plugging, and potential catalyst performance problems. It only takes one bad load of reagent to experience the headaches associated with ammonia impurity.

Backpressure effects on distribution. Velocity profiles are critical for SCR catalyst performance, and all catalyst guarantees have a velocity-profile requirement associated with the SCR design. Ductwork often does not have sufficient pressure drop through the components in the gas path to "flatten" this profile. The result is high velocities in the center and excessive stack emissions. In today's world of emission requirements (2 ppm NOx and 2 ppm ammonia slip) the effects of not having sufficient backpressure become very evident.

In some of the advanced SCR catalyst designs being implemented, there is insufficient backpressure to promote the degree of mixing required. In many cases, an existing AIG cannot adequately distribute and mix the ammonia and NOx with the reduced backpressure of a modern catalyst.

SCR and CO catalysts typically operate at 25% to 40% below their manufacturer-guaranteed pressure-drop numbers, at least early in their lives. In recent years, suppliers have developed an ultra-low-pressure-drop module design. These are good for retrofits into existing sites, but recent experience suggests new installations may suffer if these components are not applied properly. Even designs based on CFD models of gas-side flow can miss the mark by as much as 30% to 40% based on field measurements.

Recently, the author had the opportunity to examine two units at a site that had just replaced its SCR catalyst. Unit 2 was failing emission guarantees right after changing its catalyst. By contrast, Unit 1 was running better on a 13-year-old catalyst than Unit 2 with the new catalyst.

Site personnel blamed the catalyst vendor. However, it was clear after evaluating the operating data, that while the site was saving almost 2.2 in. H_2O of backpressure on the gas turbine, the new catalyst had changed the flow distribution through the SCR. The AIG was marginal back in the day, but the backpressure of the old catalyst was flattening the flow and allowing for adequate mixing. Redesign of the AIG and a relatively simple retrofit has the site back up and running with a highly efficient SCR system. Both pressure drop and ammonia consumption have been reduced.

End note: By ensuring the design factors discussed above are considered in your SCR and ammonia systems, and addressing problems when they are discovered, you'll have an efficient SCR system capable of advanced NOx reduction. CCJ

HRSG need not be a limiting factor in GT upgrade

By Vignesh Bala, Vogt Power

Editor's note: This is the second of three articles exploring the impacts of gas-turbine upgrades on heat-recovery steam generators. It focuses on "re-rating" of the HRSG after the upgrade to extract maximum benefit from the work. Part 1, which examined the driving factors behind GT upgrades, appeared last issue (CCJ No. 79). Part 3, next issue, will address implementing HRSG mods onsite and the associated planning considerations.

Goal of the series is to make your plant more economical and efficient while gaining flexibility to adapt to changes in load demand.

Gas-turbine upgrade packages can vary significantly in terms of the benefits. Most OEMs and third-party providers offer several tiers of upgrades and modes of operation within each tier. The higher-tier packages often come with sizable increases in peak performance accompanied by greater changes in exhaust-gas flows and temperatures. Upgrade tiers are designed to fit the operator's requirements considering load demand, operational needs, and budget.

Conventional approach. Historically, managing significant increases in exhaust-gas flows and temperatures was straightforward, although not the most accurate approach. A thermal model of the HRSG was created using original design data, and new GT upgrade conditions were input into the model. Then you calculated new steam pressures using a KN factor relationship. It assumed the steam turbine was a constant-volume device, allowing for approximations based on new steam flows and temperatures.

Subsequently, the new operating pressures and temperatures of all HRSG pressure parts were computed. Increases in operating pressures were only a concern if they exceeded the weeping tolerance of safety relief valves, as defined by the ASME Boiler and Pressure Vessel Code (sidebar).

If the new operating cases were infringing on the weeping tolerance of the safety relief valves, this would not be permissible. If the condition persisted when supplemental firing was used, a burner runback would be recommended. If it was happening in an unfired condition, then a GT runback would be recommended such that the maximum operating pressures were just below the weeping-tolerance pressure of the valves. While this conventional approach complies with the Code and design practices, it limits the plant's ability to fully benefit from a gas-turbine upgrade. For example, GT or burner runbacks reduce the plant's overall capacity.

Today, the engineering and design capabilities are available to accommodate these constraints and maximize plant performance.

New approach to HRSG re-rates

Re-rating an HRSG to realize the full potential of a GT upgrade is not a straightforward process. Certain high-pressure (HP) components can be re-rated while others will perhaps require replacement. This process starts with a study to identify the system and component limitations.

Thermal analysis. The process of re-rating HRSG systems or components starts with a detailed thermal analysis. New exhaust-gas flows and temperatures from the GT upgrade are input into the HRSG model and the KN factor relationship is used to obtain the new design pressures for all HRSG pressure parts. All systems having a new design pressure higher than the existing pressure are identified. Since the thermal analysis is used to determine the new design pressures of the components, it is critical that the maximum performance conditions and other factors—such as steam augmentation, power augmentation, inlet chilling, etc—are considered and modeled.

Mechanical analysis. Once the updated design pressures for the systems are established, mechanical code calculations must be performed on each component. This includes all tubes, headers, end plates, drums, piping, branch connections, valves, thermowells, and welds.

Keep in mind that major pressure parts sometimes pass the mechanical calculations but attachment welds do not. For example, in a recent re-rate by Vogt Power, the drum shell and head passed Code calculations under the new pressures, but the nozzle welds did not and required reinforcement weld pads (Fig 1).

Weeping tolerance of safety relief valves

The most common cause of a pressure relief valve failing to open at the set pressure is the accumulation of corrosive deposits between the valve disc and seat. According to the 2019 edition of the ASME Boiler and Pressure Vessel Code, paragraph 103.1.3 (p 41), this usually happens when the pressure relief valve "weeps" or leaks slightly.

To help overcome this condition, the system operating pressure should be lower than the set pressure of the relief valve, with minimum differentials recommended as follows:

Boiler design pressure, psig	Min differential as a percentage of boiler design pressure
Over 15 to 300	10% but not less than 7 psi
Over 300 to 1000	7% but not less than 30 psi
Over 1000 to 2000	5% but not less than 70 psi
Over 2000	Designers judgment (Vogt uses 5%)

1. Nozzle welds may require reinforcement

2. Drain pots and drum internals must be analyzed

The mechanical analysis must follow the most recent Code year, because legacy codes and stress values cannot be used. This is particularly important for Grade 91 components, as allowable stress values have been reduced significantly in recent years.

Miscellaneous components. Following current codes instead of legacy codes when re-rating systems has broader impacts. For example, plants built in the early 2000s, and earlier, typically had a 2-in. drain pot downstream of the attemperator spray piping.

However, the latest pressurized (P) HRSG Code requires drain pots to be one nominal pipe size smaller than the piping they are installed in, up to a drain-pot size of 12 in. Therefore, if the HP steam or RH systems are being re-rated, new and larger drain pots must be installed to comply with PHRSG requirements.

Additionally, the safety valves of the re-rated systems must be replaced or have their springs reset to match the new system pressure. Capacity of the safety valves also must be considered because higher steam flows dictated the re-rate.

Similarly, the steam separation capacity of the drum internals must be verified to ensure there is no increased risk of moisture carryover from the drums (Fig 2).

Other re-rating considerations. The mechanical Code calculations described above form the foundation of the re-rating process. These calculations assume that the components are new and clean. However, plants that have been in operation for several decades may experience degradation of their pressure parts.

Therefore, additional due diligence is necessary to ensure these components are suitable for use at higher pressures. Since clear rules regarding this have not yet been established, it is crucial to involve the State Authorized Inspector, and the R-stamp holder performing the re-rate, early in the process.

In a recent project, the following due-diligence process was used by Vogt Power:

1. Make mechanical Code calculations showing the components pass under the new pressures based on new and clean condition.
2. Ultrasonically test components to quantify degradation from new-and-clean conditions and verify their current state. The testing should be performed on a representative sample of tubes, piping, elbows, and branch connections. Locations that are likely to experience degradation (such as regions prone to flow-accelerated corrosion) are selected for testing.
3. Build a pipe stress model and run it on the components being re-rated.
4. Assure 100% NDE of all new field welds.
5. Conduct a field hydrotest at 80% of the new maximum allowable working pressure.

Conclusion. This article focused on the considerations for an HRSG system during the re-rate process. In Part 1, the author suggested involving HRSG engineers early in GT upgrade planning for best results. Each plant will offer unique challenges to overcome; however, your HRSG does not have to be a limiting factor during a GT upgrade. The third and final article in this series will discuss onsite planning considerations, as well as best practices during the construction phase of the upgrade. CCJ

About the author

Vignesh Bala is VP HRSG Services at Vogt Power, a Babcock Power Inc company. He leads a group providing cutting-edge analysis and retrofit solutions for combined-cycle powerplants to increase capacity and reliability in support of a changing power market. Bala and his team conduct studies, inspections, and turnkey retrofits, and provide parts for HRSGs manufactured by all OEMs.

2025 CONFERENCE PLANNER

January 27-30
PSM Asset Managers Conference
Annual Conference and Exhibition, Wyndham Grand Jupiter at Harbourside Place, Jupiter, Fla. Details/registration at www.psm.com.

February 9-14
501F Users Group
Annual Meeting, Loews Ventana Canyon Resort, Tucson, Ariz. Details/registration at www.501fusers.org as they become available. Chairman: Ivan Kush, Cogentrix Energy Power Management.
Contact: Jacki Bennis, jacki@somp.co.

February 9-14
501G Users Group
Annual Meeting, Loews Ventana Canyon Resort, Tucson, Ariz. Meeting is co-located with the 501F Users Group conference. Details/registration at www.501fusers.org as they become available. Chairman: Jody Lumpkin, plant manager, Hillabee Generating Station, Constellation Energy. Contact: Jacki Bennis, jacki@somp.co.

March 18-20
FT8 Users Group
Second Annual Meeting, EPRI Campus, Charlotte, NC. Details/registration at www.FT8users.com as they become available. Contact: Ashley Potts, ft8@ft8users.com.

March 30-April 2
Western Turbine Users Inc
35th Anniversary Conference and Expo, Long Beach, Calif, Long Beach Convention Center. Details/registration at www.wtui.com first week of January. President: Ed Jackson, Missouri River Energy Services. Contacts: Charlene Raaker, conference registration coordinator, craaker@wtui.com; Wayne Kawamoto, conference executive director, wkawamoto@wtui.com.

May 19-23
7F Users Group
2025 Conference and Vendor Fair, Sheraton Birmingham Hotel and BJCC, Birmingham, Ala. Details/registration at https://www.powerusers.org as they become available. Contact: Sheila Vashi, planning.team@sv-events.net.

May 15-17
European HRSG Forum (EHF)
11th International Conference, Prato, Italy (about 20 minutes by car or train from Florence), Monash University. Details/registration at https://europeanHRSGforum.com. Chairman: Barry Dooley, Structural Integrity Associates (UK).
Contact: Rachel Washington, rachel@meccaconcepts.com.au.

June 16-19
Legacy Turbine Users Group
Third Annual Conference and Vendor Fair. The Frame 5, 6B, and 7EA Users Groups comprise LTUG and meet independently; some joint functions, including meals and vendor fair. Details/registration at https://www.powerusers.org as they become available. Contact: Sheila Vashi, planning.team@sv-events.net.

Late June
AOG (Alstom Owners Group) Users Conference
Eighth Annual Meeting. Details/registration at https://aogusers.com. Contact: Ashley Potts, ashley@aogusers.com.

2025 CONFERENCE PLANNER

July 21-24
HRSG Forum
2025 Conference and Vendor Fair, The Woodlands Waterway Marriott Hotel, The Woodlands, Tex. Details/registration at https://www.powerusers.org as they become available. Chairman: Bob Anderson, Competitive Power Resources. Contact: Sheila Vashi, planning.team@sv-events.net.

August 4-7
HA Users Group
Eighth Annual Meeting. Details/registration at https://www.powerusers.org as they become available. Contact: Sheila Vashi, planning.team@sv-events.net.

August 25-28
Combined Cycle Users Group
2025 Conference and Vendor Fair. Meeting is co-located with the Steam Turbine, Generator, and Power Plant Controls Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, planning.team@sv-events.net.

August 25-28
Steam Turbine Users Group
2025 Conference and Vendor Fair. Meeting is co-located with the Combined Cycle, Generator, and Power Plant Controls Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, planning.team@sv-events.net.

August 25-28
Generator Users Group
2025 Conference and Vendor Fair. Meeting is co-located with the Steam Turbine, Combined Cycle, and Power Plant Controls Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, planning.team@sv-events.net.

August 25-28
Power Plant Controls Users Group
2025 Conference and Vendor Fair. Meeting is co-located with the Steam Turbine, Generator, and Combined Cycle Users Groups, and the Low Carbon Peer Group; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact: Sheila Vashi, planning.team@sv-events.net.

August 25-28
Low Carbon Peer Group
2025 Conference and Vendor Fair. Meeting is co-located with the Steam Turbine, Generator, Combined Cycle, and Power Plant Controls Users Groups; some joint functions, including meals and vendor fair. Details/registration at www.powerusers.org as they become available. Contact Sheila Vashi, planning.team@sv-events.net.

September 23-25
HRSG Forum América Latina
First Annual Conference, Blue Tree Premium Hotel, Morumbi, São Paulo, Brasil. Details/registration at hrsgamericalatina.com as they become available. Contact Scott Schwieger, scott@ccj-online.com.

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