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User Group Reports

Features

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2014 Conference and Vendor Fair
February 16 - 20
The Westin Mission Hills Resort & Spa
Rancho Mirage, Calif
Contact: Caren Genovese, carengenovese@charter.net
More information, p 95

24th Annual Conference and Exposition
March 23 – 26, 2014
Renaissance Hotel/ Palm Springs Convention Center
Palm Springs, Calif
Contact: Charlene Raaker, raaker.charlene@prodigy.net
More information, p 80

Spring Conference & Trade Show
April 6 - 10, 2014
PGA National Resort & Spa
Palm Beach Gardens, Fla
Contact: Wickey Elmo, info@ctotf.org
More information, pp 79, 125

2014 Conference and Vendor Fair
May 19 – 23
Sheraton Wild Horse Pass Resort & Spa
Phoenix, Ariz
Contact: Sheila Vashi, sheila.vashi@7Fusers.org
More information, p 106

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

FROM THE EDITOR

2014 User Group Meetings

February 5-6, 501D5-D5A Users, Mid-Year Meeting, Orlando, Fla, Details as they become available at www.501d5-d5ausers.org. Participation in this forum is at no cost to owner/operators of 501D5-D5A gas turbines. To register, email Gabe Fleck, chairman, gfleck@aeci.org.

February 16-20, 501F Users Group, Annual Meeting, Rancho Mirage, Calif, The Westin Mission Hills Resort & Spa. Chairman: Russ Snyder, russ.snyder@cleco.com. Contact: Caren Genovese, meeting coordinator, carengenovese@charter.net.

February 16-20, 501G Users Group, Annual Meeting, Rancho Mirage, Calif, The Westin Mission Hills Resort & Spa. Meeting is co-located with 501F Users Group; some joint functions, including the vendor fair. Chairman: Steve Bates, steven.bates@suezenergyna.com. Contact: Caren Genovese, meeting coordinator, carengenovese@charter.net.

February 24-26, HRSG User's Group, 22nd Annual Conference & Expo, Las Vegas, Nev, Red Rock Resort & Spa. Visit www.hrsgusers.org for the latest information.

March 23-26, Western Turbine Users Inc, 24th Annual Conference & Exhibition, Palm Springs, Calif, Renaissance Hotel/Palm Springs Convention Center. Chairman: Chuck Casey, ccasey@riversideca.gov. Visit www.wtui.com for the latest information.

April 6-10, CTOTF—Combustion Turbine Operations Technical Forum, Spring Conference & Trade Show, PGA National Resort & Spa, Palm Beach Gardens, Fla. Contact: Wickey Elmo, group and conference coordinator, info@ctotf.org.

May 19-23, 7F Users Group, 2014 Conference & Vendor Fair, Phoenix, Ariz, Sheraton Wild Horse Pass Resort & Spa. Contact: Sheila Vashi, 7F operations manager, sheila.vashi@7Fusers.org.

June 3-6, 501D5-D5A Users, Annual Conference & Vendor Fair. Details as they become available at www.501d5-d5ausers.org. Contact: Gabe Fleck, chairman, gfleck@aeci.org.

Week of June 9, T3000 Users Group, 2014 Meeting and OEM mini courses, Alpharetta, Ga; venue to be determined. Contact: Neal Coffey, chairman, neal.coffey@gdfsuezna.com.

June 17-19, V Users Group, Annual Conference, Boston (venue to be decided). Contact: Dawn McCarter, conference coordinator, dawn.mccarter@siemens.com.

June 23-26, Frame 6 Users Group, Annual Conference & Vendor Fair, Ft Myers, Fla, Sanibel Harbour Marriott Resort & Spa. Program details as they become available at www.Frame6UsersGroup.org. Contact: Wickey Elmo, conference coordinator, wickelmo@carolina.rr.com.

July 27-31, Ovation Users' Group, 27th Annual Conference, Pittsburgh, Westin Convention Center Hotel. Register for membership (end users of Ovation and WDPF systems only) at www.ovationusers.com and follow website for details as they become available.

August 5-7, Southwest Chemistry Workshop, San Diego, Wyndham San Diego Bayside. Host: Atlantic Power Corp. Contact: Frank Spencer, water specialist, Applied Energy LLC, fspencer@atlanticpower.com.

August 11-13, Combined Cycle Users Group, 2014 Conference and Discussion Forum, San Antonio, Westin Riverwalk. Registration and program details at www.ccusers.org as they become available. Registration/sponsorship contact: Sheila Vashi, sv.eventmgt@gmail.com. Speaker/program contact: Dr Robert Mayfield, rmayfield@tenaska.com.

September 7-11, CTOTF—Combustion Turbine Operations Technical Forum, Fall Conference & Trade Show, San Diego, Calif, Rancho Bernardo Inn. Contact: Wickey Elmo, group and conference coordinator, info@ctotf.org.

Early fall, ACC Users Group, Sixth Annual Conference, San Diego. Details as they become available at www.acc-usersgroup.org. Registration/sponsorship contact: Sheila Vashi, sv.eventmgt@gmail.com. Speaker/program contact: Dr Andrew Howell, chairman, andy.howell@xcelenergy.com.

Early fall, 7EA Users Group, Annual Conference and Exhibition. Details as they become available at http://ge7ea.users-groups.com. Contact: Pat Myers, pcmyers@aep.com.

December 9-11, Australasian HRSG Users Group, 2014 Annual Conference, Brisbane, Australia, Brisbane Convention and Exhibition Centre. Registration and program details as they become available at www.ahug.co.nz. Registration/exhibitor contact: Kirsten Pain, meetings@tmm.com.au. Speaker/program contact: Dr Barry Dooley, chairman, bdooley@structint.com.

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HRSG, valve issues addressed; M&D added to GTs, transformers

1. Walter M Higgins Generating Station, a 2 x 1 combined cycle owned by NV Energy, is powered by 501FD2 gas turbines

NV Energy had the luxury of time for the first gas-turbine major inspection at its Walter M Higgins Generating Station, located in Primm, Nev, near the California border about 40 miles southwest of Las Vegas (Fig 1). With demand still down from pre-recession levels, the company conducted the outage when temperatures were moderate, from February to May, thereby avoiding the overtime and premium services normally associated with a major. This was the only GT major conducted by the utility in 2013.

Higgins is a 2 × 1 combined cycle powered by 501FD2 gas turbines from Siemens Energy Inc. The air-cooled plant began commercial operation in 1Q/2004 as Bighorn Generating Station, then owned by Reliant Energy Inc. Higgins has compiled some enviable statistics over the years, most recently 100% starting reliability in 2012: 131 starts in as many attempts.

Higgins

The outage involved work on the gas turbines, steam turbine, heat-recovery steam generators (HRSGs), high-energy piping, air-cooled condensers, SCR and oxidation catalyst beds, battery banks, critical instrumentation, etc. The editors participated in a roundtable discussion with several NV Energy engineers who played a significant role in the various projects conducted—including Josh Langdon, Jimmy Daghlian, Christian Herrera, Scott Amos, and Alex Fitzgerrells. Goal was to gather information for the following outage profile, which focuses on the inspections conducted, corrective action taken, and improvements made.

Gas turbines

A major concern of the utility's engineers was the integrity of compressor thru bolts, which had failed on two units in the 501F fleet during 2012. Removal of the rotor, as required for the major inspection, exposed the forward ends of the 12 bolts and nuts between the second and third compressor stages (Fig 2), facilitating the recommended UT inspection. Siemens inspected each rotor (about a day per unit) and found no indications.

501F thru bolt

PSM, which was conducting the GT overhaul as the third-party LTSA provider, in conjunction with inspection experts from Advanced Turbine Support LLC, provided a second opinion on bolt health. They identified two indications on one unit; however, those anomalies were smaller than the minimum size of concern established by Siemens.

Turbine Row 1 and 2 ring segments and blades had slightly more than 24,000 equivalent service hours and were replaced with like components manufactured by PSM. There were no major findings in Rows 3 and 4, but "heavy" repairs were required to correct for creep. R3 vane deflection, a fleet issue, also was addressed.

The No. 1 bearing on each unit was rebabbitted to correct for general wiping. There also was uniform wear of the thrust bearing but no scoring. It too was rebabbitted. A check of the exhaust section revealed wear and tear similar to that experienced by others. There was some cracking on the diffuser and that was weld-repaired after reassembly of the exhaust case. Engineers said that the plant's proactive preventive maintenance program for the exhaust section has been effective in minimizing the need for major repairs. Struts were in acceptable condition and no bearing drop was in evidence.

Combustion section hardware—fuel nozzles, transition pieces, baskets, support housing—had been replaced in January 2012 with PSM 12K components and they were in good condition.

A white deposit was found on flow-path components from the compressor inlet through to the turbine section. This was caused by a process upset in the evap cooler that allowed off-spec makeup into the unit for about 24 hours. The fouled media was replaced and a root-cause-analysis (RCA) investigation was being conducted at the time of the editors' visit to Higgins to assure this would not happen again.

NV Energy installed PSM's Combustion Autotune System on one of the Higgins GTs to automatically optimize combustion dynamics and emissions, holding both within specified limits while compensating for variations in ambient conditions, fuel-gas com-

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position, and engine deterioration. This eliminates the need for seasonal tuning. This is the first application of Autotune on a 501F series engine. It is installed and is meeting expectations on several GE 7FAs—including units with Mark V, Ve, VI, and VIe control systems. One of the immediate benefits of the system was a reduction in ammonia consumption for NO_x control.

Heat-recovery steam generators

NV Energy has invested in training staff engineers over the last several years to conduct HRSG inspections in-house. Attendance at the HRST Inc's HRSG Academy and participation in inspections conducted by outside experts have underpinned staff education. The utility's engineers are well versed in where to look and what to look for during inspections. Plus, they have access to prior inspection reports, so they know going into a given unit what the previous issues were and where to pay special attention.

The Higgins HRSG inspection was conducted by two engineers and took a full seven days. Tools of the trade: flashlights, mirrors, wire brushes, etc. Contractors were called in when a second opinion was necessary or special nondestructive examination (NDE) was required. The inspectors checked penthouse, vestibules, HP/IP/LP drums, stack, etc, looking for loose components (such as chevron steam separators), indications on belly pans, checking oxide colors in drums, cracking in downcomer welds, etc.

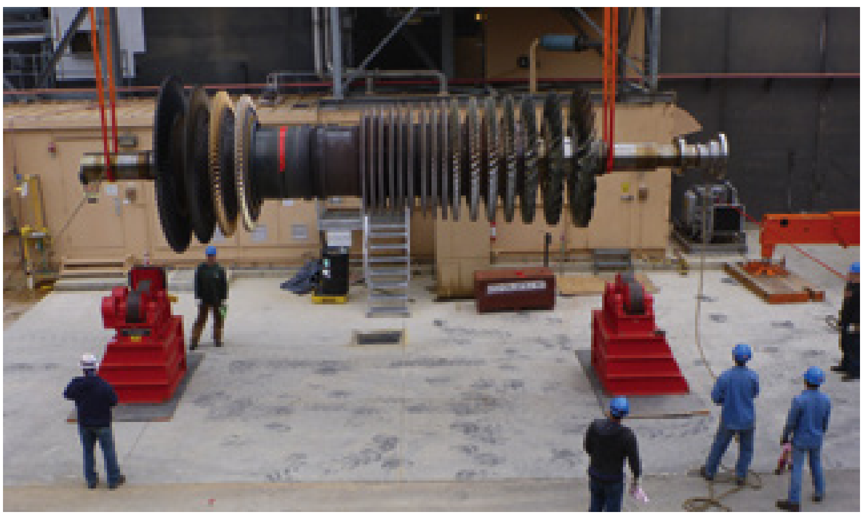
Indications were found in downcomer welds and Structural Integrity Associates (SIA) was called in; their inspectors found no cracking. A borescope used to inspect downcomers and risers on the LP evap section identified minor flow-accelerated corrosion at bends. It wasn't a serious condition; merely tracking. The lower IP and LP headers, made of carbon steel, showed no trace of FAC.

Some indications were found on the HP economizer and HP evaporator at the lower header-to-tube joints. NDE follow-up gave no cause for concern. Some tube rows were inspected full-length. Impact damage between bumpers and scallop bars were corrected by repositioning the bumpers with a slight offset. To protect the tubes against scallop-bar rub wear, sleeves were installed on tubes where the scallop bars are located. The traditional industry fix of welding together two hemispherical tube shields was used.

Some superheater tube rows immediately downstream of the duct burners revealed overheating damage: The metal decarburized and failed. SIA checked hardness and microstructure of tubes (T91, 1.5 in. diam, 200 mils minimum wall) in the region of interest and recommended replacement of 94. A lot of science went into the analysis and decision-making to hold costs in check. Original tubes were cut out leaving stubs in the top and bottom headers and new tube material was welded to those stubs. Welds were checked using linear phased array. Utility engineers surmised that the metal damage was caused by overfiring in periods of peak demand before NV Energy bought the plant.

Visual inspection of socket welds in HP economizer drains revealed the likelihood of improper fit-up and poor weld quality. More than 100 welds were repaired. A squeeze hydro was planned the week before restart to check for leaks and allow use of the same water for plant restart.

The reheat-steam attemperator installed at Higgins was not equipped with a liner, which is standard in all plants built by the utility. By contrast, the HP superheater attemperators had liners. The spool pieces for the reheat-steam attemperators, about 10 ft long ×18 in. diam, were replaced with ones having liners. A metallurgical assessment revealed welds, pipe, and headers downstream of the spool pieces were in satisfactory condition.



2. The rotor for one of Higgins' gas turbines is prepared for inspection of thru bolts

Valves

The roundtable discussion moved from HRSGs to large steam valves. It focused on stellite liberation from high-pressure (HP) and hot reheat (HRH) valves serving in F-class combined cycles. Tight shutoff of parallel-slide gate and non-return globe valves has been compromised in some cases. This is an industry-wide problem and something NV Energy is dealing with at Higgins and other plants. The company's experience was factored into the industry roundup published in 1Q/2013.

Stellite disbonding in valves

Generators

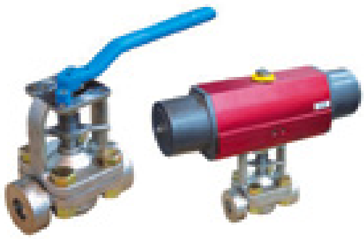
The Higgins gas turbines are coupled to Siemens Aeropac totally enclosed water-to-air cooled (TEWAC) generators, each rated 209 MVA at 18 kVand 0.85 power factor. A borescope inspection was conducted during the major to look for possible spark erosion. This was the second such inspection since a full rewind in March 2010 to verify that the new ripple-style slot filler had eliminated the spark erosion experienced with the original windings.

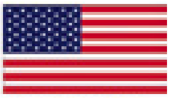
NV Energy engineers pointed out that not all available ripple fillers are capable of operation at the temperatures expected in the Higgins machines, nor are all capable of applying the force required given the available space in the slot. The ripple fillers installed in 2010 were specifically qualified for use in the Aeropac machine.

The straight portions of the coils in the slots were inspected using an articulating borescope through the radial vent slots in the core, from the outer diameter. Two rings of vent slots were inspected, one on the turbine end and one on the collector end. One half ring also was inspected in the top center of the core.

The inspection revealed no indications consistent with the appearance of spark erosion or partial discharge. Slot images were reviewed by the engineering department, which confirmed the conclusions drawn by inspectors. Validation of the rewind solution means no additional borescope inspections are required.

ST generator. A diagnostic inspection with rotor in-situ (DIRIS) was con-





3. Transformers for the Higgins gas turbines were equipped with a system for online dissolved gas analysis

ducted on the Alstom hydrogen-cooled generator for the steam turbine, rated 391 MVA at 21 kV and 0.85 power factor. This robotic inspection focused on stator wedge tightness and core integrity. In addition, the generator inspection program included review of the complete machine and its auxiliary systems, rotor-winding condition, stator/rotor winding polarization index, leakage-current HV testing, and a low-flux iron stator core test.

Inspection/test results met expectations. The slot wedge assessment met OEM criteria, the low-flux core iron test revealed no critical interlamination shorts, and no specific rotor winding issues were detected. Additionally, modal/impact testing was performed on the end windings. That effort indicated the elliptical (N=2) mode shapes of both baskets remained "low tuned"—below the 120-Hz excitation frequency. Thus there will be no vibratory amplification of the elliptical (N=2) ring modes. End-winding vibration is consistent with a 30-yr generator lifetime.

Local response testing showed that the local end-turn response amplitudes were below the acceptance criteria (less than 0.05 g/lb) with no concern about local independent resonances. Testing of the phase leads also revealed all responses were below 0.05 g/lb and no concern regarding local independent resonances.

Vibration of the generator frame and foundation are of continuing concern but the implementation of mitigation procedures has reduced the significance of the issue. Example: Vibration-induced instrumentation problems of the past generally have been eliminated. Vibration was conducive to the cracking of some external pipes, but they have been fixed and their support systems improved.

Loosening of internal fasteners was identified; problem solved by replacing conventional washers with Nord-Lock washers. The OEM told plant personnel the only way to eliminate any lingering vibration problems is to replace the generator, which it has done on two of the four units equipped with the same generator installed at Higgins.

Transformers

Higgins invested in a dissolved gas monitor for its transformers to help detect impending fault conditions and prevent lengthy forced outages (Fig 3). DGA, or dissolved gas analysis, is considered the single most powerful tool for transformer fault detection and asset management.

An eight-gas (H_2, CO, CO_2, O_2, methane, ethane, ethylene, acetylene) online DGA monitoring unit from Kelman Ltd was installed during the outage. It relies on advanced photo-acoustic technology to measure all significant fault gases, plus moisture in oil, without need for carrier or calibration gas. Data from the gas analysis go to the plant DCS (TXP) and are stored in PI on a 1-sec basis.

The plant also installed Doble Engineering Co's online intelligent diagnostic device (IDD) to continually monitor bushings and current transformers (CTs). The system detects abnormalities in the insulation system and, when appropriate, issues alerts—both locally and remotely. This keeps asset managers informed about the status of their bushings and provides the lead time necessary to determine appropriate corrective action, if necessary.

When IDD identifies abnormal bushing behavior it analyzes leakage current and assesses the condition of the insulation system. More specifically, IDD calculates the absolute and rate-of-change of power/dissipation factor and capacitance of the problem bushing, enabling it to determine the severity of the problem. Advanced signal processing and field-proven algorithms are designed to eliminate noise effects and other environmental conditions conducive to incorrect diagnosis and inappropriate corrective action. CCJ

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Steam can flow backwards, erode *trailing edges* of last-stage blades

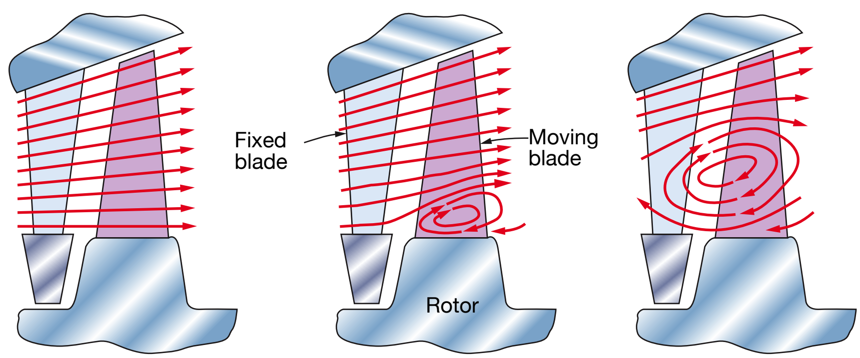
Steam turbines (ST) often exhibit leading-edge erosion on the last-stage blades (LSB) of the low-pressure (LP) section. This is from moisture forming as steam condenses prior to passing through the entire machine. The micron-size water droplets impinge on rotating-blade surfaces and remove material—mostly from the leading edge. It is a well-known problem and has been an engineering challenge for both OEMs and equipment owners since about the time condensing steam turbines were introduced more than a century ago.

Combined-cycle steam turbines often operate at part load, introducing a new problem to the LSB row: Erosion of the *trailing edge* (TE). Brent Gregory and Ryan Yamane of Creative Power Solutions (CPS), Fountain Hills (Phoenix), Ariz, told the editors they are seeing cases where a flow condition, developed in the ST itself, has caused TE erosion of LSBs. While last-stage steam-flow behavior at partial load may be well understood by turbine OEMs, that may not be the case for condenser manufacturers, which play significant roles in determining ST discharge conditions.

Integration of the ST with the condenser must be fully understood to maximize pressure recovery in the diffuser, allowing for optimal flow behavior. Gregory said recent work performed by CPS explains, in part, how wet steam in the condenser can re-enter the ST by being "pulled" into the LSB from a massive flow recirculation caused by turbine and condenser architecture.

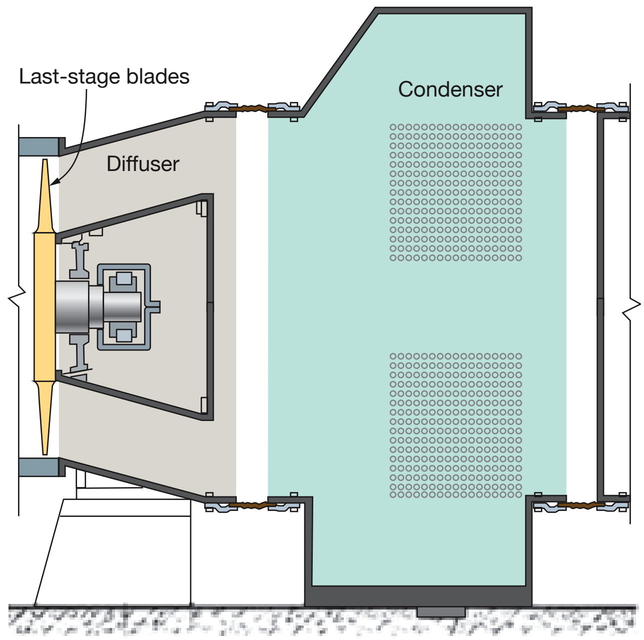
Gregory first saw the problem while designing LP turbines for aircraft engines. Turbine designers in that industry sector have a particular problem when designing blade rows because the LPT has significant swings in its operating point, depending on what the pilot is requesting as the engine duty—that is, take-off, cruise, taxi, etc. Each duty demands a different air flow requirement on the fan; hence, the LPT does not have a set design point.

Usually, efficiency is optimized for the cruise condition because the airplane will spend a significant amount of time there. What may happen under such scaled designs is the flow in the turbine may not have sufficient capacity to fill the annulus and flow will migrate off the hub or inner walls of the flow path, due to the centrifugal forces overtaking the momentum of the air flow, and be forced to the tip or outer walls.



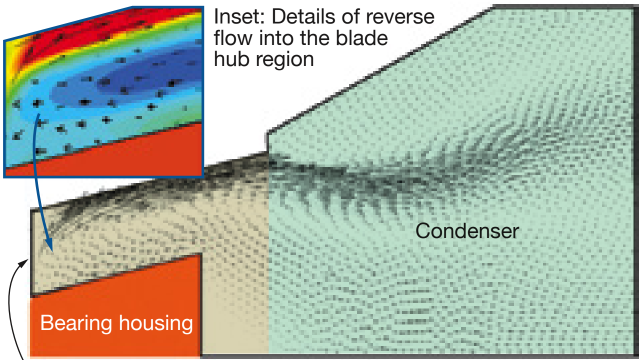
Turbine and Auxiliaries, J Jung Module 234-1

1. Simplified steam flow patterns in the last stage of a steam turbine at various loads

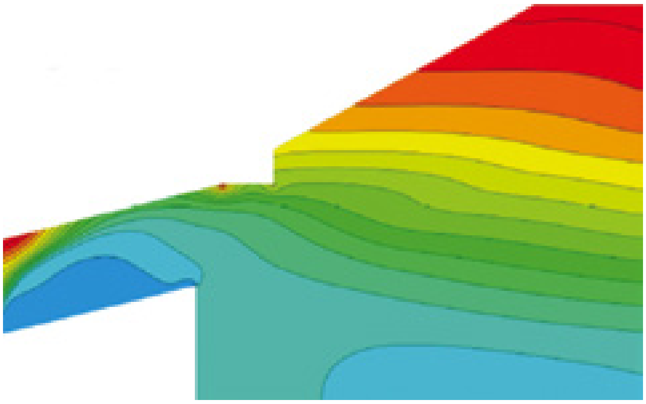


2. Typical arrangement of the steam-turbine last-stage blade row, diffuser, and condenser

Something similar happens in STs at no-load flow conditions or when steam flow is reduced to reduce shaft power output. The ST, which is designed for base-load operation, experiences a flow separation at part load inside the turbine flow path which extends downstream (Fig 1). The void



3. Vector plots show multiple large recirculation zones during reduced power operation. The recirc zone in the diffuser section carries wet steam back into the turbine



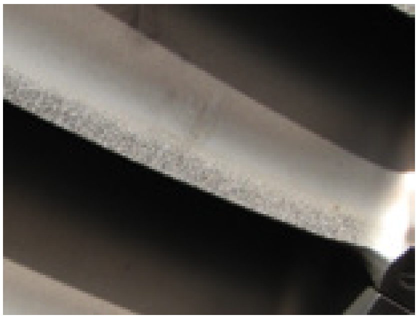
4. Static pressure contours illustrate a radial pressure gradient in the diffuser, instead of axial

that forms in the turbine extends into the downstream hardware and impacts the performance and endurance of the last few stages of the LP turbine.

In aircraft engines, advanced design techniques within the blade rows can be applied to prevent this phenomenon. In principle, the same technology could be applied to the last ST stage, but to Gregory's knowledge it has not been done. Another solution is required.

While wet steam may be the main culprit for TE erosion, Gregory and Yamane pointed to multiple sources of water droplets in water-cooled combined cycles capable of exacerbating the erosion mechanism. Examples:

- Exhaust-hood sprays, designed to keep the exhaust diffuser and expansion joint from overheating, inject water into the steam flow immediately downstream of the LSBs.
- Curtain-water spray systems for quenching high-enthalpy bypass steam introduced to the condenser during startup, shutdown, and/or GT blending in combined cycles with multiple engines.
- Droplets, which may have small diameters at injection, impinge on condenser supports and other parts, coalescing into larger droplets that can be drawn back towards the LSBs and contribute to TE erosion.



5. Trailing edge erosion of last-stage blades occurs at low loads

The diffuser directing turbine steam to the condenser also is designed to operate at one condition. Because there are no variable pieces of hardware in the flow path to accommodate the changing conditions of turbine flow at partial load, the diffuser also is operating in a sub-optimal way. This degrades turbine performance and may even cause structural damage.

Gregory said CPS recently had the opportunity to review such a setup with a customer. The arrangement was of typical turbine/diffuser/condenser architecture, similar to that in Fig 2. Extensive CFD was performed, with the OEM design team providing accurate turbine conditions at the plane of the turbine discharge.

The CFD model accurately predicted condenser and diffuser performance. Recirculating eddies caused by the large separation of flow off the inner diffuser wall and again off the back side of the bearing housing enabled wet steam to flow *upstream* and re-enter the turbine in the zone of separation. This can be seen in the CFD analysis as reflected in Fig 3 (velocity vector) and Fig 4 (pressure).

Thus reverse-flow recirculation carries wet steam from the condenser into the last-stage blade row, causing severe TE erosion on the suction side of the blade. The damage illustrated in Fig 5 is typical and eventually leads to separation of the blade.

Gregory offered several recommendations on how to limit the phenomenon's impact. Most obvious, he told the editors, is to run the turbine at its continuous full-load rating. At that condition, LSB TE erosion is unlikely. If the turbine must operate regularly at part load, he suggested regular inspection of the LSBs for erosion and of the water injection systems mentioned earlier to verify their proper operation. Regarding the latter, it is important to see that all nozzles are in place and in good condition and there is sufficient supply pressure to assure proper droplet atomization.

CPS engineers have found that, in some cases, damage occurs during unit starts and may become visible after a particularly busy production season involving daily starts. If you find erosion during a LSB condition assessment consider conducting a root-cause analysis because erosion will likely get worse with part-load operation. Perhaps only a change in operating procedures will deliver the desired result.

As the interview concluded, Gregory said that CPS has formulated unique solutions that could potentially address the erosion issue for certain turbine back-end configurations. The upgrades, he continued, are competitive with the costs associated with periodic replacement of LSBs to guard against the possibility of a catastrophic blade failure and the significant financial impact of an unscheduled outage. CCJ

Frame 5N rotor better than new after EOL inspection, repairs

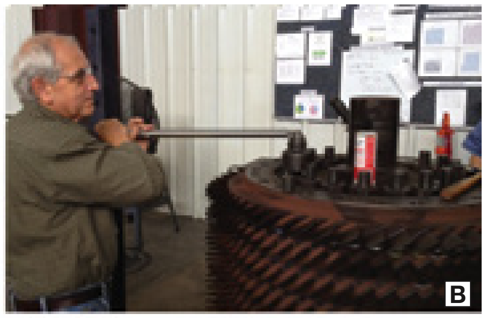
Gas-turbine rotors have a finite lifetime. For GE frames, Technical Information Letter (TIL) 1576 mandates an end-of-life (EOL) inspection for safety reasons after 200,000 factored hours of operation or 5000 factored starts, whichever comes first. A user attending the CTOTF™ Fall Conference, September 8-12, in Coeur d'Alene, Idaho, recently had completed an EOL inspection on a Frame 5N rotor with more than 5000 starts at the Dresser-Rand Turbine Technology Services (D-R) shop in Houston and offered to share that experience with colleagues through CCJ ONsite.

Many owner/operators of legacy GE engines—such as Frame 5s, 6Bs, and 7B-EAs—will be planning and conducting lifetime evaluations in the next couple of years, but may be unsure about how to prepare for an EOL inspection. They also may be unfamiliar with the various shop activities associated with such an important overhaul. This article offers some perspective.

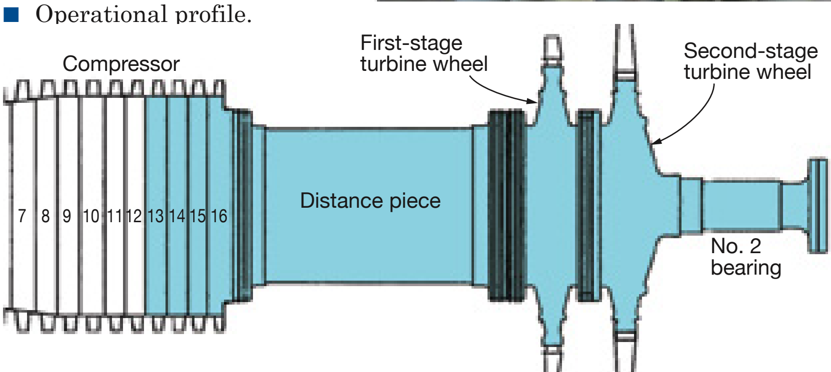
Additionally, some users remain skeptical regarding the need for an EOL inspection, having listened to several colleagues at user-group meetings discuss how their units were disassembled, inspected, and reassembled with no findings. But in the case profiled here, a significant crack was found in the first-stage turbine wheel, verifying the positive value of the process.

Rotor experts, such as D-R Engineering Manager Greg Snyder, can predict with reasonable accuracy what they would expect to find during EOL inspection based on information extracted from plant records. It is in your best interest to make PI and other data available to the shop selected well in advance of the inspection to facilitate planning and decision-making. These data include the following:

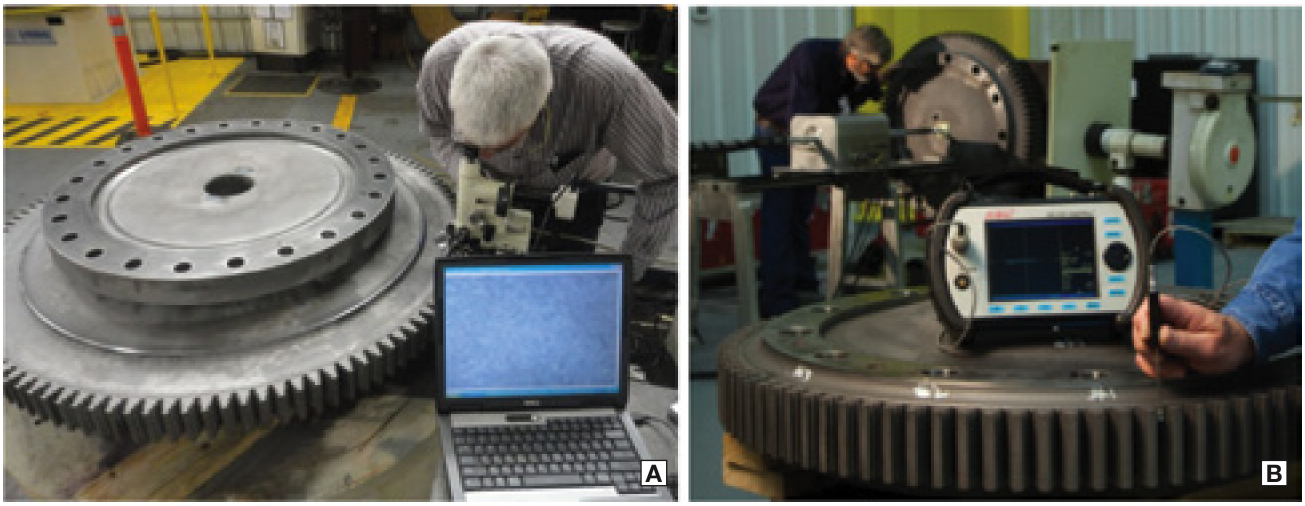
- Location (ambient conditions).
- Operating hours at base load and partial load.
- Number of starts: fast, normal, slow.
- Number of trips/load rejections.
- Ramp rates.
- Shutdown times between restarts.
- Control parameter time-history data.
- Fuel type.
- Operational profile.

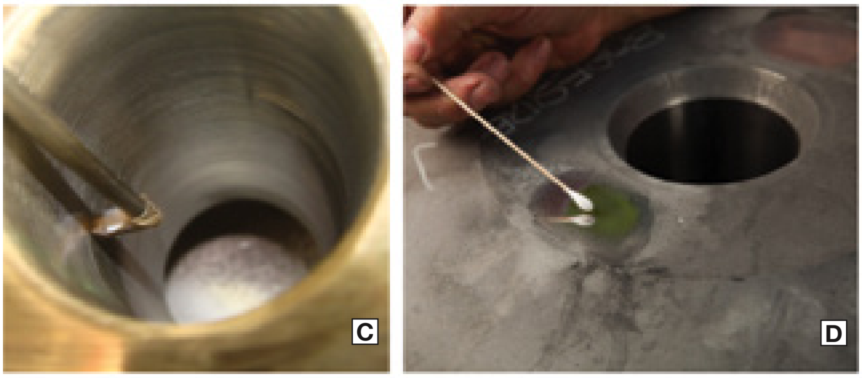


1. Incoming inspection and disassembly are the first steps in your rotor's shop experience. Balance, runout, dimensional, and NDE inspections are conducted before the rotor is lifted into the vertical position (A) and disassembled (B, C)



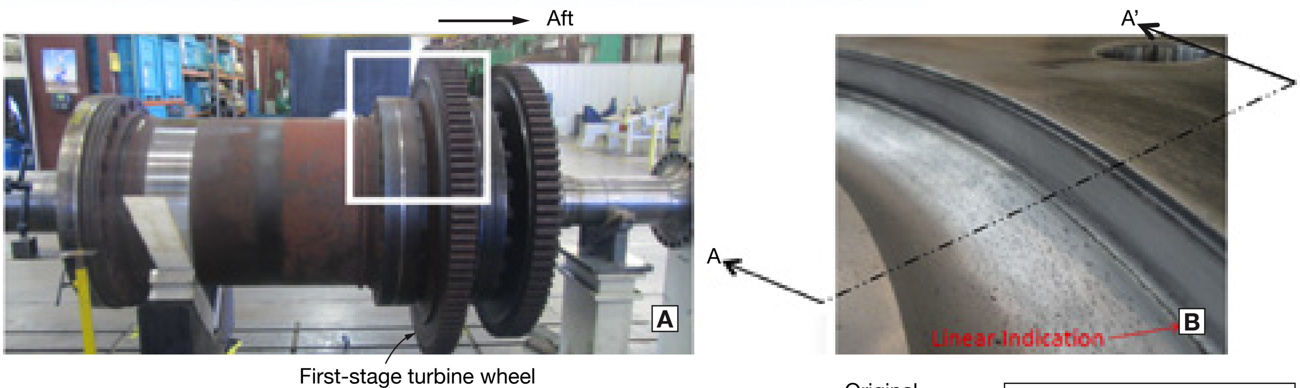
2. Focus of NDE and the metallurgical analysis are the high-temperature components: both turbine discs and the last four wheels of the compressor. Note that the Frame 5 "Nancy" has an R0 row in the compressor, so the wheels evaluated for this engine are equivalent to stages 14 through 17 of a Frame 7E

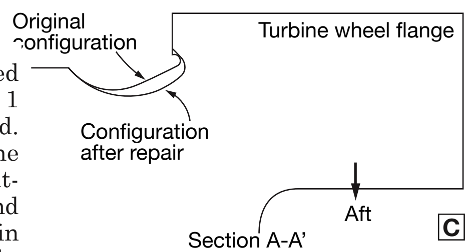




3. Advanced inspections include volumetric UT, eddy-current, fluorescent magnetic particle, etc (A-C), plus metallurgical evaluation (D)

4. Unexpected finding: The first-stage turbine wheel (A) had a 180-deg circumferential indication (B) that was corrected by removing some material to eliminate the crack (C)





- Maintenance history and previous inspection findings.
- Upgrades and parts replacements since COD.

The 5N rotor shipped to D-R by the owner had an interesting history. It was assembled in 1970; TIL 471, issued later, advised of potential "forging discontinuities" created during manufacture of the first- and second-stage turbine wheels. While no indications were found—or at least reported—during manufacture, UT reports from 1981 and 1984 each identified three indications in the first-stage wheel. Experts believed these were "birth defects," the accept/reject defect size used during manufacture likely being larger than the indications found during the 1980s inspections.

As part of the major outage in summer 1981, the rotor was shipped to a GE shop for grinding of the No. 1 journal; the rotor was not unstacked. Details of the three indications in the first-stage wheel found via straight- and angle-beam UT were archived and the OEM recommend re-inspection in four years or 500 fired starts, whichever came first.

During a combustion inspection in September 1984, three indications were in evidence once again. However, one of the 1981 indications was not found and the OEM chalked that up to a reporting error. The new third indication was identified with straight-beam UT. One of the remaining two indications was reported as having grown but obviously was still of minor concern because GE extended the interval for re-inspection to six years or 1200 fired starts, whichever came first.

A boresonic UT inspection performed in accordance with TIL 471-C, conducted during a hot-gas-path outage in September 1990, revealed no indications.

Discrepancies such as those described above should not come as a surprise for several reasons, including these:

- Wheel and disc design and inspection

tools of the 1970s and 1980s were rudimentary by today's standards.

- The type and critical size of indications for acceptance/rejection of rotor components following manufacture were not as well understood as they are now.
- Data archiving typically was manual.
- People make mistakes, especially inspectors when inexperienced and not properly trained. Regarding this point, users should be sure to check the qualifications of all technicians performing inspections on their rotors, monitor the inspection process, work closely with shop engineering personnel in the evaluation of inspection results, and participate in the repair/replace decision-making process.

After your rotor arrives at the shop, it will be inspected and then disassembled (Fig 1). A standard inspection of the assembled rotor (Fig 2) includes balance, run-out, and dimensional checks, and nondestructive examination (NDE). The owner said the nuts came right off the through-bolts during disassembly, which is not always the case.

Detailed inspections of high-temperature rotor components—including all turbine discs and the last four compressor wheels—using advanced NDE methods are conducted after disassembly (Fig 3). The sensitivity of the tools and techniques used provides increased confidence that there are no "visible" issues with individual rotor components. Such higher-order inspections also provide a baseline assessment for comparison during future inspections. They include the following:

- Volumetric UT using phased-array probe technology, advanced 3-D signal processing, and archiving of digital data.
- Eddy current.
- Fluorecent magnetic particle.
- Visual.
- Dimensional.
- Metallurgical evaluation.
- Hardness measurement.

Note that inspection of wheel dovetails (Fig 3B) requires removal of compressor blades and turbine buckets. The former effectively are destroyed in the process, so consider ordering new blades well in advance of the shop visit to gain an advantage in negotiations. In this case, the owner ordered new compressor blades but chose to use its spare set of turbine buckets. The compressor blades were later coated in the shop to protect against corrosion.

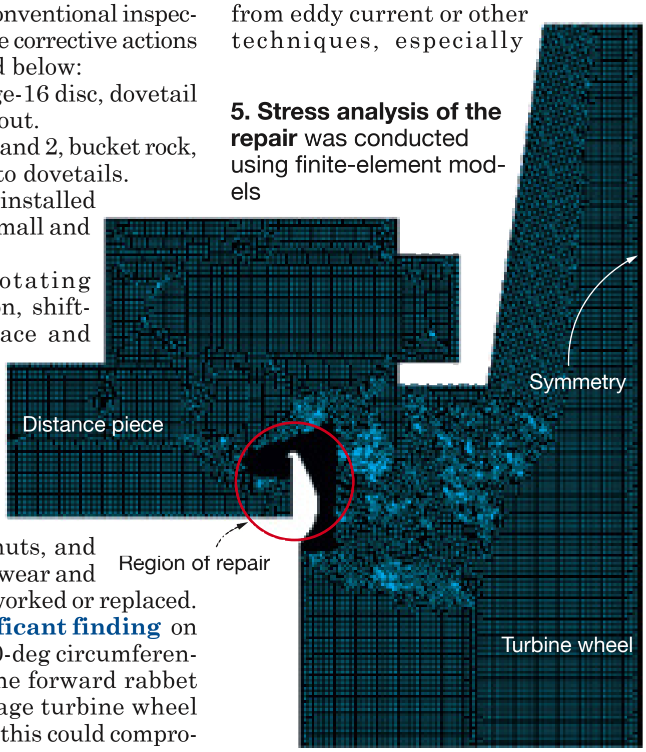
Rotor evaluation next. Inspection findings were reviewed and interpreted by an experienced engineering staff. This is one of the most important steps in the overhaul. Action taken on issues identified typically is one of the following: retire, repair, rejuvenate, and accept as is. Engineering assessments and detailed analyses guide repair and rejuvenation processes.

Areas of concern on the Frame 5N rotor identified by conventional inspection methods and the corrective actions taken are described below:

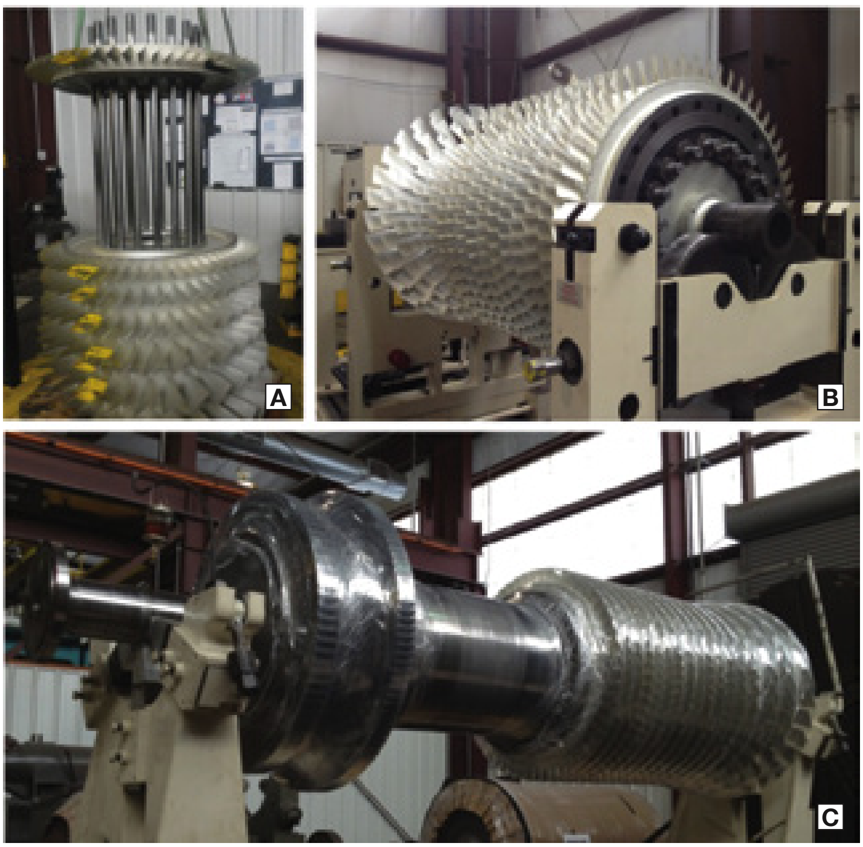
- Compressor stage-16 disc, dovetail cracks, blended out.
- Turbine stages 1 and 2, bucket rock, applied coating to dovetails.
- Fretted rabbets, installed patch rings, 12 small and one large.
- Compressor rotating blades, migration, shifted back into place and restaked.
- R0 compressor blades, erosion and foreign object damage (FOD), replaced.
- Through-bolts, nuts, and other hardware, wear and tear damage, reworked or replaced.

The most significant finding on this rotor was a 180-deg circumferential indication in the forward rabbet fillet of the first-stage turbine wheel (Fig 4). A crack like this could compromise the integrity of the component and militate against its continued use. More information was required for proper engineering disposition.

The depth of the indication cannot be determined with confidence from eddy current or other techniques, especially



5. Stress analysis of the repair was conducted using finite-element models



6. Final assembly of the compressor is in progress in Fig A with final inspection in Fig B. Reassembled rotor is wrapped to protect against the elements during transport (C) because it is located in a relatively small radius up under the rabbet surface. D-R engineers decided, with the owner's consent, that the first step should be to remove up to150 mils of material in the area of interest, which was considered a reasonable depth based on inspection results, calculations, and experience.

The indication cleared at 135 mils, as confirmed by eddy-current inspection. An additional 10 mils was removed for added assurance in the event there were any remaining indications below the detection capability of the inspection tools. Next steps: Apply final contour, then polish and shot peen the surface. Note that the contour was laser-scanned before and after the repair to enable a stress comparison for the actual part.

Finite-element models were constructed for both the original (OEM design) and repaired geometries (Fig 5). The primary goal was to show that the repaired configuration was as at least as good as the original. The mesh refinement in the model provided confidence that the local concentrated stresses in the fillet were acceptable. Through-bolt dead loading was considered important and was modeled with good fidelity. Low- and high-cycle fatigue and creep loading were factored into the analysis.

A mean-stress comparison showed the new contour reduced the peak stress in the fillet area by about 70% compared to the original design. Also, the point of peak stress was moved to the side of the fillet. The combined section stresses (membrane plus bending) are slightly higher than the original, but the much lower stress-concentration values more than offset the slight nominal stress increase attributed to the smaller cross section.

In sum, the repair achieved the following:

- Reduced substantially the stress in the fillet area compared to the original contour.
- Improved fatigue durability for both steady-state and high-cycle loadings.
- Enhanced component durability with additional surface treatments—polish and shot peen.

Final point: D-R engineers consider the repaired configuration superior to the original configuration in the region of the repair with respect to allowable number of starts and hours of operation.

Repairs complete, the rotor was reassembled, inspected, and returned to the plant (Fig 6). In-shop time from receipt to final assembly was three weeks. CCJ

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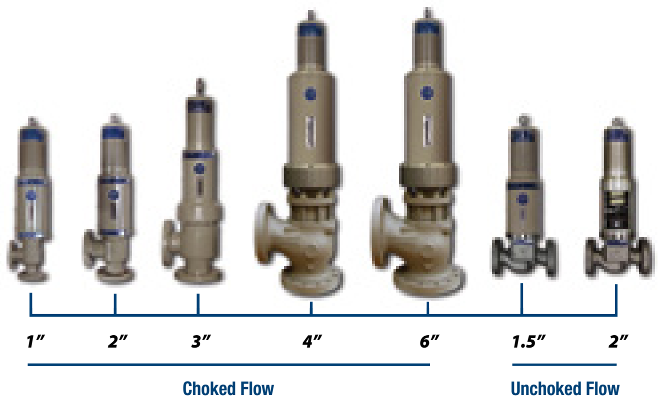

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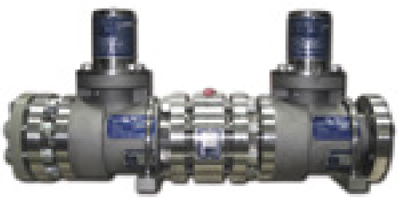

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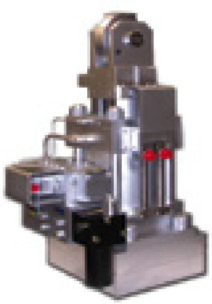
Currently in development is the **8650 Series All-Electric Inlet Guide Vane Actuator**, which is the first and only all electric IGV actuator to be introduced to the market. Scheduled for release in late 2013, the 8650 eliminates the oil leaks and varnish issues associated with hydraulic actuators, is scalable with forces up to 40,000 lbf, and has a drop-in footprint for easy replacement of many earlier hydraulic units.



For hydraulic applications, the **8277 Series IGV Actuator** is the most robust product available. Designed for use on large turbines, this dither resistant actuator operates from 1200 psi to 1700 psi of hydraulic pressure and is modularly designed for different cylinder sizes. To further improve the actuator's life span, shut dither feature off on MK controls.

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Fleet-wide monitoring program reduces losses

By Patricia Irwin, PE, Consulting Editor

In 2011, a large generating company experienced unplanned outages at two of its powerplants when a generator step-up unit (GSU) failed unexpectedly because of bushing problems. The loss of generating capacity, the cost of replacement, and the fear that other units might be at risk made it clear to the company that it needed to get a better handle on its transformers and their health.

In response, the power producer created an enterprise-level Transformer Program. In operation for little more than a year, the program has already identified eight critical problems and estimates are that it has avoided more than $6 million in replacement/outage costs (Fig 1).

1. The worst-case scenario. Proactive transformer monitoring, testing, and maintenance can greatly reduce the risk of a catastrophic loss

Create a solution. The generating company owns and operates a large fleet of combined-cycle and cogeneration plants in the US. There are more than 600 transformers at its facilities. Of those, about 200 are large GSUs. The remainder includes everything from small station service transformers (500 kVA) to large startup transformers (700 MVA).

The Transformer Program, created in 2012, tracks, monitors, and maintains all of the transformers. At its head is the Transformer Program manager, who comments, "Before we put this program together, we didn't have a good idea of how healthy our transformers were. Each plant was doing some type of testing and a few were doing a good job, but powerplant people aren't necessarily trained to monitor and maintain transformers."

This piecemeal approach to transformer monitoring was insufficient in several ways. "There was no consistency in the testing. A powerplant might hire a different test company each year. And, while the testing companies were providing data, they often did not interpret or explain what the results meant. Also, test results were typically delivered on paper and there was no mechanism to compare year-to-year results to look for trends," explains the manager.

The Transformer Program provides comprehensive testing, monitoring, maintenance, and repairs. Its goals are to:

- Determine the health of critical transformers.
- Improve transformer fleet reliability performance.
- Consistently update transformer health information so it can be used for strategic planning and maintenance work scheduling.
- Document the assessments to drive maintenance and planning.

Setting up the program took considerable effort. Since the company had few internal resources, one or more vendors would have to be hired. Further, the vendors would have to have national coverage, because the company's powerplants are scattered across the country.

The power generator initially hoped to hire one firm to take care of all transformer needs, from cradle to grave, but no single vendor could meet the requirements. In the end, it hired R B Watkins, an Alstom company based in Stow, Ohio, to do the electrical testing, SD Myers Inc, Tallmadge, Ohio, for oil analysis, and Doble Engineering Co, Watertown, Mass, for overall health evaluations and repairs.

While still a work-in-progress, the program already is paying off: Eight critical problems have been identified. "Three problems were identified by Alstom, while technicians were performing electrical tests or visual inspections. The other five were detected by SD Myers through oil analysis. Since the program began, the estimated savings (cost avoidance) is about $6 million," says the program manager.

Oil testing of all transformers is done at least annually. Some of the GSUs are checked quarterly and, if there are concerns about any unit, it will be tested more frequently. All oil testing in the US is performed by SD Myers at its Ohio facility.

According to Craig Schley, business development leader, SD Myers has been working with the generating company for nearly a decade, running tests for individual plants. The first thing SD Myers did after getting the national contract was to create a standardized testing program. "We have 34

field technicians in different locations throughout the country. They draw a fluid sample from each transformer, which is tested for the typical things, like combustible gasses. While at the powerplant, the technicians also perform a field inspection, looking for oil leaks, bad grounds, cracked bushings, etc." Note that while all the GSUs are oil-filled, some of the smaller in-plant transformers contain other insulating fluids, like FR3.

The oil is analyzed, and under the contract, turnaround is guaranteed to be less than five days. The results are reviewed by experts at SD Myers and the information is entered into a "dashboard" so engineers for the generating company can conveniently access the data, as soon as possible.

Schley explains what happens next: "If there are no problems, we send a notification, to let them know that their test results are available. If we find a minor problem, we will send a service alert to the plant and to the Transformer Program manager, to let them know there is something going on and the transformer might need to be serviced. If we find something seri-

Spares: What, where, and how to move them

Even with the best monitoring program, the generating company recognizes that it will need to replace a transformer from time to time. So careful consideration is given to how many spare units are needed, where they should be stored, in what condition (assembled with oil, or not), how they should be shipped, and installed, etc.

How many and what sizes? The lead time for ordering and receiving a new GSU is between 12 and 14 months. Therefore, if a GSU fails, the company needs to have a spare unit on hand to install or risk losing generation capacity at a plant for a significant period of time. To prevent this from happening, the transformer program team located and identified critical spares. In 2012, these transformers could cover failures for about 40% of the fleet.

The company evaluated the situation and began acquiring additional units, trying to choose transformers that could be used in multiple locations, where possible. In the last two years, seven spare GSUs were added and arrangements were made to rent other units in the event of a failure. By July 2013, spares coverage had risen to 92% of the fleet.

Stored where? Assembled or not? Some spare units are retained at powerplants. Many are centrally located so they can be shipped to any plant that needs them. Some are stored at the facility of the heavy-hauler that has the contract to move the units.

A big decision is how to store the spare transformers. If they are completely assembled and filled with oil, it will take some time to drain them, take them apart, and package everything for transport. On the other hand, if the spare unit is not filled with oil, moisture ingress becomes a concern. Also, by keeping the radiators, bushings, and miscellaneous parts in boxes, it becomes more likely that something will be misplaced or "borrowed" for another project.

To address these concerns, the company decided to maintain its spare units fully assembled and filled with oil. This will increase the time required to move and install the unit, but putting a large transformer in service takes about a month anyway. The additional time is not considered an undue burden. Alstom is under contract disassemble transformers as necessary and install them where needed.

Shipping. The company has made arrangements with several heavy-haul companies across the country to handle shipping. The haulers develop plans to move the transformers, which can be complicated. While many units can be transported most of the way by rail car, some will have to be shipped by truck across state lines, requiring multiple permits (Fig A).

A. Transport of large transformers can be challenging. While many units can be shipped by rail car, some must be trucked to the site

B. Onsite assembly of a replacement transformer takes time and skill. A big unit is not a plug-and-play device

The Transformer Program manager explains, "We try to take care of all the arrangements ahead of time and we update the plans regularly. With any heavy-haul plan, so many things can change. For example, a two-lane highway used to run in front of one of our powerplants. It is now a multiple-lane freeway. Getting a heavy hauler in there 20 years ago was one thing. Now it's something else entirely."

Installation. Once the transformer gets to the site, Alstom engineers and technicians are responsible for the assembly. "A lot of plant managers think that it's a plug-and-play situation. Well, not quite (Fig B). And, they don't understand why they can't energize the unit as soon as it is filled with oil. There is a process that has to be followed. It takes time to install a large transformer," cautions the manager.


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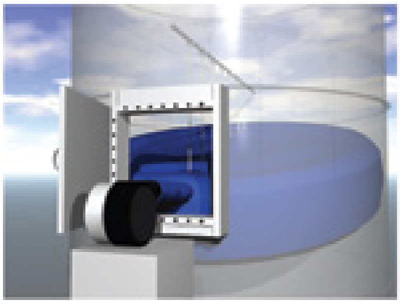
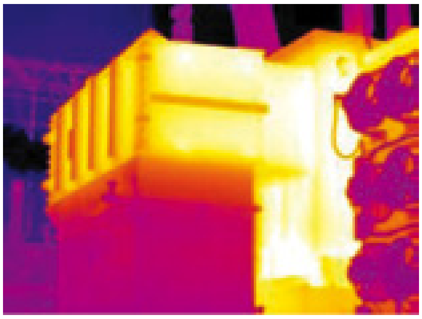




2. Hot spot! Comprehensive visual inspection includes use of infrared and other NDE techniques to identify problems

ous, like acetylene, we send a critical alert. That goes directly to corporate."

Besides providing test results through its dashboard, SD Myers also sends data to Doble in a standardized format, depositing them in a digital "drop-box." Doble then adds the new data to a master database, which it maintains. The oil testing program is definitely improving the condition of the transformers. Schley says, "Here's the best way I can put it: Nine years ago, when we started serving plants on an individual basis, there were a lot of critical alerts. Today, problems don't reach a critical level very often."

Electrical testing. "Two years ago, the generating company didn't have a comprehensive electrical testing program and they were having some failures. While each plant had a preferred transformer shop that it used, testing wasn't consistent and neither were the results," says Wes Watkins, Alstom's regional service manager. The transformers now are tested regularly. How often, depends on operating schedules, but typically every two years for the GSUs.

"Since the electrical tests are performed when a transformer is de-energized, we have to work around the outage schedule and that varies from plant to plant. Some plants might only have a three- or four-day outage, while others might be down for 30 days. I let the powerplants know which transformers are slated to be tested in a given year and they let me know on what dates I can have access to those transformers," continues Watkins.

Alstom has trained technicians throughout the US. They run the typical electrical tests: power factor, excitation, winding resistance, TTR on the in-service tap, megger the windings, etc. The technicians also do a comprehensive visual inspection and test all the gauges, alarms, fans, etc (Fig 2).

Once the inspections and tests are complete, Alstom design engineers review the data. If something looks amiss, they inform the program manager. Then, all the data are put into an XML file and sent to the generating company, which forwards it to the drop-box at Doble. Alstom's inspections have identified several critical problems and many non-critical issues; all were quickly addressed.

Overall trending and analysis. "It's one thing to test transformers and collect the data, but for that information to be valuable, it has to be analyzed. Doble has a multidisciplinary group of chemists and engineers to do that," points out Paul Griffin, VP of consulting and testing services.

All the test data from SD Myers and Alstom are sent to and analyzed by Doble. The drop-box simplifies the process. "Transferring large data files can be a challenge, so we set up this system. Testing companies can drop the information into a virtual box, which we check daily and load into our system," explains Griffin.

Doble does a full review of all that data on each GSU transformer (electrical, oil analysis, visual inspection, historical) and gives each unit a ranking. The color coded ranks start at "0" for "missing data." A rank of "1" means "unacceptable" and the numbers continue up to "5," for "in excellent condition." The rankings are provided online and give an overall assessment of each transformer. With a few mouse clicks, an executive or engineer can drill down further into the data and get more detailed information.

If there is a problem, Doble might recommend additional tests to aid with a diagnosis. For example, if the dissolved gas analysis showed there was a lot of hydrogen and a little bit of acetylene, an acoustical test to locate partial discharge activity might be needed. Specialty testing is arranged for by Doble.

By having all the data available, Doble experts can watch for problems and for trends. "In order to make sense out of data, you have to look at the recent information but, in some situations, you also want to compare that to the nameplate data. So, you are really looking at the whole story of each transformer," says Griffin.

The program is working and similar programs will probably become more common, according to Griffin. "I think you'll be seeing a lot more of this in the future, for two reasons. First, generation companies are getting larger and they need to understand the condition of their assets. Second, I know it's a common refrain, but the average age of transformers in the US is getting older every year. So, condition assessments are going to be more and more important." CCJ

Finish on-time, on-budget with better planning, preparation, execution

Freddy Alvarez has managed his share of gas-turbine (GT) outages. The former plant manager, now director of operations for Wood Group GTS, and colleague Chris Wilkinson, VP major maintenance, told GT users participating the webinar "Delivering a cost-effective outage on-time and on-budget," that a success-based attitude is what's critical to dealing with the unexpected and still achieving project goals. "You know going into the outage that you may find something wrong, Alvarez opined. "Having said that, the only question is, 'How do we still achieve success?'"

Let's say we're ready to start a gas-turbine outage on a Monday morning, he continued, and want to be ready by the following weekend to perform a cold start on the unit. We know that managing schedule and scope are very important and that every hour translates to cost, and we must continually explore opportunities to improve efficiency and control spend. To achieve success, Alvarez suggested focusing on three areas: planning and preparation, execution, and discovery.

He began by identifying the real risk to any outage plan: It's discovery during the execution phase of the project. Example: In the middle of the outage, the plant and contractor recognize they probably should do an extra item or two—that is, expand the outage scope. This presents the possibility that a workmanship issue may be encountered while performing the new work. What are the consequences of that with regard to inventory management? Do we have the parts?

What about schedule? Any schedule creep will have to be reviewed/coordinated with the other stakeholders: Power marketers/dispatchers, management, contractors, logistics, owner's engineer, other contractors onsite that may be affected. What about cost? Will there be market availability consequences, possibility penalties over and above the cost of the physical work?

Points made, Alvarez circled back to the all-important planning and preparation (PAP) phase. "The soft stuff is the hard stuff," he quoted a mentor as having said. Planning and preparation is not exciting, for sure, but single-handedly, it can impact efficiency and effectiveness the most. Invest the right resources and time into PAP and outage risks and potential cost impacts go down, Alvarez added.

Planning, preparation

Regarding the planning and preparation associated with work-scope development, he said, it's a data-driven process first and foremost. In Wood Group's experience, most plants are conducting the required equipment condition assessments and they rely on the computerized maintenance management system (CMMS) as their data repository. Both are very important, he stressed. Engage your contractors early, Alvarez urged. Providing them access to your previous outage reports, inspection reports, equipment database and work history, etc, is very important to creating a meaningful and complete work scope with the benefit being mitigation of discoveries during project execution.

The WG outage experts next introduced failure-mode effects analysis (FMEA), a risk management tool, into their presentation. Recognizing that everyone on the webinar did not use the exact same tools and acronyms, Alvarez explained: There may be other types of software or spreadsheets or processes that you follow, but what's important is their ability to identify risks in advance.

More specifically, a planning engineer identifies the tasks, the steps, the procedures that the outage contractor is going to perform—whether it be on a valve, the removal of a gas-turbine case, etc—and uses the analytical software to identify potential risks in that work and the probabilities of their occurrence. This process identifies high-risk items and allows you to prioritize work scope. Plus, if done early enough in the planning process (a year or more prior to outage start), you can use the results to develop realistic budgets for capital expenditures, labor, and consumables.

Failure-mode effects analyses are missing in many outage plans because plant owner/operators often choose to rely on a "standard" scope. Customers who do not see the value in FMEA before the outage sometimes realize it afterwards when their expectations have not been met. The bottom line: FMEA is a valuable, proactive tool for mitigating operational risks.

Alvarez transitioned to "cost," which he said requires an understanding of the "rules of engagement." Whether you're on the operations side or performing the work, you must understand what is, and is not, scope. If you have a term maintenance agreement, your knowledge must expand to understand what's planned, unplanned, and extra work. Add to that vocabulary in and out costs, logistics, division of responsibility, plus knowledge of who is responsible for the cranes, scaffolding, etc, as well as who really is in charge of the project and how to contact that person.

Last point is particularly important when you discover something abnormal and have to contact, at the moment, the person who can put his or her signature on a work order for a $50,000 repair. Better still, establish an extra-work purchase order in advance. Sure, there can be boundaries—a not-to-exceed dollar figure, for example—but a firm understanding of the processes and financial limits of extra work are critical for avoiding project stall. If applicable, review time-and-materials (T&M) pricing in advance, too, and discuss and agree on terms before the outage starts.

Scheduling was not a significant part of the presentation because of the ready availability of software, such as Primavera and Microsoft Project, which generally are well known to station personnel and are acknowledged as beneficial in the planning and coordination of work. He noted the value of these tools for identifying resource constraints and for schedule optimization when dealing with multiple contractors.

However, Alvarez was quick to point out that the availability of such tools is not the end-all to scheduling. He said scheduling requires discipline and a dedicated champion. It's not about appointing someone "outage coordinator" to update the schedule, it's about *managing* the schedule. The downstream effects of not managing the schedule include adverse impacts on the completion of tasks on time and within budget. The most successful outages were said to be the ones having dedicated managers focused on nothing else except managing administrative functions.

Sometimes, the former plant manager went on, we see a senior control room operator, or an operations manager, in charge of scheduling. Sounds like a great idea because these people certainly are in the know, but the problem is they're also needed elsewhere—such as for walk-down inspections, coordination of lock-out/tag outs (LOTOs), etc. Scheduling is a priority item; it demands a person dedicated to the activity.

Data trumps all arguments, Alvarez said. It reflects what the equipment is telling you and needs to be listened to. Of course, it's your responsibility to aggregate in the CMMS, on an on-going basis, all applicable photos, videos, links, and commentary from inspections and maintenance activities for use in developing outage scope. Regarding the last point, what are you seeing during preventive maintenance? For example, is the valve you're inspecting corroding? If so, enter that in your notes. What steps did you take to mitigate the corrosion? Put that information in your notes as well. The more detail, the better.

Predictive maintenance—for example, vibration monitoring, thermography, oil sampling, etc—contributes significantly to the accuracy of failure prediction. This information is reviewed during the outage planning phase to be sure you don't overlook an important action item. It also assists in identifying what parts should be ordered in advance of the outage.

Condition assessments are especially valuable for use in developing a meaningful outage scope and for identifying capital budget requirements. A year or 18 months prior to a major inspection, Alvarez said, conduct comprehensive condition assessments of major equipment—including heat-recovery steam generators, high-temperature piping, condensers, gas turbines, steam turbines, generators, etc—to the degree possible without compromising the plant's mission.

Operating and trip logs provide useful information as well, especially details on "abnormal" events that offer clues regarding the factors contributing to damage. Remote monitoring findings from the OEM or a third-party services provider is yet another source of data, particularly valuable for its trending of critical variables over time.

Alvarez then offered an example of how data from the foregoing resources, received and evaluated well in advance of an outage using FMEA and other analytical tools, identified the root cause of a problem that in all likelihood would not have been found otherwise. Critical to this solution, he said, was the partnering between WG and the customer.

Gaining access to all the data and sitting across a conference room table from the plant staff—an environment conducive to a free-flowing exchange of ideas—enables a capable contractor to understand in detail the plant's problems and tap the thinking of deckplates personnel who had been dealing with the issue, and trying to correct it, for years.

Here Alvarez stressed that there's no substitute for having the "right" people in this type of meeting. "If we're sitting across from a manager who just has a list of the trips, or a list of the information available, that's not nearly as good as having subject-matter experts from both the plant and contractor collaborate on the issue at hand."

This experience supported the notion of early contractor involvement. It's not possible to review data, identify problems, extract plant knowledge on issues, propose solutions for consideration by the owner in one or two outage meetings. It's an evolutionary process, he said. Plant personnel resources are limited for this type of collaborative investigative activity to be sure, but if you think of the effort as "discovery" in advance of the outage it becomes clear that the time constraints are far less onerous than when problems are identified during the outage.

Execution

The "ideal" outage profile is not the same for every plant; in fact, what's considered "ideal" for a given plant today might change by the next outage. In some cases, the spend may be what drives the outage scope and decisions; for other outages it may be schedule. Perhaps, too, there's a warranty constraint, a regulatory constraint. So, it's important for the major-maintenance service provider to understand the plant owner's priorities to assure an outage solution that meets expectations.

Alvarez stressed conducting inspections as soon as the outage starts—perhaps dedicating the first shift or two to inspections. The logic: If you're going to find something, discovery needs to happen early to minimize potential schedule impacts. Make every effort to have LOTO, confined-space, and hot-work paperwork completed *before* the outage starts.

On the first day of the outage the control room can look like a goat rodeo, the former plant manager said, with two- or three-dozen contractors, several-dozen representatives of those firms wanting to coordinate their work. You want to avoid this to hold costs in check and maintain high productivity.

Key is to get all the admin work done the day before and do walkdowns the night before. Having a plant subject-matter expert dedicated to the major-maintenance contractor contributes markedly to a smooth outage. That person is there when you conduct the inspections, Alvarez said, he or she helps you through the LOTOs, etc. It's like having a personal plant consultant from the operational side on your team—invaluable.

Hold points are important to discuss in detail before the outage begins. Plants have different hold points for witnessing and observing critical welds, tests, etc. The contractor, inspector, and plant owner have to manage their respective schedules and lost time results when these people are not in synch.

Discovery

Unplanned work is identified, so now what do you do? Alvarez said, "Find a deviation." Having onsite engineering disposition enables this, he added. Wood Group tries to have an engineer onsite, at least during critical operations.

Contingency plans are important to addressing discovery issues quickly and effectively. Formulation of contingency plans is part of the planning and preparation step, of course. Preapproving of parts, suppliers, and vendors is critical to maintaining outage schedule, and possibly cost as well.

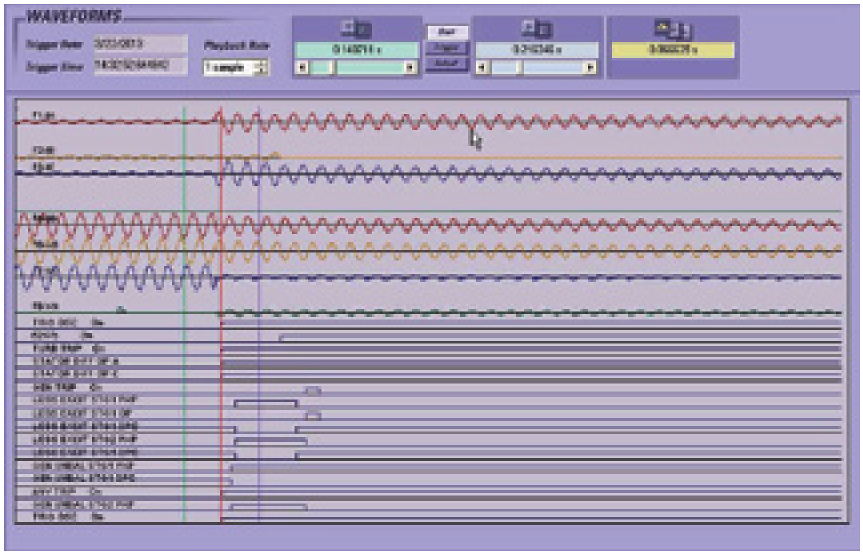
Understand your inventory requirements in advance of the outage so parts you expect to use are on-hand in advance of need. It's a good idea to revisit sharing agreements with neighboring plants in case you become squeezed for parts. Discuss with your contractor its ability to provide a just-in-time parts solution, a rotable exchange, etc. You can't do too much contingency planning, which should go beyond components to shop capabilities/time if needed. **CCJ**

Stator connection-ring vibration KOs H_2-cooled generator

The intense, four-hour electrical session at the Combined Cycle Users Group's 2013 meeting, chaired by Andy Donaldson, PE, VP of projects for WorleyParsons, focused on generators. The program featured three presentations by the respected consultant Clyde V Maughan, a recipient of the CCUG's 2013 Individual Achievement Award (sidebar), and one by Howard Moudy, director of service management for National Electric Coil, who is well known to gas-turbine owner/operators.

But it was a user who appeared to generate most interest among attendees for his brief, but compelling account of a massive failure in an 11-month-old, hydrogen-cooled generator at a combined-cycle plant. One can find hundreds of articles about the virtues of visual inspection of generators and the perils of dusting or greasing, but this was a rare public account of connection-ring vibration *in extremis*. Such sharing of knowledge among owner/operators is critical to the success of user groups, such as the CCUG.

In March 2013, the user began, the 225-MVA Unit 1 generator at a 3 × 1 combined-cycle plant tripped offline. The targets on both the generator and GSU transformer relays indicated a differential current fault on phases A and C. The metering had been set to capture event data. A screen shot (Fig 1) from the event recorder shows the sequence and magnitude of the event. The observations and tests during subsequent inspection and repair confirmed what the event recorder told engineers.



1. Screen shot indicates sequence of events and some of the damaged suffered by the Unit-1 generator

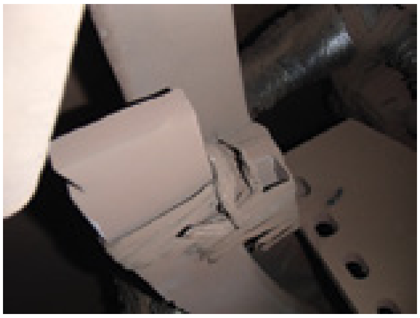
This generator started commercial operation in April 2012; the plant is vital to grid voltage support in that area of the power system. With two sister units at the critical plant, the owner was highly motivated to work closely with the OEM to determine the cause of the unexpected failure and to make the best repair.

Here is the sequence of events, as indicated by the recorder and other plant alarm panels:

1. A half-cycle fault to ground occurred first, triggering the failure. The generator is impedence-grounded, so the initial ground-fault current was attenuated.
2. Within five cycles after the stator ground was indicated, a phase-to-phase (P-P) fault was identified. The differential protection activated quickly, before the ground-fault relay timed out.
3. There also was a change in ground-fault current indicated while the P-P currents were flowing.

2, 3. Primary fault zone in Unit 1 was at the C- and A-phase jumpers to the connection rings, as shown from two angles

4. Broken tie and hole erosion in one of the gunstocks



5. Dummy ring pulled out of broken ties

6. Red bar shows where the dummy-ring was rubbing the C-phase jumper in Unit 2. Block on top is where the dummy ring broke away from the gunstock tie point

7. Dusting of ties and movement of the dummy ring and the A-phase jumper ties to the gunstock was clearly evident in Unit 2

Individual excellence, 2014

The Combined Cycle Users Group (CCUG) recognizes individuals for outstanding achievements in all areas of combined-cycle power production. The organization's Individual Excellence Award is presented annually to industry professionals who have demonstrated excellence in the design, construction, management, operation, and/or maintenance of combined-cycle facilities throughout their careers.

Nomination and selection process. Use the nomination form available on the CCUG website at www.ccusers.org to list the achievements and justification for the award. In addition to the submitter, two additional references should be provided.

Deadline for the 2014 award submittal is April 1.

The evaluation committee—Jimmy Daghlian of NV Energy, Brian Fretwell of Calpine Corp, and Andy Donaldson of WorleyParsons—will review all nominations, contact references as necessary, and with the support of the CCUG Steering Committee, select honorees. The awards will be presented at a special awards luncheon during the user group's 2014 meeting in San Antonio.

For additional information, contact Andy Donaldson of WorleyParsons at andy.donaldson@worleyparsons.com or 610-855-2645.

4. The generator breaker opened about four cycles after the P-P fault started, but energy from within the generator continued to drive the fault currents in the A and C phases until the magnetic excitation collapsed. The generator's internal energy was a big contributor to the extent of burning and loss of copper found when the machine was opened. Fault-current traces indicate total peak current into the fault area was about 60,000 amps.

Internal inspection indicated that the dummy ring at the 6 o'clock position had shaken loose from its glass ties to the gunstocks and had rubbed the ground wall insulation on the T3 C-phase jumper. Most of the damage was in the area where the T3 C-phase jumper is close to the T1 A-phase jumper (Figs 2, 3). Throughout the collector end of the machine there were multiple sites of tie wear and dusting to indicate movement and potential insulation damage. During the months that it took to return the unit to service, the owner and OEM team examined the evidence and performed tests.

The following is a synopsis of the Unit 1 findings:

- Felt compression was incomplete.
- Ties were not fully filled.
- There were gaps between tie wrap turns.
- There was dummy-ring migration and axial support erosion in tie holes.
- Broken ties were found at end-winding support arms (Fig 4).
- An empty tie hole was found at one end-winding support arm.

The conclusion was that the unit failed because a dummy ring moved enough to make contact with a phase jumper and damage the insulation. The dummy ring moved because of insufficient bonding within the tie system (Fig 5). Failure of bonding was attributed to improper felt compression and thermal growth of the fiberglass materials during the baking/curing cycle.

8. High-cycle fatigue cracks were found in Unit 2's axial support brackets

The failed Unit-1 stator was completely rewound; the rotor was rewound with existing copper. A connection-ring monitoring system was installed in Unit 1 to monitor the dummy ring.

Subsequent inspection of two sister units revealed similar problems with the dry-tie system (Figs 6, 7), along with high-cycle fatigue cracks found in the carbon-steel axial support brackets of Unit 2 (Fig 8). Repairs were made to the sister units using the methods applied in the rewind of Unit 1.

The presentations by Maughan and Moudy, as well as other participants in the CCUG meeting September 3-5 at the Arizona Biltmore in Phoenix, are available at www.ccusers.org. CCJ

Tweaking the Brayton, Rankine cycles to reduce heat rate

With gas-turbine OEMs offering combined cycles at efficiencies topping 60%, in some cases, you might think you've heard the last about cycle improvements. But that's not true. Enterprising engineers never stop looking for ways to tweak the Brayton and Rankine cycles to address shifts in the electric generation business caused by changes in regulations.

Recently, two former employees of Southern California Edison Co (SCE), Ron Kincaid and Mark Skowronski, PE, now the principals of MarkronTechnologies LLC, Los Alamitos, Calif, filed for patent protection on their combined cycle with regeneration (CCR) arrangement. Its primary advantage over a conventional combined cycle: Lower capital cost. The benefits of CCR are particularly compelling when reconfiguring conventional steam plants for combined-cycle service because the equipment necessary for a regenerative cycle already is in place.

Many coal- and oil-fired units that could be shuttered because of old age, or by regulatory edict because of pollutant emissions, are viable candidates for a CCR retrofit, Skowronski said—especially those built after about 1960 and having nominal steam conditions of at least 1800 psig/1000F/1000F. Gas-fired steam plants are particularly well suited for CCR conversion because the fuel-supply infrastructure exists.

Cycle overview. Fig 1 illustrates a conventional combined cycle with the benefit of regeneration. For a retrofit application, the regenerative portion of the steam plant (tinted area) would be retained as is. Only three feedwater heaters are shown here to simplify the drawing.

Important to note is the addition of a fired, mini heat-recovery steam generator in the exhaust duct upstream of the conventional HRSG. Purpose of the "regen-assist" combustion section is to raise the enthalpy of the GT exhaust; the heat added is extracted in the main-steam and reheat coils immediately downstream. Thus the enthalpy of the exhaust stream entering the conventional HRSG is the same as that with no regeneration.

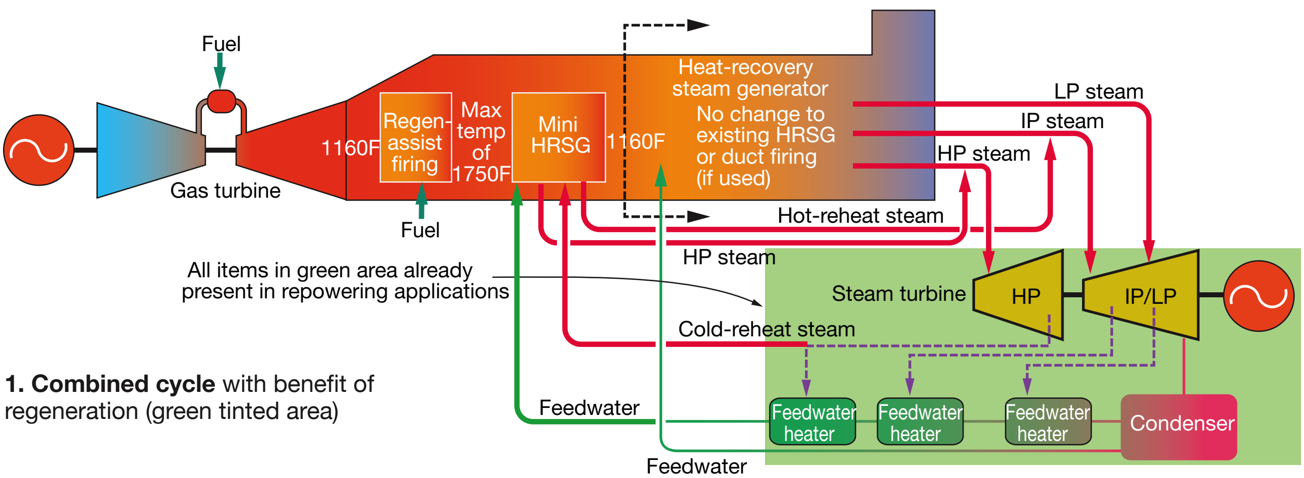
The amount of heat added and extracted by the mini HRSG varies with specific plant requirements. However, the temperature downstream of the regen burners generally should not exceed 1750F, based on the recommendation of the leading HRSG manufacturer Markron is working with.

Condensate flow is divided into two streams. One stream, with approximately 40% of the total flow, is routed via the feedwater heaters and heated by turbine extraction steam. It is directed to the HP module in the mini HRSG. The remainder of the condensate flows to the conventional HRSG. HP steam produced by both the mini and conventional HRSGs mixes at virtually the same pressure and temperature just ahead of the HP turbine steam chest. Likewise, cold reheat steam exhausted from the HP cylinder is reheated in the mini HRSG and combined with IP steam from the conventional HRSG ahead of the IP turbine.

If CCR is not used, Skowronski pointed out during a telephone interview with the editors,there are significant negative technical and financial impacts associated with reusing the steam turbine from a conventional steam plant as part of a retrofit combined cycle. For example, it might be necessary to blank-off bleed points, and/or reblade the turbine, as some have done.

Turbine flows, bearing loads, etc, change when the bleeds are eliminated, he said, and a considerable shop effort is required to adapt the turbine for use in the reconfigured cycle. Plus, a non-regenerative turbine is less efficient than a regenerative turbine so there's an ongoing heat-rate penalty associated with its use.

The former SCE consulting engineer (one of 12 in an organization with more than 700 engineers) added that the heat rate associated with the repur-



1. Combined cycle with benefit of regeneration (green tinted area)

posed regenerative cycle typically is the current net plant heat rate less 12% to 15%. Primary reason for the efficiency increase: There is no stack loss associated with using the CCR cycle.

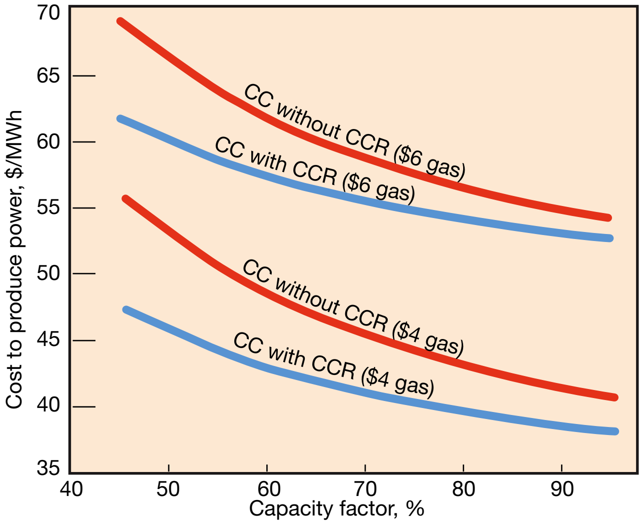
Skowronski added that this will always be about 600 Btu/kWh less than the combined-cycle heat rate with duct burners running full bore, because a regenerative cycle is more efficient than a multi-pressure cycle. The cost of adding the mini HRSG and associated piping to take advantage of this benefit is a nominal $75-$100/kW. This concept, the engineer continued, adds value by reusing the existing regenerative technology in-situ, and integrates with the new combined-cycle equipment to produce a low-cost alternative to a greenfield development.

Of particular interest regarding retrofits is the ability to fill the existing turbine with steam without having to install more GT capacity than might be required. This minimizes the "overbuild" when repowering a steam plant with a large turbine. To illustrate: A traditional repowering of a 470-MW steam turbine would produce over 1400 MW, whereas use of the CCR concept results in only about 800 MW.

Skowronski estimates that CCR reduces the capital outlay for repowering applications by 15% and for new installations by 35%. One plant owner familiar with the CCR system but with no opportunity for repowering told the editors it certainly was worthy of consideration for a new combined cycle. He said his company explores every real opportunity to gain a competitive advantage with higher efficiency. This same person thought it unlikely that retrofitting an existing combined cycle with a regenerative Rankine cycle would be economically viable.

Economics. Kincaid, the business half of Markron (undergraduate degree in economics, an MBA, and more than 25 years of experience in utility and power economics), ran through an analysis that showed an existing 470-MW coal-fired unit repowered with CCR results in an 800-MW combined cycle. This project currently is being discussed with a Texas utility.

Preliminary calculations reveal that repowering of an existing steam plant using CCR rather than a conventional combined cycle would produce $100 million in net present-value savings. Kincaid based the analysis on a $550/kW capital cost for a conventional 800-MW combined with a localized heat



2. Levelized total cost of repowering with a conventional combined cycle is compared to that for a combined cycle with regeneration

rate of 6900 Btu/kWh.

Repowering with a 2 × 1 CCR reduced the capital cost to $375/kW because a new steam turbine was not required and the GTs and HRSGs would be smaller than those required for a conventional combined cycle. In this case, the weighted average heat rate was 7280 Btu/kWh, or 380 Btu more than for a conventional combined cycle.

Fig 2 compares the levelized total costs for repowering with a conventional combined cycle and with a CCR, at different gas prices. The curves assume O&M is $20/MWh for both cycle arrangements.

Case history. A cursory review of plant data available in the CCJ offices pointed to several steam units nationwide rated between 100 and 200 MW and installed between the mid-1960s and mid-1970s. Stands to reason that no one would be upgrading emissions controls on coal-fired units in that range and gas-fired units could be replaced by one or two LMS100s with a better heat rate. In the minds of the editors, these might be candidates for a combined-cycle retrofit and asked Markron to run a "back of the envelope" engineering/financial analysis assuming repowering with a conventional combined cycle and CCR.

The station selected by the editors is equipped with two 110-MW gas-fired boilers and reheat turbines having a throttle flow of 750,000 lb/hr of 1900 psig/1000F steam. Five stages of feedwater heating are used and the design station heat rate is 9800 Btu/kWh. Gross turbine heat rate is 8000 Btu/kWh. The foregoing numbers are nominal. Here's how the analysis worked out:

Skowronski proposed a 2 × 1 combined cycle powered by two GE 6FAs. With the 15% altitude derate required for the site selected, the owner gets 200 MW of total combined-cycle output, including 72 MW of regular combined-cycle steam. Adding 43 MW of CCR nearly fills the newest of the two steam turbines to its maximum capacity of 115 MW. Total station output would increase by 17 MW to 243 MW.

Kincaid jumped into the conversation at this point, saying that the cost for the repowering project would be about $400/kW ($97 million) and have an annual carrying charge of $12.1 million. The fuel saving, estimated at 3330 Btu/kWh would total $19.5 million annually—assuming a 55% capacity factor and gas at $5/million Btu. This results, he said, in an annual net saving of $7.4 million and a 30-yr present value of the saving at about $75 million.

A new brownfield combined cycle at the same site with the same output (if available) would cost $133 million and have an annual carrying charge of $16.6 million. This unit would reduce fuel cost by $21.4 million/yr, making the annual net saving $4.8 million as compared to the CCR repowering net saving of $7.4 million yearly.

Keep in mind that the foregoing example is for a relatively small steam plant. The CCR approach may provide even greater benefits for the repowering of larger steam plants (those with ratings of 400 to 500 MW) because of their significantly lower conversion costs (per megawatt basis) and their greater flexibility in sizing the repowering project to meet load requirements.

Ultrasonic flowmeter differentiates between water and steam in HRSG drain lines

You may recall the old one-liner, "Everyone complains about the weather, but no one does anything about it." The same could be said about superheater and reheater drain systems for heat-recovery steam generators (HRSGs). Improperly specified, designed, and/or installed drains continue to support welders and aftermarket suppliers of SH and RH harps, headers, and tubes despite years of discussion

at user-group meetings regarding the origin of the problem and appropriate corrective action.

However, ongoing work sponsored by EPRI is expected to finally help owner/operators protect their HRSGs by providing positive indication of condensate-free heat-transfer panels and drain systems prior to plant startup. A clamp-on ultrasonic flowmeter is believed the key to success. The EPRI effort is directed by Senior Project Manager Bill Carson, who spent nearly two decades as the boiler program manager for Dynegy Inc, one of the industry's leading independent generating companies, before joining the R&D organization.

Bob Anderson, principal, Competitive Power Resources Corp (CPR), Palmetto, Fla, may well be the industry's drains conscience, having been involved in the analysis of condensate formation and behavior in superheaters and reheaters, as well as the redesign of ineffective drain systems, for more than a decade. Interestingly, not much has changed regarding problem definition and corrective action since Anderson's first CCJ article, published 10 years ago (Winter 2004 issue). A recent assessment of the industry's drains issues, based on the experiences of HRSG experts from HRST Inc, Eden Prairie, Minn, tells much the same story.

The editors called Anderson after receiving a note from a highly experienced combined-cycle asset manager that reflected his frustration with poorly designed drain systems (for example, no allowance for thermal expansion) and cycling beyond design assumptions which exacerbates valve problems, corrosion, etc.

Given the years of talking and basic fixes available—such as better valves and materials, upgraded piping design, etc—the editors wrongly believed that most plants would have already replaced under-performing drain systems. Not so, said Anderson, "I still routinely find condensate (and undrained attemperator leakage during layup) migrating through the superheater."

The former manager of combined-cycle services for Progress Energy Inc then advised he was "doing quite a lot of work on drain control." At that point, Anderson mentioned EPRI's work with ultrasonic flowmeters and their ability to sense the difference between water and steam in a pipe, as well as CPR's experience with the same technology for a major European power producer. "In addition to working out how to control the drain valves," the consultant continued, "the field testing associated with this research has identified some interesting things going on in drain pipes regarding when and how the water moves—or does not move."

The challenge is to know when there's water in the pipe and when there's steam in the pipe so you know when to open the valve to let the water out and when to close the valve to keep the steam in. Sounds simple but it's not. "Early in the startup on the vast majority of HRSGs, there's no definitive way to tell what's in the pipe," Anderson said.

Some believe condensate pots are the answer, he continued, but that's not necessarily so. For example, to be effective on an F-class superheater, they must be relatively large and their installation in space-starved locations under the HRSG can be virtually impossible. Furthermore, the pots can suffer thermal-fatigue damage from the temperature transients they experience in cyclic service; plus, the level switches, conductivity probes, and other instrumentation required for proper operation is expensive and often a maintenance headache.

Some users believe putting thermocouples on superheater and reheater tubes may be the answer. Anderson, who has done significant work in this area, finds that while TCs sometimes can be used to monitor drain-system performance, they cannot be used to control the operation of drain valves. He points out that TCs mounted on tubes don't "see" what's in the drain pipe; they only can detect undrained water that is carried up into the tubes by steam flow.

Anderson said that about three years ago, Carson's boiler solutions team at EPRI began discussing the idea of using ultrasonic technology to control superheater drains. Anderson did some digging, identifying an instrument from Flexim Americas Corp, Edgewood, NY, that might meet the industry's requirements.

Flexim experts explained that ultrasonic flowmeters have no moving parts and minimal calibration and maintenance requirements—ideal for powerplant application. Plus, they can be mounted directly on the outside of the pipe, non-invasively. Measurements are made using the transit-time difference method. It exploits the fact that the transmission speed of an ultrasonic signal depends on the flow velocity of the carrier medium. An ultrasonic signal moves slower against the direction of flow, faster with it.

It works this way: Two ultrasonic pulses are sent through the medium, one in the direction of flow and the other opposite. The meter measures the transit-time difference and calculates the average flow velocity. Ultrasonic flowmeters are not affected by density and automatically compensate for variations in viscosity, giving them the ability to differentiate between water and steam inside the pipe.

Early in 2012, CPR was commissioned by EPRI to help an Italian utility start up its combined cycles faster without damaging equipment. Italy has a relatively large amount of wind and solar generation requiring frequent cycling of conventional generation. By the time Anderson got to Europe, EPRI had already conducted some preliminary tests with ultrasonic flowmeters in the US. Based on Anderson's recommendation, the Italians have installed these instruments at three plants to evaluate the effectiveness of their superheater drains.

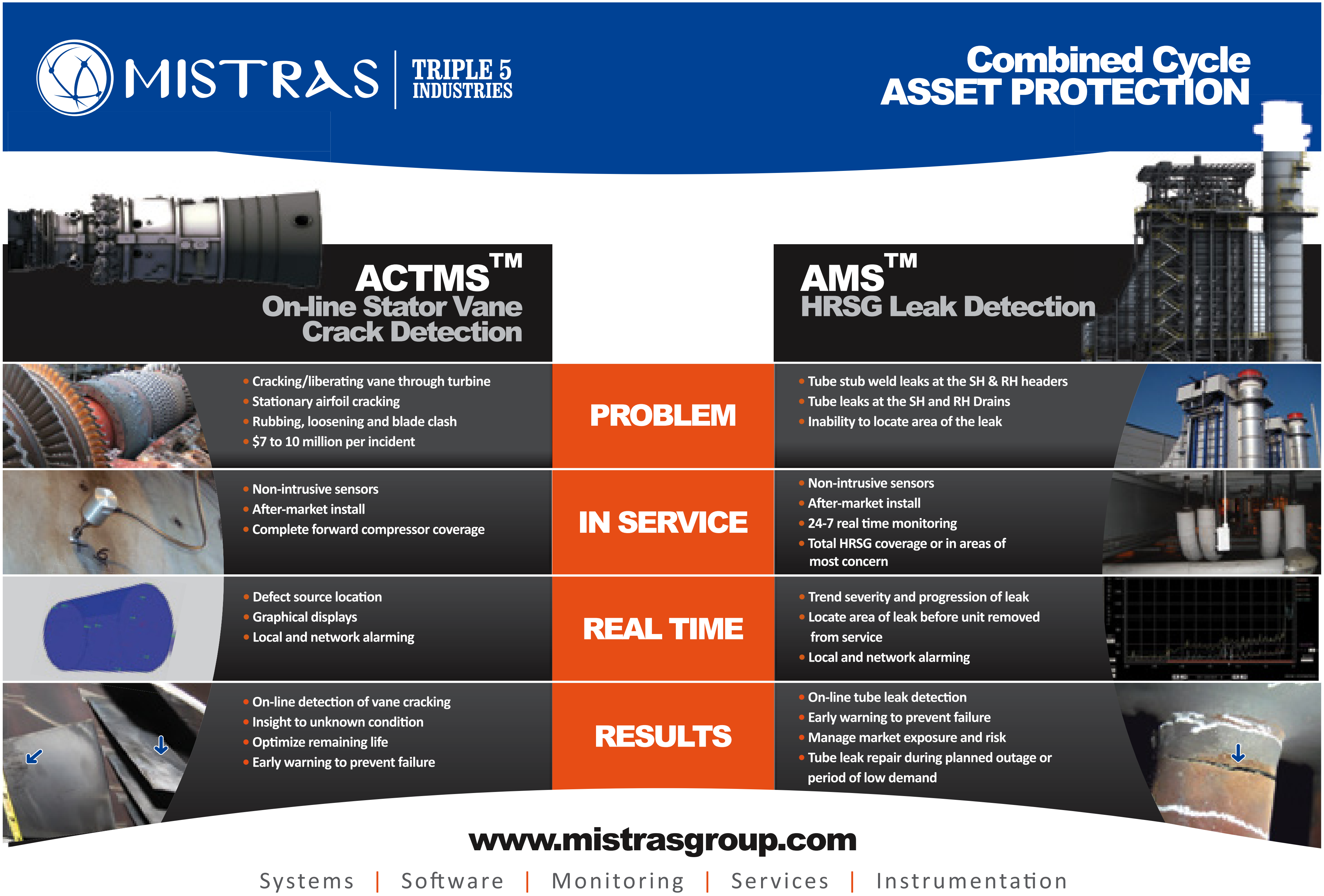
Here in the US, EPRI purchased a couple of Flexim flowmeters and arranged a prototypical system to automatically control the drains on one HRSG at Oglethorpe Power Corp's Thomas A Smith Energy Facility. Initially, one meter worked well but the other didn't meet expectations. Reason for the latter was that part of the drain system was running slightly uphill so it didn't fill with water when the valve remained closed. The meter was moved to a lower point in the system allowing the meter to "see" water in the pipe and open the drain valve. Test passed.

Next step is to continue the research at Smith with a permanently installed meter configured only for automatic drain control. The portable meter and all of its associated instrumentation then will be used for testing at other plants. Meanwhile, Flexim says it's developing a dedicated product for HRSG applications that it plans to introduce in 1Q/2014.

Sensing a winner, Kraft rolls out TurboPHASE on the industry's biggest stage

Bob Kraft, founder and CEO of PowerPHASE LLC, showed he hasn't lost his ability to conceive, develop, build, promote, and sell products of importance and value to the electric power industry. Kraft, you may recall, was one of the founders of Power Systems Mfg LLC, better known today as PSM.


Kraft


MISTRAS
TRIPLE 5 INDUSTRIES
Combined Cycle
ASSET PROTECTION
ACTMS™
On-line Stator Vane Crack Detection
AMS™
HRSG Leak Detection
PROBLEM
• Cracking/liberating vane through turbine
• Stationary airfoil cracking
• Rubbing, loosening and blade clash
• $7 to 10 million per incident
• Tube stub weld leaks at the SH & RH headers
• Tube leaks at the SH and RH Drains
• Inability to locate area of the leak
IN SERVICE
• Non-intrusive sensors
• After-market install
• Complete forward compressor coverage
• Non-intrusive sensors
• After-market install
• 24-7 real time monitoring
• Total HRSG coverage or in areas of most concern
REAL TIME
• Defect source location
• Graphical displays
• Local and network alarming
• Trend severity and progression of leak
• Locate area of leak before unit removed from service
• Local and network alarming
RESULTS
• On-line detection of vane cracking
• Insight to unknown condition
• Optimize remaining life
• Early warning to prevent failure
• On-line tube leak detection
• Early warning to prevent failure
• Manage market exposure and risk
• Tube leak repair during planned outage or period of low demand
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Only a year ago, he introduced *on paper* TurboPHASE™, a compressed-air system for boosting gas-turbine power, promising it would deliver peak capability within a minute or so after pressing the "start" button. [link to QR1] At Power-Gen in mid-November, Kraft unveiled a full-scale system at the PowerPHASE booth (Figs 1, 2)—one of the busiest on the show floor. An operating permit could not be obtained in time, so he showed a video of the first commercial system under test. [link to QR2] The first installation at a generating plant is expected early in 2014. Stay tuned.

How TurboPHASE works

Engine on test stand

TurboPHASE is simple in arrangement, consisting of a high-efficiency air compressor driven by either a reciprocating engine or small gas turbine, and a heat-recovery system. The latter is used to capture exhaust heat from the prime mover and raise the temperature of the compressed air to match the GT's compressor discharge temperature before the additional air is injected into the gas-turbine wrapper.

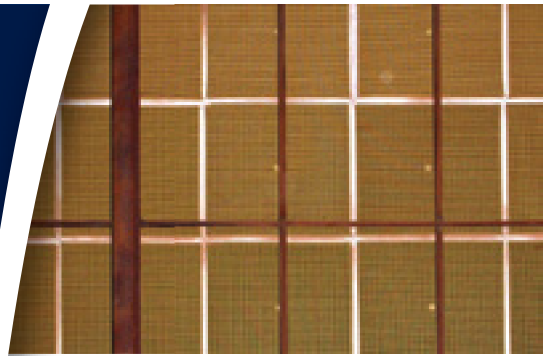
The benefit: Even on a 95F day, the gas turbine can generate its ISO-rated power at a better heat rate and at the same emissions rate as usual. The TurboPHASE module is skid-mounted and its small footprint enables relatively easy relocation if economics change. It can be installed and commissioned within three days.

Using the performance calculator on the PowerPHASE website (http://turbophase.net) you can quickly evaluate the economic benefit TurboPHASE brings to your plant. The editors analyzed its value for a simple-cycle 7EA located 1000 ft above sea level on a 90F day. ISO output of the engine is 82,276 kW with a heat rate of 10,635 Btu/kWh. For the site conditions and without TurboPHASE, the engine would produce only 71,167 kW at 10,943 Btu/kWh.

With one TurboPHASE module, output increases to 74,080 kW and plant heat rate decreases by 69 Btu/kWh. Installing two TurboPHASE modules increases output by 2913 kW while reducing heat rate by another 63 Btu/kWh. Four modules can restore power output to ISO conditions on a 90F day while reducing ISO heat rate by 245 Btu/kWh.

Another illustration: If you have a nominal 500-MW F-class 2 × 1 combined cycle, you can gain 50 MW with 10 TurboPHASE modules located on a 70 × 70 ft plot of land. CCJ

1, 2. TurboPHASE is assembled for display at Power-Gen (above); on the show floor (below)



Users push tomorrow's automation technology into today's plants

It's no secret that quality technology transfer takes place increasingly at user-group meetings. This year's Ovation Users Group meeting, sponsored by Emerson Process Management Power & Water Solutions, was no exception. Highlights included: experience with virtualization; the expansion of open-architecture connectivity; more innovation in wireless applications; making valves smarter; escalating situational awareness for operators; and embedding advanced predictive, prognostic, and optimization capabilities in control systems.

When you consider the presentations as a whole, perhaps the greatest revelation is that the promise of a fully integrated automation and plant knowledge management platform is now being realized. The days of data streams in silos, disparate plant control systems, and narrow one-off applications is over. If your goal is to streamline data systems, it appears possible now to standardize on one enterprise platform for the entire plant.

Next new thing is here

At the end of the article summarizing key points made at the 2011 Ovation Users Group meeting, "Ovation users glimpse the future, consider today's solutions," 3Q/2011, p 62), CCJ editors mentioned virtualization in the section "What's emerging." This year, in-plant experience was reported by one user with a virtualization pilot program at a coal-fired plant. The technology is applicable to many varieties of plant computers.

Virtualization in this context refers to using software to get more productivity out of existing computer hardware. It allows you to run multiple operating systems on one physical machine by creating a "virtual machine" using software that replicates what the operating system does in the hardware. While the technique, based on technology from VMware, has been prevalent in Windows-based workstations, Emerson also has applied similar technology to Ovation controllers, valve-position modules, and Ethernet link controllers used for simulation.

The result: This coal-fired plant added several operator screens in the control room with a minimum investment in added computer infrastructure (Fig 1). Another benefit is that it is much easier to recover from upsets using software rather than rebuilding workstations. The plant is considering extending the virtualization to domain controllers, database servers, and historian, as well as adding virtual simulation.

Situational awareness

One of the unintended victims of digital technology has been plant operators. The issues include data fog—too much information coming at them improperly organized—and poor human machine interfaces (HMI). Earlier this year, CCJ summarized a presentation by Harvey Ivey, manager of I&C systems and field support for Southern Company, on HMI given at the EUCI-Pearl Street Inc conference, "Managing the Digitally Integrated Power Plant" (see "The leading edge in managing plant digital assets," 2Q/2013, p 28). Ivey gave a similar presentation at the Ovation meeting.

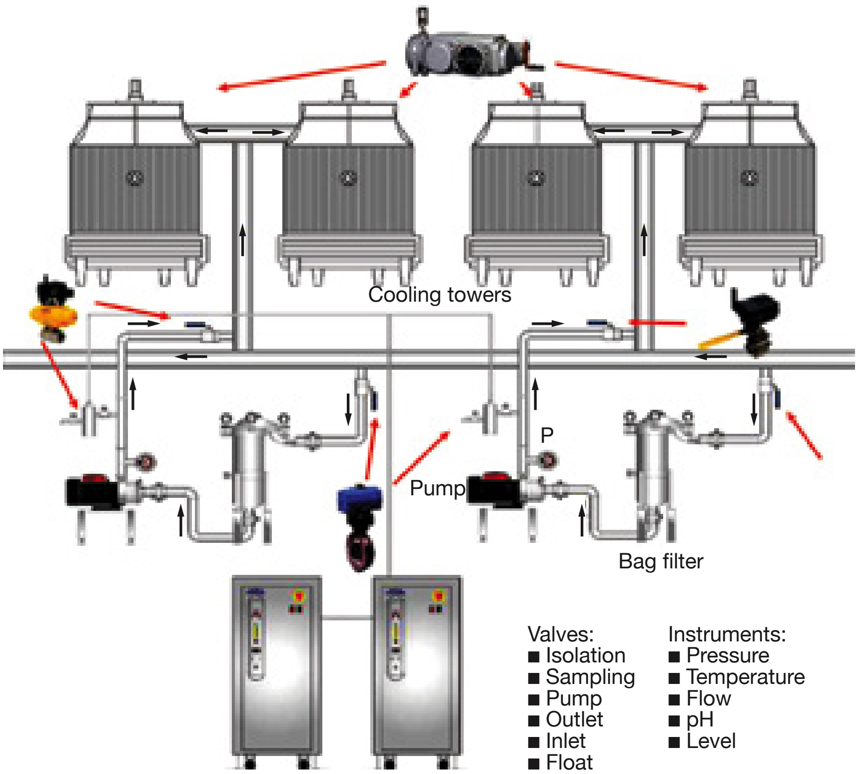
A representative from one of the largest global powerplant owner/operators offered his company's experience on ergonomic design, incorporating control-room layout as well as operator graphics. It should be noted that both Ivey and this user referenced "The High Performance HMI Handbook," by Bill Hollifield, a consultant specialist with PAS Inc, Houston. In this case, pictures really are worth a thousand words, when you compare the control room layout designed by the plant personnel (Fig 2) to that by the architects.

To design a control room, the owner's task force undertook an elaborate "adjacency" analysis to determine how the main elements of the control room should be positioned relative to each other; and a sight analysis, how things should be positioned relative to the operator's eyes. The keys to their thinking on HMI were (1) to give information to the operator about the state of the equipment, not explain to them how a powerplant works, and (2) to develop their own standards and conventions for mimic displays, relative attention and value/priority ranking, navigation, and linkage to Ovation graphics.

ORIGINAL   AFTER UPGRADE

1. Virtualization enabled plant to remove significant hardware from behind the control-room workstations

2. Control-room design concept proposed by company architects (left) was significantly different from the one proposed by the plant task force (right)—and accepted



3. Adding intelligence to—in this example—cooling-tower I&C through wireless technology allows you to take advantage of the AMS Suite for digital maintenance management

Gone wireless

One of the most unheralded advancements in automation is the progressive capability of wireless technology. Emerson's Joe Cipriani and Scott Stofan made this point emphatically, declaring, "wireless applications aren't niche, they are everywhere!" Although cybersecurity has been cited as a barrier to wireless, best-in-class solutions are available to keep wireless networks safe. The presenters noted that, for a typical boiler or HRSG 300 meters from a control room, wireless can reduce capital cost for instrumentation by 42%.

These devices are no longer for remote equipment too expensive to instrument in wired networks. As just one example, a customer purchased 117 wireless devices, 56 pressure and 61 temperature sensors, for a set of five turbine/generators at one power station. As a result, operator rounds have been sharply reduced, downtime reduced through better diagnostics, and startups are quicker because the plant can take advantage of fast-start logic enabled by the new measurements.

For one of its plants, a West Coast utility reportedly cut maintenance on the turbine compartment by 50%, improved turbine efficiency, lengthened cooling fan life, and reduced parasitic power consumption. This was through wireless temperature transmitters that indicate hot-air leaks in the turbine compartment, pressure transmitters that detect cooling-air leaks from forced-draft fans (reducing amperage), and DP transmitters that detect air-filter plugging. Other wireless technology examples cited include boiler-feed pumps, economizers, feedwater heaters, air heaters, cooling water intake facilities, generators.

Valves—smart and ordinary

Not everything in automation involves the glitzy new digital smarts. Desuperheaters are a problem area in many combined cycles. Improper desuperheating causes tube stretching, tube metal failure, cold-reheat header cracking, water hammer, spray-nozzle failure, and other ills, noted Josh Crompton, of the Emerson Fisher Power Team. Although some plant personnel have not been informed of such, he recommends that spray nozzles in all desuperheaters be replaced every 18-30 months, and that insertion-style nozzles be inspected annually. Plus, strainers always should be used upstream of the spray-water control valves.

Severe-service valves for combined cycles include feedwater control, with the most common problem being leakage. Entrained particulates often cause erosion conducive to leakage. For this application, the severe-service valves generally recommended have protected seats and large passages to allow particulate through without inducing damage.

Of course, adding smarts to your valves shouldn't be neglected. Mike Rooney, Emerson Process Management/Valve Automation, calls intelligence to electric actuators serving turbine isolation/main steam stop valves, boiler-feed and makeup water pump valves, boiler drain valves, cooling-tower pump discharge (Fig 3), and others "a perfect application for wireless technology."

Adding intelligence this way allows you to open and close valves remotely; detect loss of power phase, torque switch trip condition, motor overload trip conditions, and loss of internal control voltage; check on remote enabled commands; and monitor actuator position. At the valve, you can detect jammed or stalled conditions and conditions leading to increased force to operate. In addition, all the valves can be monitored and managed through the Emerson AMS Suite using a consistent dashboard to organize all the relevant valve information in one place.

Predicting, optimizing

Predictive control is the "next generation," according to Jeff Williams. Emerson's version of model predictive control (MPC), a generic class of algorithms, is called Dynamic Matrix Control (DMC). Essentially, the control of the process is performed by compar-

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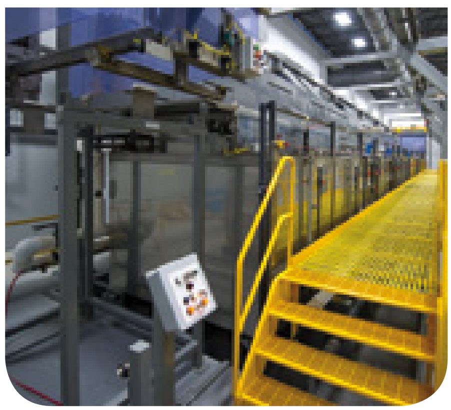
In July 2011, TCT opened a new, custom-built overhaul and repair facility in Airdrie, Alberta. Conveniently located 20 minutes north of Calgary, Alberta, the new facility houses production, project management and support staff for both TCT's General Electric Level 4 services and Rolls-Royce MROC services. This purpose-built facility is 220,000 square feet and is complete with state-of-the-art equipment and tooling. TCT is proud to offer all of its customers immediate induction for all engine types.

TCT has completed construction on a state-of-the-art LM6000 test cell, located in Calgary.



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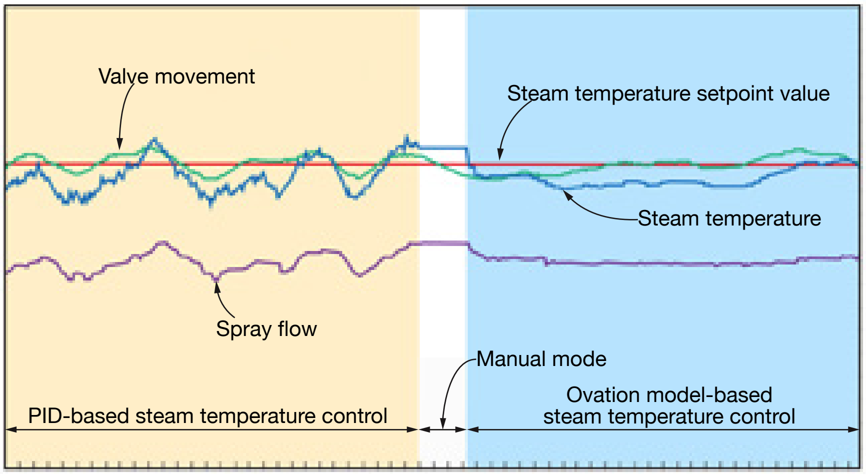
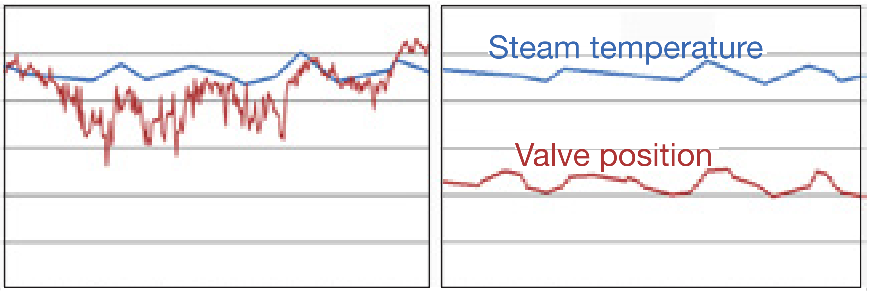


4. Dynamic Matrix Control concept (right) is compared to conventional PID control (left). Note the immediate positive benefits of model-based control



5. Another look at improved temperature control offered by switching from PID (left) to a model-based application (right). Reduced modulation of the final element will improve the longevity of the control valve, reduce thermal fatigue on the HRSG, and extend maintenance intervals

	Unit operational review	Steady-state process and control analysis	Dynamic process and control analysis	Turbine mechanical and auxiliary systems	Generator and excitation control review	Operations assessment	I&C architecture assessment
Plant A with known drum-level control problems	✓	✓	✓				
Plant B with suspected technology life-cycle issues	✓	✓		✓	✓		✓
Plant C interested in improving cycling performance	✓	✓	✓	✓	✓	✓	✓
Plant D typically base-loaded but with aging-workforce issues	✓					✓	✓
Plant E looking for better participation in ancillary services market	✓	✓	✓	✓	✓	✓	✓
Plant F with process issues of unknown root cause	✓	✓	✓			✓	

6. Menu of options identifies services available through Ovation to improve combined-cycle performance for specific objectives

ing step changes in control response to a predicted response based on the model. There is a "control" horizon and a "prediction" horizon.

Models are formulated using control variables, manipulated variables, and disturbance variables. The technique essentially replaces the traditional PID (proportional integral derivative) used for decades in powerplant control (Figs 4, 5). PID is a reactive technique, DMC is a proactive technique, noted Williams. Emerson has developed models for steam temperature control, load control, and optimization.

While there are still limitations as the models are refined, two plants reportedly are running optimization models successfully. For combined-cycle plants specifically, Williams, in another presentation, covered loading optimization across multiple units, compressor wash optimization, and unit response optimization for cycling and responding to the ancillary services markets (Figs 6, 7).

For controlling the impacts of cycling, Emerson adds capability that more precisely controls steam temperatures, controls ramping consistent with limitations of the HP steam drum, and ramps at the highest rate allowed by the steam turbine, all in a coordinated fashion. Most combined-cycle control schemes do not optimize the start-up process, because of the low level of automation provided in the original design.

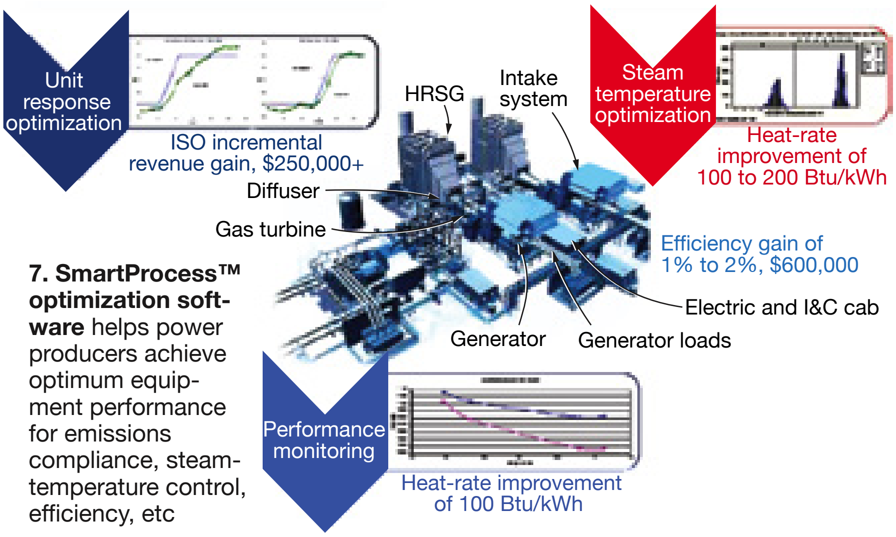
When it comes to gas turbines and combined cycles, it is important to realize, or remember, that the monitoring system typically provided by the OEM is for protection only, to guard against a catastrophic failure. That is, they shut down the unit if any out-of-bounds conditions are detected. Reuben Wunder, a subject matter expert for Emerson's Machinery Health Management business, discussed how Ovation users can go beyond the traditional protection measurements, including turbine bearing accelerometers, turbine axial thrust, turbine case vibration, intake pressure, intake pressure, speed, and shaft position.

Today, Ovation products include a complete turbine monitoring solution fulfilling API 670 criteria for key monitored areas, as well as predictive monitoring that goes well beyond protection. Backbone of the solution is the CSI 6500 prediction system which includes eddy- current probe resting and dynamic position, full-spectrum analysis to detect turbine/case rubbing, and interactive 3D displays of the turbine shafts. Also featured:

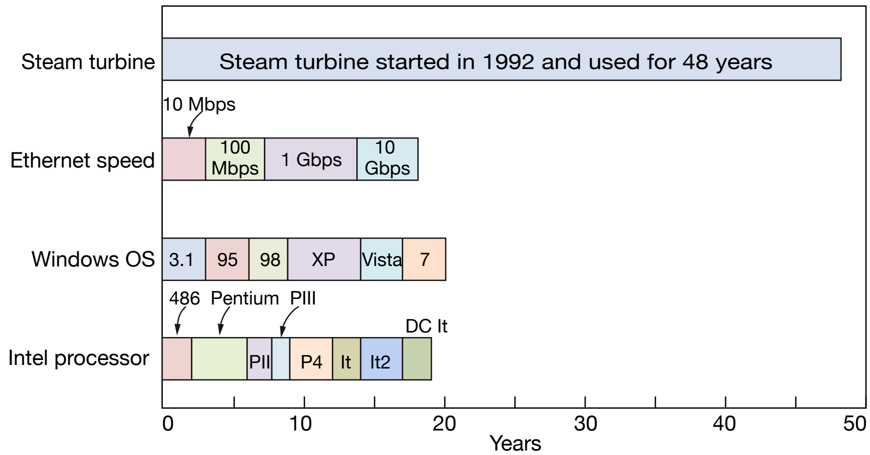
- Simultaneous and continuous transient recording of all protection channels at over 5000 samples/second.
- Patented PeakVue technology to monitor turbine bearings.
- Ease of integration with CSI data populating Ovation faceplates.

But Ovation can also "layer on" to the existing protection and supervisory systems. Wunder illustrated this using an Ovation retrofit at a powerplant that converted to combined cycle from a simple-cycle unit. This was said to be one of the first Mark VI controls retrofits. In this case, Emerson integrated the GE EX2100 excitation system such that its functionality can be controlled through Ovation, and included the AMS Suite, and the CSI6500. In subsequent phases of the project, Ovation will provide direct control and monitoring of the HRSG, burner management system, feedwater and water treatment systems, substation equipment, and steam-turbine supervisory control.

In another example, during com-



7. SmartProcess™ optimization software helps power producers achieve optimum equipment performance for emissions compliance, steam-temperature control, efficiency, etc



8. The pace of change of the digital-technology "brain" is far faster than that of steam-turbine "brawn"

missioning of an 8100-rpm, 1500-hp turbo-compressor, a high vibration level was detected in the expander, but because no mechanical issues were discovered, the vibration alarm levels were raised and the turbine operated for a year. To determine the root cause, the plant brought in Emerson to overlay its prediction system onto the protection system. Immediately, noted Wunder, the system revealed a sub-synchronous vibration component and the sub-synchronous peaks were creating an unstable orbit.

Well-connected automation

The example above is only one illustration of how Emerson has positioned Ovation as a platform, the gateway to other plant knowledge systems, as well as a completely integrated automation and enterprise solution. The table shows how well connected Ovation is to third-party systems important to combined-cycle owner/operators.

Emerson has completed over 600 retrofits for gas-turbine control systems, and continues to acquire new references on legacy automation systems provided by OEMs. Emerson's Laurence O'Toole and David Cicconi, in their presentation, listed the following models for which Emerson has retrofit experience: Westinghouse 171, 191, 251, 501 (all models); GE Frames 3, 5, 6, 7 (all models); Siemens 84.2, 64.3; Pratt & Whitney FT4, GG3, GG4; GE aeros LM2500, LM1600;

Ovation connectivity platforms

Serial link controller	Ethernet link controller	SCADA	Third-party I/O
Protocols (Ovation release independent)	**Protocols (Ovation release independent)**	**Protocols (Ovation release dependent)**	**Protocols (Ovation release dependent)**
Allen Bradley GE Mark IV IEC 870-5-101 Ingersoll-Rand MP3 Modbus master Modbus slave Vilter data link ***. . . And more***	Allen Bradley CSP client Allen Bradley DF1 client Allen Bradley EIP client (native and PCCC) DNP 3.0 client DNP 3.0 server GSM 1 and 3 client IEC 60870-5-101 controlled IEC 60870-5-101 controlling IEC 60870-5-104 controlled IEC 60870-5-104 controlling IEC 61850 MMS client Modbus master Modbus slave OPC tunnel ***. . . And growing***	Allen Bradley EIP client (native and PCCC) Bristal Open BSI 5.8 DNP 3.0 client DNP 3.0 server Modbus master Modbus slave WestGate master ***. . And growing***	Allen Bradley External Ovation network GE Genius GE Mark V/VI/VIe MHI Modbus master RTP IO Toshiba Wireless HART OVATION SIS
Scan type Periodic Triggered Gated	**Scan type** Periodic Triggered Exception Mapping	**Scan type** Periodic Triggered Exception Mapping Gated	**Scan type** Periodic
Time stamping Uses Ovation time	**Time stamping** Protocol time stamps	**Time stamping** Protocol time stamps	**Time stamping** Uses Ovation time
Graphic application Not applicable	**Graphic application** Allows for control directly from Ovation graphics	**Graphic application** Allows for control directly from Ovation graphics	**Graphic application** Not applicable

Ovation innovation: User group confers project-of-the-year awards

Part of the Ovation User Group experience these days is to honor and formally recognize colleagues who have demonstrated and/or pioneered controls innovations and successfully completed complex projects. Those recognized this year, only one a combined cycle, reflect the material discussed in the main article.

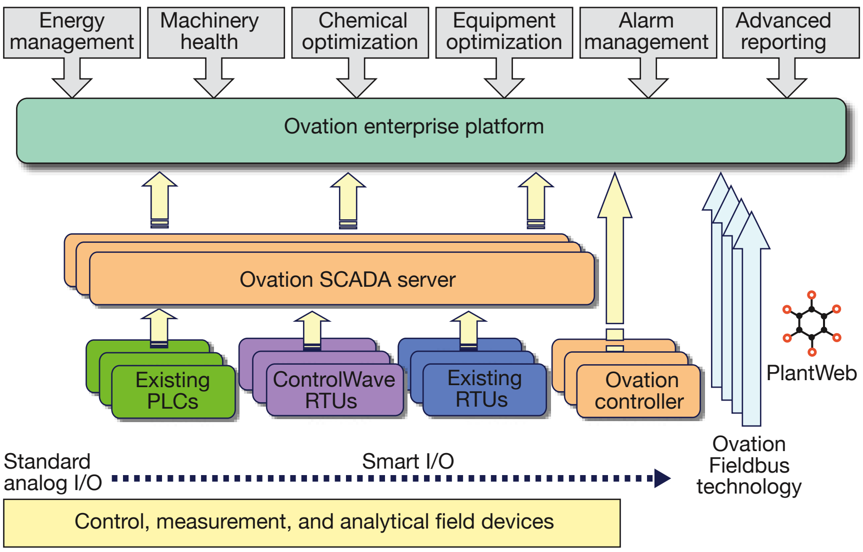
Southern Company's Plant Hammond was selected from among entrants in the powerplant category for its Unit 4 DCS replacement. An Ovation system replaced a vintage Foxboro DCS for the boiler and selective catalytic reduction (SCR) units, and Woodward Governor controls and mechanical speed control for the boiler-feed-pump turbine drives. Goals of the project included NERC cybersecurity standards compliance, better graphical interfaces and remote monitoring of the DCS graphics and logic, updated simulator software and models, higher level of M&D on transmitters and valves, and better alarm management.

ConEdison's 59th St station steam plant was also selected. The Ovation retrofit there was part of a larger conversion to natural gas for this vintage district heating facility. Controls for the station's two annex boilers (550,000 lb/hr each) and three 150,000-lb/hr packaged boilers were replaced, as were the PLC-based burner management controls on the annex boilers, and common demineralizer controls—all combined into one common platform. Included also were a high-priority alarm monitor system, Ovation process historian, security manager, EDS, SmartProcess Global Performance Advisor, and tie-back simulator.

One project cited by Robert Yeager, president, Emerson Process Management Power & Water Solutions, for the strength of its nomination, but ultimately not selected, was Constellation Energy (now Exelon) Westport Unit 5 control system upgrade. This was Emerson's first retrofit of Ovation on a Pratt & Whitney Hi-Cap system, of which only a handful are in existence. The new controls allow balancing and load sharing among the eight engines (eight gas generators, four expanders) comprising this 132-MW facility, and has improved starting and overall reliability from 50% to 100%, according to the applicants.

Other projects cited by Yeager from the pool of nominations were PENSA's San Jacinto-Tizate Geothermal Power Plant in Nicaragua, NB Power Generation Corp's Belledune Generating Station WDPF-to-Ovation migration, Xcel Energy's Sherburne County coal-yard controls replacement, WE Energies' Ovation model-based optimization at the Presque Isle Power Plant, Duke Energy's Zimmer Station turbine controls replacement, and Basin Electric Power Co-op's plant-wide automation at Dry Fork Generating Station.

Project-of-the-year for the water industry was King's County South Treatment Plant for its supervisory process control. A replacement of PLCs and Forney Corp controls with Ovation was done while the plant was on-line, with no disruption to operations.



9. Ovation SCADA solution integrates all the pieces of plant automation and knowledge management

Alstom GT9, GT11D, GT11N; and various models of Solar, Rolls Royce, and Ruston gas turbines.

Next up is the LM6000. Emerson has invested in a two-year development program around the automation of this engine and is in the commissioning stages for its beta commercial project, four LM6000s for a facility in the Midwest. To overcome a key challenge with such retrofits, embodied by the question, "How am I supported when I go away from the OEM?" Emerson has developed alliances with PSM/Alstom and Mitsubishi Power Systems Americas to provide a complementary suite of support services.

In a similar vein, Thor Honda, business development manager for steam turbine controls, discussed the many Emerson retrofits of steam turbine controls for ABB (ProControl, Advant, Turbotrol), Toshiba (TOSMAP-DS), Alstom (P320,P400), and GE (Mark V and VI), providing multiple examples in each category. Most of these legacy systems are no longer supported, not supported well, or were troublesome for plant owner/operators in the first place. Honda also addressed Emerson's rotor stress solutions, which allows for shorter startup and loading sequences than typical OEMs' loading curves. One of Honda's eye-opening graphics reveals the difference in technology evolution of a steam turbine and automation system elements (Fig 8).

It bears noting that the enhanced monitoring, diagnostics, and prognostics go hand in hand with the ability of independent service providers to support a facility at equivalent or higher quality for less money than the OEM. Much of the domain expertise and diagnostic work that would have been performed by OEM technicians, often at exorbitant labor rates, or by the OEM's remote monitoring facility, can now be done through advanced diagnostics.

It often is said that the information about the hardware is becoming more valuable than the hardware. For many of the gas turbine and CC plants which came on-line in the late 1990s/early 2000s, the control systems are reaching the end of their lives, or are becoming obsolete and not well-supported by the OEM. This is not only an opportunity to replace a control system, but to lock in aftermarket services around the hardware as well and provide a standardized platform for owner/operator organizations (Fig 9). In a big data driven world, he who controls the data wins. CCJ

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Products and services from 90 companies support new unit construction, retrofit and maintenance activities at existing facilities, and plant operations. Solutions span gas and steam turbines, HRSGs, pumps, valves, piping, cooling towers, condensers, etc

AAF International

Global leader in the field of air filtration, meeting the most demanding conditions and the toughest environmental challenges. The company's filtration, noise abatement, and other turbine products are effective, durable, and crucial to greater efficiency and performance.

ABB

Leading power and automation technologies that enable utility and industry customers to improve performance while lowering environmental impact. Turbine-automation control systems are based on ABB's field-proven control platforms that deliver safe and reliable control.

Advanced Filtration Concepts

Offers new and innovative filtration products for the GT/CC power industry. Invest to save with inlet air filters that are high efficiency, low backpressure, and long lasting. As the largest stocking distributor of industrial air filters in the West, AFC is equipped to meet your most urgent GT inlet filtration needs. Turnkey installation available.

Advanced Turbine Support

Has delivered unbiased fleet experience and superior customer service for more than a decade. Company provides users high-resolution borescope inspections, cutting edge ultrasonic and eddy-current inspections, and magnetic-particle and liquid dye-penetrant inspections in accordance with OEM Technical Information Letters and Service Bulletins.

Aeroderivative Gas Turbine Support

AGTSI offers a full range of gas-turbine and off-engine parts from the most basic to the most critical. The company is strategically located in Boca Raton, Fla, near three major airports—including Miami. AGTSI is available to its customers 24/7/365, maintaining "on call" service capability.

AGTServices

Over 200 years of combined, proven OEM engineering, design, and hands-on experience; known in the industry for its schedule-conscious, cost-effective solutions with respect to generator testing and repairs.

Allied Power Group

Earned a reputation for high-quality repairs of IGT and steam turbine components. APG specializes in hot-gas-path and combustion components from GE, Siemens/Westinghouse, and other leading OEMs. Shop staff includes engineers and expert technicians who work together to determine the best method of repair.

American Chemical Technologies

Provides state-of-the-art synthetic lubricants to the power generation industry. Founded more than 30 years ago in the US, ACT has grown to become an international supplier of value-added lubricants that provide superior benefits to equipment, the environment, and are worker-friendly.

ap+m

Largest worldwide independent stocking distributor of both aeroderivative and heavy industrial gas-turbine engine parts. As a stocking distributor of over 17,000 parts, ap+m provides internal and external engine parts as well as package parts to operators, end users, and depots worldwide.

ARNOLD Group

With more than 550 installed insulation systems on heavy-duty gas and steam turbines, company is the global leader in designing, manufacturing, and installing the most efficient and reliable single-layer turbine insulation systems.

ATCO Emissions Management

With a full line of noise control products and the company's Balanced Design Approach™ to reducing installed cost, ATCO is a single-source pro-

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vider of complete, cost-effective noise, emissions control, and heat-recovery solutions.

Bibb EAC

Multi-discipline consulting engineering firm with a focus in the power industry, Bibb has participated in a variety of projects ranging from repowering existing plants to renewable energy.

Braden Manufacturing

Braden designs and manufacturers air filtration systems and filters, inlet cooling/heating, silencing, exhaust and inlet ductwork, diverter dampers, simple cycle SCRs, expansion joints, bypass stacks, and diffusers and plenums.

Bremco

Full-service industrial maintenance contractor since 1976. Company experience in combined-cycle projects includes header, tube, and complete panel/harp replacements. We also have significant experience in liner repairs/ upgrades, duct-burner repairs, penetration seals, and stack-damper installations.

C C Jensen Oil Maintenance

Manufactures CJC™ kidney-loop fine filters and filter separators for the conditioning of lube oil, hydraulic oil, and control fluids. Our extensive know-how ensures optimal maintenance of oil systems and equipment reliability.

Camfil Farr Power Systems

A world leader in the development, manufacture, and supply of clean air and noise reducing systems for gas turbines. A correctly designed system minimizes engine degradation, leading to lower operating costs, optimum efficiency, and less environmental impact.

Chanute Manufacturing

Contract fabricator of HRSG products—including finned tubes, pressure-part modules, headers, ducting, casing, and steam drums.

Cleaver-Brooks

Complete boiler-room solutions provider that helps businesses run better every day. It develops hot-water and steam generation products aimed at integrating and optimizing the total boiler, burner, controls system to maximize energy efficiency and reliability while minimizing emissions.

Conval

Designs and manufactures high-performance valves for the world's most demanding applications, including power generation. Company has a series of power generation case studies that demonstrate the unique features and benefits of forged valves.

Cormetech

The world's leading developer, manufacturer, and supplier of catalysts for selective catalytic reduction (SCR) systems to control emissions of nitrogen oxides from stationary sources. Cormetech SCR catalysts are highly efficient and cost-effective where systems must be capable of reducing NO_x by more than 90%.

Creative Power Solutions

CPS is a group of engineering companies in the power generation and energy utilization sector. Its mission is to provide advanced, efficient, and customized technology solutions to clients ranging from OEMs to plant operators and energy consumers.

CSE Engineering

Specializes in gas, steam, and hydro turbine control system upgrades, <ITC>® HMI replacement for GE Speedtronic™ MK IV and V, gas and steam turbine field services, Woodward parts and repairs. CSE is a *Woodward Recognized Turbine Retrofit Partner.*

Cust-O-Fab Specialty Services

Provides the latest technology in exhaust plenums, exhaust ductwork, and exhaust interior liner upgrades that will drastically reduce external heat transfer, making the unit safer and more efficient and easier to operate and maintain.

Cutsforth

Our experience and innovative designs have brought best-in-class brush holders, collector rings, shaft grounding, and onsite field services for generators and exciters to some of the world's largest power companies.

DeepSouth Hardware Solutions

Spent the last seven years stockpiling surplus Westinghouse WDPF, WEStation, and Emerson Ovation control systems. Many of the items we carry are cost-prohibitive or obsolete from the OEM. Our reputation is built on fast service, low prices, and quality hardware.

DEKOMTE de Temple

Manufactures fabric and metal expansion joints which compensate for changes in length caused by changes in ductwork temperature. Axial, lateral, or angular movements can be compensated for. Company has gained a global reputation for ingenuity of design and quality of products.

Donaldson Company

Leading worldwide provider of filtration systems that improve people's lives, enhance equipment performance, and protect the environment. Donaldson is committed to satisfying customer needs for filtration solutions through innovative research and development, application expertise, and global presence.

DRB Industries

Leading supplier of gas-turbine inlet air filtration and cooling products along with turnkey installation. DRB also supplies cooling-tower parts and retrofits and evaporative media, and offers plant audits and inspections.

Dresser-Rand Turbine Technology Services

Specializes in the service and repair of heavy industrial gas and steam turbines. D-R provides aftermarket solutions for combustion, hot-gas-path and stationary and rotating components for most major gas-turbine models and frame sizes.

Dry Ice Blasting of Atlanta

Offers professional dry-ice contract cleaning services performed at your facility. Company provides a full range of dry ice blasting machines and capabilities to accommodate any size job by its team of trained, certified, and experienced operators.

EagleBurgmann Expansion Joint Solutions

Leading global organization in the development of expansion-joint technology; working to meet the challenges of today's ever-changing environmental, quality, and productivity demands. Company's flexible products are installed on equipment where reliability and safety are key factors for operating success.

ECT

Offers R-MC and PowerBack gas turbine and compressor cleaners to eliminate compressor fouling. Additionally, ECT designs specialty nozzle assemblies and custom pump skids for the proper injection of chemicals and water for cleaning, power augmentation, and fogging.

Emerson Process Management

Ovation™ control system offers fully coordinated boiler and turbine control, integrated generator exciter control, automated startup and shutdown sequencing, fault tolerance for failsafe operation, extensive cyber security features, and embedded advanced control applications that can dramatically improve plant reliability and efficiency.

Environmental Alternatives

The first company to utilize CO_2 for cleaning HRSGs, having introduced this technology to the combined-cycle power market back in the early 1990s. EAI offers the most experience in the industry for this type of work.

Eta Technologies

Consulting services for all types of GTs, especially in the areas of component manufacture, repair, RCA, component remaining life assessment and metallurgical evaluations, with extensive and unique experience on Siemens V engines. Eta also provides replacement aftermarket parts for V engines.

Falcon Crest Aviation

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.

Flow Systems

Specializes in repair and overhaul of gas-turbine accessories and steam-turbine equipment, as well as rotating equipment, utilizing modern techniques, highly skilled personnel and a state-of-the-art service facility to deliver superior quality, feasibility, and delivery to meet customer demands.

Frenzelit North America

Specializes in providing long-term expansion-joint solutions for gas-turbine exhaust applications. In addition to manufacturing superior quality expansion joints, Frenzelit also makes HRSG penetration seals, insulating materials, and acoustic pillows for silencers.

Freudenberg Filtration

Global technology leaders in the field of air and liquid filtration. The company's Viledon and micronAir brands are synonymous with high-quality filtration systems for industrial applications. Additionally, Freudenberg offers a wide-ranging service portfolio to ensure that its filter systems provide optimum benefit.

Fulmer Company

Provider of brush holders, machined components, and assemblies for the OEM, power-generation, and industrial markets. Fulmer is the largest North American manufacturer of brush-holder assemblies, offering single- and multiple-brush units for power generation OEMs and aftermarket customers.

Gas Turbine Controls

World's largest stock of GE Speedtronic circuit boards and components for the OEM's gas and steam turbines. GTC stocks thousands of genuine GE-manufactured cards for the MKI, MKII, MKIII, MKIV, MKV, MKVI, and LCI controls, as well as EX2000, Alterrex and Generrex excitation.

Gas Turbine Efficiency

Provides solutions involving the application of electrical, mechanical, and process-related equipment and components for optimizing system performance. GTE's experienced team of engineers and designers has solid industrial process backgrounds with expertise in fluid systems, instrumentation, and system controls.

GEA Heat Exchangers

From design to construction, replacement towers to spare parts, GEA has built, repaired, replaced and upgraded field-erected cooling towers for over 40 years for the power and process industries.

W L Gore & Associates

Focuses on optimizing gas-turbine performance via the application of hydrophobic, membrane-based, HEPA inlet air filters, which eliminate the need for off-line washes while dramatically reducing or eliminating the power-output and heat-rate degradations that result from turbine fouling.

GP Strategies

Works with utilities and independent power producers worldwide to increase profitability by maximizing plant availability and generating capacity, while minimizing risk. Company developed EtaPRO™ performance and condition-monitoring technology and GPiLEARN™ web-based training technology.

Groome Industrial Service Group

Offers a variety of SCR and CO catalyst cleaning and maintenance services nationwide and has formed strategic alliances with industry experts and catalyst manufacturers to ensure that Groome offers the most widely supported, comprehensive, turnkey service available.

GTC Services

Field engineering company offers gas-turbine owners and operators worldwide "Total Speedtronic Support." Engineers have decades of experience servicing and troubleshooting all GE Speedtronic systems.

Haldor Topsoe

Our air pollution technology includes a series of unique catalysts for Selective Catalytic Reduction (SCR) systems for the control of nitrogen oxides (NO_X), and the reduction of carbon monoxide (CO) and volatile organic compounds (VOCs), from stationary and mobile sources.

Hilliard

The HILCO® Division cost-effectively brings fluid-contamination problems under control and engineers a full-range of filters, cartridges, vessels, vent mist eliminators, transfer valves, reclaimers, coolant recyclers and systems, and membrane filtration systems.

HRST

Provides HRSG, conventional boiler, and powerplant technical services and products. Company specializes in HRSGs and waste-heat boilers. HRST engineers, technicians, and designers perform inspection, analysis, and design upgrades to help clients avoid and solve boiler problems.

Hydro

Engineered solutions enable combined-cycle plants to achieve pump reliability and reduced O&M costs. As the largest independent pump rebuilder, Hydro works hand-in-hand with pump users to optimize the performance and reliability of their pumping systems.

Hy-Pro Filtration

Provides innovative products, support, and solutions to solve hydraulic, lubrication, and diesel contamination problems. Company's global distribution and technical-support networks enable customers to get the most out of their diesel, hydraulic, and lube-oil assets. ISO 9001 certified.

JASC

Engineers and manufactures actuators and fluid-control components for power generation, aerospace, defense, and research applications to improve operational capability and performance.

Johnson Matthey

Worldwide leader in the development and manufacture of catalysts for the reduction of NO_x, CO, VOC, NH_3, and particulate emissions from gas turbines, boilers, stationary reciprocating IC engines, and industrial processes.

KnechtionRepair Tools

Manufactures tools designed to make thread repairs to both the female and male ends of cross-threaded compression fittings. In most cases, the repair will be accomplished without removing the tube from the system. This saves the O&M tech time and avoids additional downtime.

Kobelco Compressors America

Provides robust, high-efficiency fuel-gas compressors for use with all major types of gas turbines—including GE, Mitsubishi, Alstom, Siemens, Rolls-Royce, and Solar. Over 300 of the company's screw-type compressors have been supplied for gas turbines.

Liburdi Turbine Services

Advanced repairs employ the latest technologies and are proven to extend the life of components for all engine types. Company specializes in high-reliability component repairs and upgrades for blades, vanes, nozzles, shrouds, combustors, and transitions.

M & M Engineering

Provides failure analyses and related services to industrial and insurance-company clients. M&M's expertise includes corrosion in boilers, steam turbines, generators, combustion turbines, deaerators, feedwater heaters, and water and steam piping.

Mechanical Dynamics & Analysis

One of the largest turbine/generator engineering and outage-services companies in the US. MD&A provides complete project management, overhaul, and reconditioning of heavy rotating equipment worldwide.

Membrana, a Polypore company

Market-leading producer of microporous membranes and membrane devices used in healthcare and industrial degassing applications. The Industrial & Specialty Filtration Group manufactures Liqui-Flux® ultrafiltration and microfiltration modules as well as Liqui-Cel® membrane contactors.

Moran Iron Works

Global fabrication company committed to providing efficient processes, flexibility, and adaptability to ensure projects are completed on schedule. Moran specializes in one-of-a-kind fabrication and replacement of critical turbine components.

NAES

The energy industry's largest independent provider of operations, construction, and maintenance services—including equipment retrofit and repair, onsite turbine inspection/overhauls, and staffing solutions.

National Electric Coil

Leading independent manufacturer of high-voltage generator stator windings with expertise in design and manufacturing of stator windings for any size, make, or type of generator. This includes diamond coils, Roebel bars—including direct cooled, inner-gas, and inner-liquid cooled bars—and wave windings.

Natole Turbine Enterprises

Provides gas-turbine consulting to the utility, cogeneration, IPP, and pipeline gas-turbine markets. These services are directed toward component repair, rotor refurbishment, overhaul, upgrading, and reapplication.

NEM Energy

A leading engineering company operating globally in the field of steam generating equipment. NEM supplies custom-made solutions regarding industrial, utility, and heat-recovery steam generators for power generation and industrial applications.

Nooter/Eriksen

World's leading independent supplier of natural circulation HRSGs behind gas turbines and a single-source supplier of custom-designed heat-recovery systems. NE's annual sales volume includes HRSGs for combined-cycle powerplants whose output exceeds 8 MW.

On-Site Equipment Maintenance

Solid reputation in the power industry for decades as the industry leader in rebuilding critical and severe service control valves, AOVs, MOVs, and turbine valves. Company also specializes in boiler feed pumps, circ-water pumps, condensate pumps, fuel pumps, and rotating equipment.

Pneumafil

Major air-inlet filter-house supplier to all major turbine manufacturers for over 45 years. Company manufactures certified, high-efficiency filtration products for all brands, pulse style or static style inlet housings, to ensure maximum turbine output and efficiency.

Powergenics

Leading supplier of industrial electronic circuit-card and power-supply repairs to industrial and power generation customers. Company provides a very high-quality repair at a substantial cost savings from the OEM and other competitors while maintaining a warranty service second to none.

Praxair Surface Technologies

Leading global supplier of surface-enhancing processes and materials, as well as an innovator in thermal spray, composite electroplating, diffusion, and high-performance slurry coatings processes. Company produces and applies metallic and ceramic coatings that protect critical metal components.

Precision Iceblast

World leader in HRSG tube cleaning. PIC cleans more HRSGs than any other ice blasting company in the world. It ensures that HRSGs operate efficiently by providing the cleanest boiler tubes possible.

Proco Products

Supplies rubber expansion joints to the power industry in sizes ranging from 1 to 120 in. ID. Proco keeps joints up to 72 in. ID in stock at its Stockton (CA) warehouse and works through an agent/distributor network to supply products to combined-cycle plants.

PSM—an Alstom company

Full-service provider to gas-turbine equipped generating plants, offering technologically advanced aftermarket turbine components and performance upgrades, parts reconditioning, field services, and flexible Long Term Agreements (LTAs) to the worldwide power generation industry.

PW Power Systems

Provides competitive, efficient, and flexible gas-turbine packages rated from 25 to 120 MW. PWPS offers a full range of maintenance, overhaul, repair and spare parts for other manufacturers' GTs with specific concentration on the high-temperature F-class industrial machines.

Rentech Boiler Systems

International provider of high-quality, engineered industrial boiler systems. Rentech is a market leader in providing HRSGs for cogeneration and CHP plants. It is in its second decade of designing and manufacturing high-quality custom boilers—including HRSGs, waste-heat boilers, fired packaged boilers, specialty boilers, and emissions control systems.

Rockwell Automation

Helps power producers navigate the technological, engineering, and design challenges they face in implementing new or upgraded control systems. Company offers integrated control, power, safety, and information solutions in one open, scalable architecture for complete plant-wide control.

FIND A VENDOR, FIX A PLANT

Sargent & Lundy

Provides complete engineering and design, project services, and energy business consulting for power projects and system-wide planning. The firm has been dedicated exclusively to serving electric power and energy-intensive clients for more than 120 years.

Sentry Equipment

Engineers, manufactures, and services components for collecting representative samples of steam, water, gas, liquid, slurry, and bulk solids. This enables analytical and operational professionals to gain samples safely and simply, and with repeatable results.

Sound Technologies

Provides engineered silencers and systems for new and replacement gas-turbine applications—including turbine inlet silencing, turbine enclosures, bypass systems, and HRSG inlet shrouds and stack and vent silencers.

SSS Clutch Company

Clutches enable operators to disconnect generators from simple-cycle turbines for synchronous-condenser service. Clutches also find application in CHP plants and in single-shaft combined-cycle facilities where operating flexibility is beneficial.

Stellar Energy

Leading provider of energy plant systems, including turbine inlet-air chilling and TIAC with thermal-energy storage, district cooling, modular utility plants, and CHP. Steller offers a complete range of in-house analysis, design, fabrication, installation, startup and commissioning, and maintenance.

Strategic Power Systems

Provides products and services focused on capturing powerplant operational and maintenance data to develop reliability metrics and benchmarks for end users—including some of the most recognized organizations in the global energy market.

Sulzer Turbo Services

The leading independent and most technically advanced and innovative services provider for all brands of mechanical and electromechanical rotating equipment. The company also manufactures and sells replacement parts for gas turbines, steam turbines, compressors, motors, and generators.

Thor Precision

Value-added service center provides reverse-engineered rotor bolting for the gas-turbine aftermarket—specifically for Frame 3, 5-1, 5-2, 6B, 7E, 9E engines—including compressor, turbine, marriage, and load-coupling hardware.

Turbine Controls & Excitation

TC&E is an engineering consultation firm focused on turbine and generator controls services. Services include emergency troubleshooting, maintenance support, and equipment upgrades on GE MK I-VIe controls, exciters, and LCIs.

Turbine Generator Maintenance

Provides turnkey field service maintenance for all turbine/generator components. TGM services the turbine, generator, exciter, control systems, and auxiliaries either individually or in any combination. Its service area includes the US, Caribbean, and South America.

Turbine Technics

Global distributor of parts and components for industrial and marine turbine engines, providing support for GE LMS100, LM2500, LM5000, LM6000 as well as P&W GG8/FT8, GE Frame 3/5/6/7/9, and Rolls Royce turbines.

TurboCare

Comprehensive product and service solutions for rotating equipment manufactured by all major OEMs—including component repair, equipment refurbishment, system retrofits, engineering, and replacement parts.

Universal Plant Services

Specializes in the maintenance, repair, and overhaul of gas and steam turbines, centrifugal and reciprocating compressors, as well as all rotating equipment, with qualified millwright and field machining specialists.

URS

Leading provider of engineering, construction, and technical services offers a full range of (1) program-management; (2) planning, design and engineering, (3) systems engineering and technical assistance, (4) construction and construction management, (5) O&M; and (6) decommissioning and closure services.

Victory Energy

Offers all types of industrial boilers: watertube, HRSG, firetube, and solar-powered units. Company provides unprecedented support with its rental boilers, spare parts, field service, and auxiliary equipment—including water-level devices, economizers, stacks, expansion joints, and ductwork.

Wabash Power Equipment

Full range of power equipment and services including: packaged boilers, rental boilers, and electric generators; diesel/generators and gas and steam turbine/generators; pulverizers and accessories; auxiliary equipment; spare parts.

Wood Group GTS

Leading independent provider of services and solutions for the power and oil and gas markets. These services include powerplant engineering, procurement and construction, facility O&M, repair and overhaul of gas and steam turbines, pumps, compressors, and other high-speed rotating equipment.

Young & Franklin

Premier fuel control supplier for combustion turbines for both long-term hydraulic solutions and, more recently, innovative all-electric controls solutions. Product scope supports natural gas, liquid, syngas, and alternative fuels as well as providing air controls to provide proper fuel to air mixtures.

Zokman Products

Distributor of ZOK27 and ZOKmx gas-turbine compressor cleaning detergents. ZOK27 is a single cleaner and inhibitor in one that cleans and protects the engine—and also inhibits corrosion. ZOKmx is a power cleaner formulated to replace solvents providing exceptional cleaning without the health and environmental risks associated with solvents.


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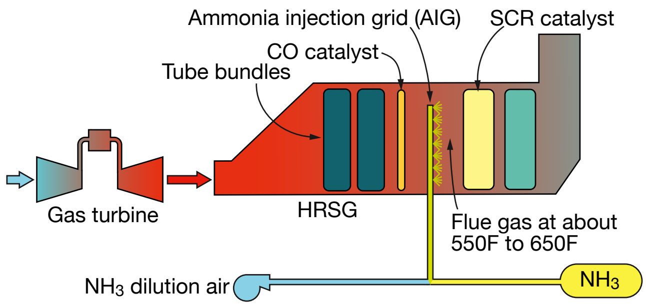
Take control of your catalyst management

By **L Muzio** and **R Smith,** Fossil Energy Research Corp, and **J Baker** and **J Perez**, Riverside Public Utilities

Combined- and simple-cycle gas turbine (GT) systems typically rely on oxidation and SCR catalysts to reduce CO and NO_x emissions, respectively. In a combined cycle, GT exhaust gas usually flows through one or more HRSG tube banks before entering the CO catalyst (Fig 1). Ammonia, a reagent, is injected downstream of the CO catalyst and ahead of the SCR catalyst, where it combines with oxides of nitrogen in the exhaust gas to form nitrogen and water vapor.



1. CO and SCR catalyst arrangement for a typical combined cycle has no diffuser vanes, perforated plates, or tempering air downstream of the gas turbine. A uniform NH_3/NO_x profile at the catalyst inlet is critical to achieving desired SCR performance in terms of NO_x reduction and ammonia slip

An important O&M activity is management of the CO and SCR catalysts. Theoretically, a catalyst does not wear out with use; rather, it just helps a reaction take place. However, contaminants in the exhaust gas poison the catalysts over time and reduce their effectiveness. Catalyst management involves systematically tracking catalyst performance both to (1) ensure continued environmental compliance, and (2) provide timely information to guide catalyst purchases and replacements.

This article discusses how CO and SCR catalysts should be managed and how you as an owner/operator can take control of the management process by performing tests within the unit.

SCR catalyst management

Catalyst management for a combined-cycle SCR system entails tracking key parameters so you know when the catalyst must be changed. These parameters are catalyst activity (K, m/hr) and reactor potential (RP, dimensionless). The first determines how well a catalyst is performing regarding NO_x reduction. While deactivation is less severe in a combined-cycle SCR than it is in a coal-fired unit, it still occurs.

Typical poisons in a combined-cycle SCR include sodium and phosphorous. The former may enter the gas stream from (1) water injected into the engine for NO_x control or power boost, (2) off-spec water used in the production of aqueous ammonia, and (3) ambient sources for units located near the coastline. Phosphorous comes from lube oil that finds its way into the GT exhaust stream.

In an SCR reactor, if excess ammonia is present—that is, NH_3/NO_x > 1—NO_x reduction is calculated using the following equation:

Eq 1: $\Delta NO_x = (1 - e^{-K/Av})$,

where Av is the area velocity (exhaust-gas flow rate divided by the total amount of SCR catalyst area):

Eq 2: $Av = Q \div V_{cat}As$.

Note that Equation 1 is used to measure SCR catalyst activity in a laboratory.

In conducting a laboratory activity test on SCR catalyst, a specified volume of catalyst is exposed to a known gas flow rate. The gas can be actual GT exhaust gas, or simulated gas at a given temperature and inlet NO_x level. Ammonia then is injected at the sample inlet at a high NH_3/NO_x ratio to provide excess ammonia at the catalyst surface.

Depending on the laboratory, the ammonia injection rate may be NH_3/NO_x = 1.0, 1.2, or 1.5. NO_x reduction is measured across the catalyst sample and the activity, K, is determined from a rearrangement of Equation 1 based on the maximum NO_x reduction measurement and gas velocity through the catalyst. It is presented this way:

Eq 3: $K = -Av \ln(1 - \Delta NO_x)$.

While the foregoing laboratory process seems simple, it's not quite so. For instance, what conditions should one use to determine the activity in the laboratory (gas composition, temperature, area velocity, etc) and how should the results be reported? There are established testing protocols for coal SCR catalyst—such as the European VGB guidelines and EPRI's SCR catalyst testing protocol—but none for GT SCR catalyst.

To illustrate: Table 1 summarizes conditions used by five GT catalyst testing laboratories and how the results are reported. Note that there is no consistency in the test conditions

Table 1: Typical gas-turbine SCR laboratory test procedures

	Test conditions				What is reported
Laboratory	Av, m/hr	T, F	NO_x, ppm	NH_3/NO_x	
A	Av>FS	FS	Unspecified	1.0/1.2	K/K_{new} or K/K_{min}
B	FS	FS	FS	Varies	ΔNO_x at NH_3 slip limit
C	FS	FS	FS	0.97-1.2	K/Ko at NH_3/NO_x = 1.0 ΔNO_x and NH_3 slip at each NO_3/NO_x
D	25	608	200	1.2	K
E	35	FS	FS	1.5	K

FS = Full scale

used. There are variations in the Av used for the test, the temperature, and the NH_3/NO_x ratio used for determining the activity, K.

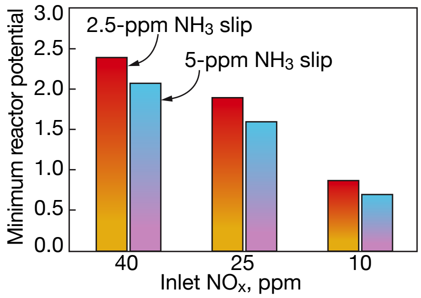
How the results are reported also varies. Laboratories C, D, and E either report the actual activity K, or provide sufficient data to calculate K. Laboratory A reports a relative activity (either K/K_{new}, or K/K_{min}). Laboratory B differs too, reporting the level of NO_x reduction that the catalyst achieves at the ammonia slip limit.

This lack of an established testing protocol can make catalyst management difficult. If an owner/operator decides to change laboratories, can the data from the old and new laboratory be used together? For instance, if you have a history of just the relative activity, K/K_{new}, then switch to a laboratory that reports K, how can these data sets be merged since the original laboratory did not report K_{new}?

Reactor potential. Although catalyst activity is important, the key parameter for determining SCR performance is the reactor potential, RP—basically, the activity multiplied by the total catalyst surface area per unit of exhaust gas. Given an initial NO_x level, required level of NO_x reduction, and limit on NH_3 slip, one can calculate the minimum RP that a reactor needs to achieve this given performance goal. This is expressed mathematically as:

Eq 4: $RP_{min} = K \div Av = f(NO_x\text{-inlet}, \Delta NO_x, \text{and } NH_3 \text{ slip})$.

Fig 2 shows how the minimum RP varies for two levels of required NH_3 slip and varying inlet NO_x, assuming an outlet NO_x level of 5 ppm must be achieved. RP is important because it reflects the effects of both catalyst activity and area velocity. Several factors can influence area velocity calculations. For example, insulation accumulation on the catalyst surface will reduce the available catalyst surface area and, consequently, RP.



2. Minimum reactor potential decreases as inlet NO_x concentration decreases and ammonia slip increases. Data are for 5 ppm outlet NO_x

Variations in GT exhaust-gas flow also can increase or decrease RP. Thus, from an overall operating perspective, the RP determines SCR performance—not just catalyst activity. Ultimately, SCR catalyst management entails (1) knowing the minimum RP needed to achieve the necessary performance, and (2) monitoring the RP over time. Other factors, such as the NH_3/NO_x distribution entering the catalyst are also important. Access background material by scanning the QR code provided with your smartphone or tablet.

Measure RP in-situ. While sending samples to a laboratory for activity measurements historically has been a key step in catalyst management, it is no longer necessary. As mentioned earlier, there are numerous shortcomings associated with laboratory analysis. Today, an owner/operator can take control of catalyst management with CatalysTraK®, a system that measures catalyst activity and RP in-situ.

Fig 3 provides an overview of the CatalysTraK approach for gas-fired turbine applications. Similar to the laboratory approach for SCR catalyst, NO_x reduction is measured across a small cross section ("test section") of the catalyst bed. A small supplemental ammonia injection grid (AIG) is permanently mounted upstream of the test section (Fig 4).

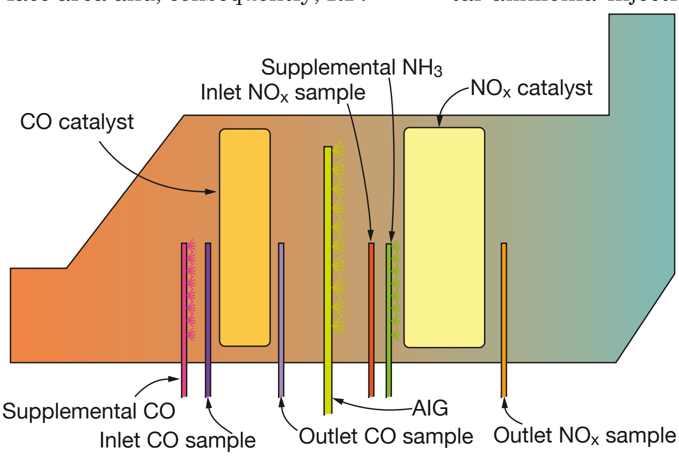
Additionally, an inlet gas sampling probe is installed directly upstream of the AIG, and an outlet gas sampling probe is installed immediately downstream of the catalyst bed at the test section. The supplemental AIG is used to increase the NH_3/NO_x level and provide excess ammonia across the catalyst test section. The RP calculation then is based on the maximum NO_x reduction measured across this catalyst test section.

CatalysTraK was developed for coal-fired SCRs. These systems are characterized by multiple catalyst layers, where the total RP is the sum of the reactor potentials of the individual layers. With the lower RP of the individual layers, it is relatively easy to make an RP measurement across a catalyst layer.

One issue related to the application of CatalysTraK to a GT SCR is that these systems have a single layer of catalyst and it contains all of the reactor's RP. Thus, when catalyst is relatively new, the measured NO_x reduction across a layer of GT catalyst at NH_3/NO_x > 1 can be greater than 99%.

This can make it difficult to accurately determine the RP. For instance, with an inlet NO_x level of 25 ppm, Fig 5 shows the expected measurement of the outlet NO_x as a function of the RP. The dashed line in the illustration is RP_{min} (2.3) for a combined cycle starting at an inlet NO_x of 25 ppm with an outlet NO_x of 2.5 ppm and an ammonia slip limit of 5 ppm.

When the catalyst is new, the RP for the system may be about 6, significantly higher than the 2.3 minimum. For the "new" condition, the outlet NO_x measured with the CatalysTraK system can be less than 0.2 ppm. However, Fig 5 shows that as the catalyst ages and RP_{min} is approached, the CatalysTraK measurement will exceed 2 ppm—a level that is easily measured.



3. Catalyst activity and reactor potential are measured in-situ at Clearwater Cogen

4. Supplemental AIG assembly installed at Clearwater Cogen


Kellstrom
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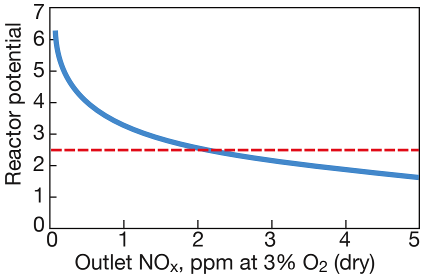
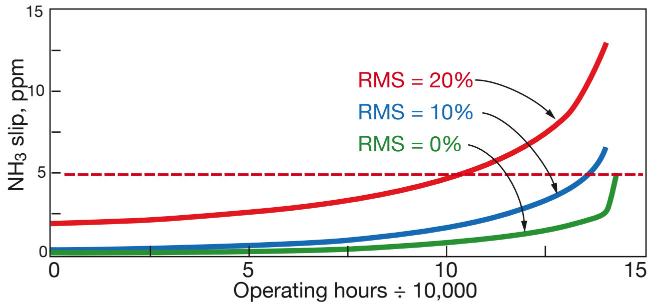


5. Outlet NO_x measurement as a function of reactor potential for an inlet NO_x level of 25 ppm. Dashed line is RP_{min} for a combined cycle starting at an inlet NO_x of 25 ppm, outlet NO_x of 2.5 ppm, and ammonia slip limit of 5 ppm. When the catalyst is new, system RP may be about 6, compared to the 2.3 RP_{min}



6. How NH_3 slip varies with operating hours for different NH_3/NO_x distributions at the catalyst inlet

The bottom line: Early in a catalyst's life, the CatalysTraK measurement may have a higher degree of uncertainty associated with RP, but at that point in a catalyst's lifecycle it is not critical that the RP be precise.

As the catalyst ages, the shape of the deactivation curve becomes better defined. In fact, one of the advantages of CatalysTraK is that a larger data set can be acquired, particularly towards end-of-life when performance changes—as evidenced by increasing NH_3 slip—occur more rapidly.

Field validation. CatalysTraK SCR tests recently were conducted at the Clearwater Cogeneration Plant, owned and operated by the City of Riverside (Calif) Public Utilities. Two sets of measurements were taken as shown in Table 2. For Test 1 the inlet NO_x was a little lower than for Test 2 (23.9 versus 25.6 ppm_c). Supplemental NH_3 was injected until the outlet NO_x leveled out at 0.183 ppm_c and 0.235 ppm_c for Tests 1 and 2, respectively. These latter levels then were used to calculate the RP values of 4.9 and 4.7.

The average measured RP of 4.8 is substantially higher than the 2.3 minimum RP value. While there can be some uncertainty in the absolute level of the RP because the outlet NO_x during the measurement was low (about 0.2 ppm), the SCR catalyst is clearly very active. However, as was shown in Fig 5, the outlet NO_x with the supplemental NH_3 injection will increase to more than 2 ppm as end-of-life approaches.

Since the as-installed catalyst RP was unknown, the remaining catalyst life was estimated by assuming a fairly aggressive deactivation rate of 5% per 10,000 hours of operation. Also, as mentioned previously, the minimum RP = 2.3 assumes a good NH_3/NO_x distribution entering the catalyst.

Typically a good NH_3/NO_x distribution for a gas turbine SCR system would be characterized by an RMS < 10%. When the Clearwater Cogeneration AIG was recently tuned, the RMS was about 20%. Fig 6 shows how ammonia slip varies with operating hours (zero being when the CatalysTraK measurements were made) for different NH_3/NO_x distributions entering the catalyst. The distributions assume 90% NO_x reduction from an inlet NO_x level of 25 ppm). Specifically:

- RMS = 0%: At 143,000 hours, RP reaches the minimum of 2.3. Here, the NH_3 slip increases to the 5-ppm limit. Beyond this point there is insufficient activity to reach 2.5 ppm of NO_x.
- RMS = 20%: Slip of 5 ppm is reached at 100,000 hours of operation (RP = 2.3). This NH_3/NO_x maldistribution significantly reduces catalyst life.

While the catalyst management can be performed just using the reactor potential, RP, it is of interest to also look at the catalyst activity, K, based on the in-situ results. The area velocity for these tests was calculated to be 13.9. The in-situ measurements, along with the calculated Av, yield a catalyst activity of 66.5 m/hr (K = RP × Av).

There is some uncertainty in the absolute activity because the slope of RP versus the outlet NO_x level is quite steep at such high-activity values (refer back to Fig 5). Thus, if the measured outlet NO_x concentration is off by ±0.1 ppm, the calculated activity can range from 62.3 to 76.5. The precision increases as the catalyst ages. But the fact remains that CatalysTraK is able to characterize the state of the SCR catalyst using some fairly simple in-situ measurements.

Table 2: CatalysTraK SCR test results

Test	Inlet NO_x, ppm**	Outlet NO_x*, ppm**	dNO_x, %	RP
1	23.9	0.183	99.23	4.9
2	25.6	0.235	99.08	4.7

*Supplemental NH_3 (NH_3/NO_x>>1) **At 15% O_2

CO catalyst testing

As with SCR catalyst, CO catalyst performance also degrades over time. Historically, samples are taken from the CO catalyst bed (either specifically designed test samples, or core-drilled samples from the actual bed). In the laboratory they are typically tested at the same space velocity (exhaust gas flow rate divided by CO catalyst volume). The test involves just measuring the amount of CO oxidation that occurs across the sample.

Why use a laboratory to make this measurement? Why not just measure the oxidation across the actual CO catalyst bed while it is operating? This also was done during the recent Clearwater Cogeneration tests. An inlet and outlet probe pair was located across a local region of the CO catalyst and the amount of CO oxidation was measured.

Four sets of CO measurements were made across the catalyst. These results, presented in Table 3, show the oxidation of CO across the CO catalyst at the test location was quite high, averaging 96.7%.

Table 3: CatalysTraK CO oxidation results

Test	Inlet CO, ppm*	Outlet CO, ppm*	dCO, %
1	34.2	1.2	96.5
2	38.9	1.2	97.0
3	31.6	1.1	96.6
4	31.3	1.0	96.7
Average			96.7

*At 15% O_2

Wrap up. Historically, laboratory tests have been used to monitor the performance of both SCR and CO catalysts over time. The lack of a testing protocol, particularly for gas-turbine SCR catalyst layers, causes problems with inter-laboratory comparisons. Recent tests at the Clearwater Cogeneration Plant showed both SCR and CO catalysts can easily be characterized in-situ. The in-situ technique is simple. It can be done easily during an annual compliance test, does not require an outage, and provides an opportunity to obtain a more comprehensive data set. CCJ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Mitigate failures with tighter control of water chemistry, better materials

By Kevin J Boudreaux, Nalco Power

Rotor air coolers (RACs) are installed in most 501F- and G-class combined cycles to reduce the temperature of compressor discharge air used for rotor cooling. They can be air-to-air heat exchangers (fin-fan coolers) or water can be used as the cooling medium (Fig 1). Siemens Energy Inc often refers to its air-to-water exchangers as kettle boilers; Mitsubishi Power Systems Americas Inc calls them TCA (turbine cooling-air) coolers.

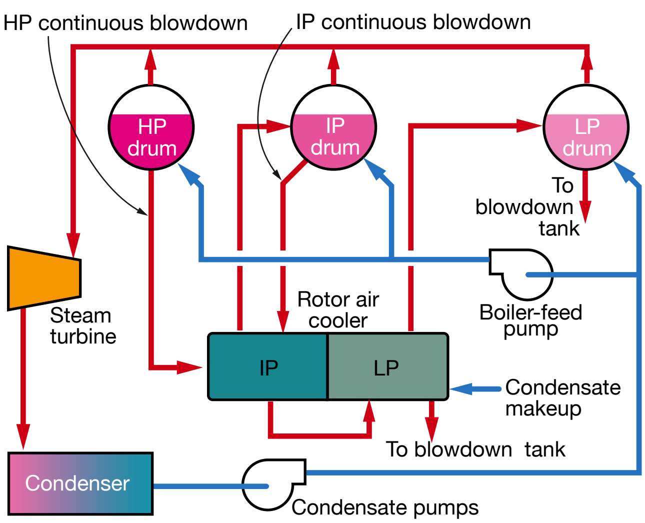
Air-to-water exchangers are built to Section 8 of the *ASME Boiler and Pressure Vessel Code*. Their advantage over fin-fan coolers is that heat is captured by the system, not rejected to atmosphere. Result is a small improvement in plant performance.

All 24 engines in the Siemens 501G fleet rely on kettle boilers for rotor air cooling. Three of these RACs have experienced failures in the low-pressure (LP) section, nine in the intermediate-pressure (IP) section (Sidebar 1). One 2 × 1 combined cycle in the Southwest reported failures in the IP sections of both RACs. Data indicate that all IP RAC failures have occurred between the tube and tubesheet at the seal weld. More importantly, the failures have occurred on the tubesheet and on the weld material, not the tubes themselves.

Industry consensus is that the root cause of the failures is chloride stress corrosion cracking (SCC), based on metallurgical failure analyses. The failures have led to costly downtime and repairs and have generated much discussion at industry meetings regarding corrective action. The OEM's initial response to the failures was a suggestion to adjust RAC operating chemistry.

This article is a compilation of Siemens G-fleet experience with the goal of helping owner/operators to:

- Better understand the chloride SCC mechanism.
- Determine if there are other extraneous factors propagating SCC.
- Review OEM chemistry recommendations.
- Identify other possible corrective actions for mitigating RAC failures.



1. How rotor air coolers are integrated into the steam/water circuit (left)

Stress corrosion cracking in RACs

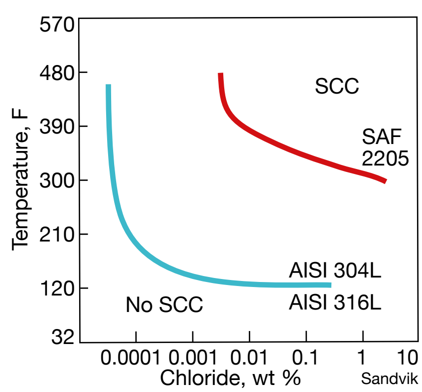
According to *The Nalco Guide to Cooling Water System Failure Analysis* (Ref 1; scan the QR code with your smartphone or tablet for more information), SCC is defined as failure by cracking under the combined action of corrosion by specific corrodents and stress. Industry experts generally agree the following three elements must be present for SCC to occur: (1) metallurgy susceptible to stress corrosion cracking by the specific corrodent, (2) elevated concentration of the corrodent, and (3) high stresses. The specific corrodent that most commonly causes SCC in Types 304 and 316 stainless steels is a chloride solution.

http://www.nalco.com/document-library/4406.htm

Ref 1

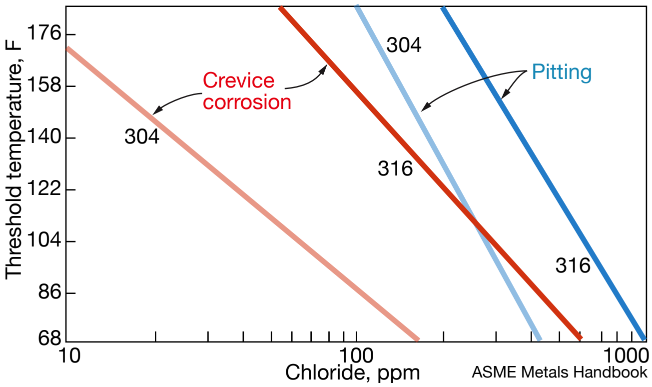
Metallurgies and chloride. Fig 2 shows the chloride levels required to initiate SCC at various temperatures. Also, it illustrates how that potential varies based on specific metallurgies. In regard to SCC susceptibility, Type 304, most commonly used to construct RACs, exhibits the least amount of resistance when compared with other

2. Chloride level required to initiate stress corrosion cracking at various temperatures (right)



metallurgies appearing in the chart. Note that the chloride concentrations in Fig 2 represent bulk water concentrations and do not take into consideration the importance of concentrating mechanisms such as evaporation and ion concentration cell formation within crevices and beneath occlusive deposits.

Fig 3 shows the difference in bulk-water chloride limits for pitting versus crevice corrosion. As the figure reveals, 100 ppm of chloride in the bulk water may be acceptable to protect against general pitting corrosion at a particular temperature, but that concentration at the same temperature could cause corrosion if a crevice were present. Reason: Contaminants can concentrate within the crevice, and be orders of magnitude higher than in the bulk water. Crevice corrosion is particularly important given the nature of RAC failures.



3. Bulk-water chloride concentration required to initiate crevice corrosion is less than that needed to initiate pitting (left)

High stresses can be applied or residual. Examples of an applied stresses can be tensile, thermal expansion, service loads. Applied stresses can be continuous, intermittent, and/or present only during plant load transients. Residual stress typically is created by cold-working during manufacturing or by welding practices that might benefit from change. Heat treatment can help reduce residual stresses created by welding, but the use of this practice can be limited, according to Ref 1. It is important to note that residual stresses can approach the yield stress. Whatever the stress may be, its presence helps to initiate and propagate SCC when the other necessary elements are present.

Impact of oxygen and high temperature. In addition to the three variables previously identified as necessary to induce SCC, research cited in Ref 1 indicates other elements also must be present—including dissolved oxygen and temperatures above about 140F. The RAC operating temperature, approximately 840F on the air side and more than 450F on the water side, is above the 140F minimum critical temperature, and thus is well within range for SCC to occur.

http://www.powermag.com/layup-practices-for-fossil-plants/

Ref 2

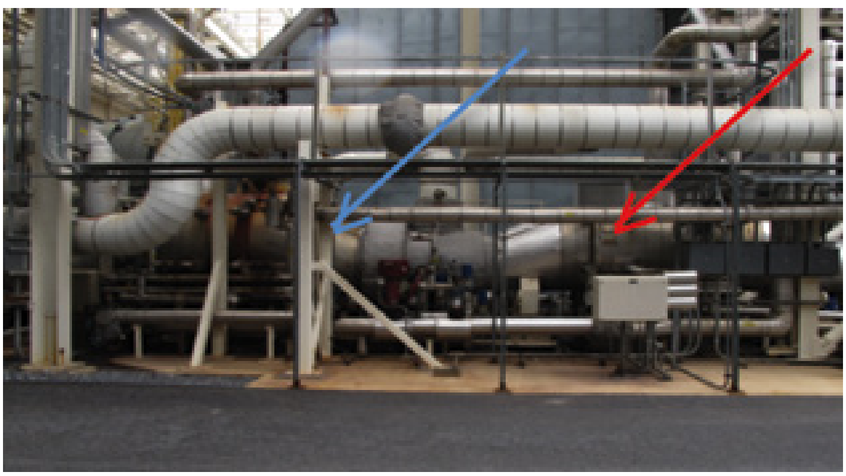
1. How air-to-water RACs are designed and work

The rotor air cooler (RAC) integrated into combined-cycle systems powered by Siemens 501G engines is a single-pass, shell-and-tube, air-to-water heat exchanger—often referred to as a kettle boiler. It reduces the temperature of a portion of the compressor air flow to cool the rotor, blades, and vanes in the gas turbine.

Water is on the shell side of the RAC, compressed air flows through the tubes. The heat exchanger has an intermediate-pressure (IP) section (blue arrow in Fig A) and a low-pressure (LP) section (red arrow). IP water cascades to the LP section as shown in text Fig 1. Tubes and tubesheets typically are made of Type-304 stainless steel. The tubes are rolled into the tubesheets and welded to create a tight seal between the rotor air and the cooling water. Fig B shows the single-pass flow path for the compressed-air circuit.

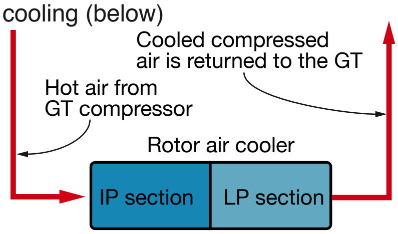
As shown in text Fig 1, blowdown lines from the HRSG's HP and IP steam drums are integrated into the RAC circuitry. Steam produced by flashing is returned to the IP and LP drums. Condensate is added to the LP RAC, as necessary, to control its water level. Note that blowdown from the LP RAC is the final blowdown for the HRSG; therefore, level and blowdown control of the drums and RAC are both critical and challenging, considering the varying water chemistry requirements throughout the boiler.

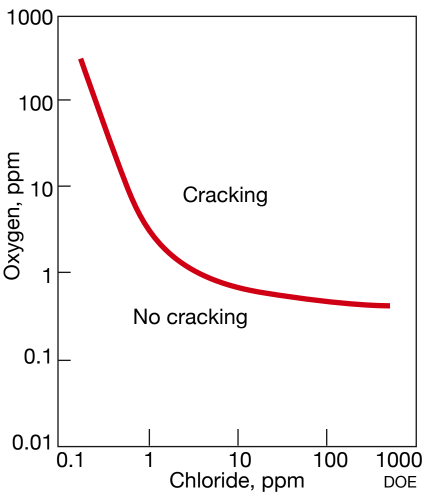
Because of the HRSG configuration, cycles of concentration are not the plant's friend when considering chemistry. Any contaminant introduced with the condensate or makeup water concentrates up in the drums and then in the RAC. Given the complexity of the HRSGs associated with 501Gs, as well as the general lack of instrumentation, it is very difficult to determine the amount of HP and IP blowdown flowing to the IP RAC and the contaminant concentrations present in each of those streams. This obviously makes RAC chemistry control extremely challenging.



A. Rotor air cooler, or kettle boiler, is found in the majority of plants powered by 501F and 501G gas turbines (left)

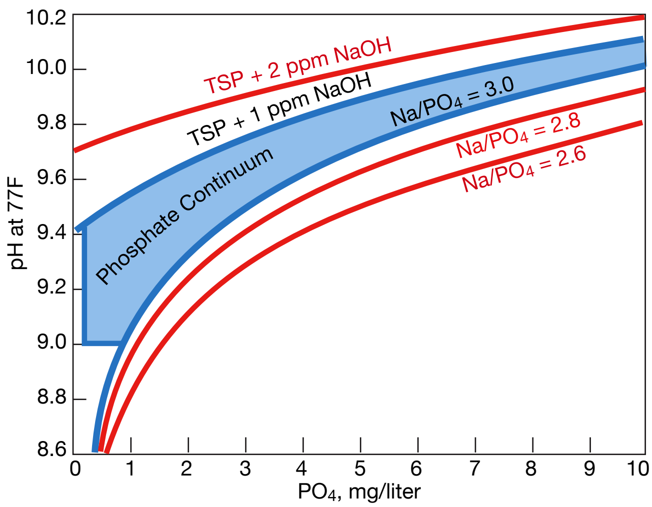
B. Hot air is extracted from the compressor, cooled in the kettle boiler (shown left) or in an air-to-air heat exchanger, and used for rotor cooling (below)





4. Relationship between oxygen and chloride levels on SCC is presented for a temperature range of 470F to 500F (left)

5. Phosphate Continuum Control Chart helps in maintaining tight control of drum chemistry. Minimum level of PO_4 is greater than 0.2 mg/liter



A DOE report adds that as temperatures increase, the time to metal failure from SCC decreases (Ref 4). While operating temperature appears to be a significant and understood factor in RAC failures, it is the influence of dissolved oxygen on SCC that has raised questions. The DOE report also says that when oxygen levels are maintained at low residuals, the potential for SCC is reduced.

Fig 4, from that report, highlights the relationship between oxygen and chloride levels and their influence on SCC. The temperature range for the data set is 470F-500F, much lower than the RAC's 840F operating temperature. Recall that as the temperature increases, so does the potential for failure from SCC.

Because RAC's are expected to operate with very little oxygen in the bulk water, less than 10 ppb in the feedwater if the HRSG follows EPRI AVT(O) guidelines, one would expect there would not be enough oxygen available to allow SCC to occur under normal operating conditions and under normal RAC chloride levels (Sidebar 3). However, based on reports and analyses, it is clear that the root cause of the failures is SCC. Therefore, it's important to understand from where, how, and how much oxygen is getting into the RACs.

During commissioning and for the first several years of operation, the 2 × 1 facility cited above for having failed the IP sections in both of its RACs, cycled significantly. This mode of operation caused the plant to break vacuum repeatedly, allowing oxygen ingress when the facility was not in service. This explains how oxygen may have entered the system.

With regard to the amount of oxygen present, saturated water typically contains approximately 8 ppm of dissolved oxygen. The actual amount depends on temperature, but for the purposes of this article, 8 ppm is a http://www.hse.gov.uk/research/rrhtm/rr902.htm

Ref 2

good assumption. Fig 4 indicates that, at 8 ppm of oxygen, chloride levels must be well below 1 ppm. With typical bulk-water chloride concentrations of 170 ppb, the concentrations in the crevices easily could be above 1 ppm. Knowing this, it's easy to understand how SCC can be the root cause for the RAC failures.

Failure location on the weld material and the tubesheet is very significant and must be understood. Under ideal conditions, when a tube is rolled into a tubesheet, the seal is sufficiently tight that water cannot migrate between the tube and tubesheet. Therefore, water never should come in contact with the seal weld, which, in turn, would mean no SCC would occur in that region.

However, if a tube is not rolled properly, or if the exchanger sees significant temperature transients causing the tube to contract and expand, a crevice can be created allowing water to migrate between the tube and the tubesheet and contact the seal weld. When this occurs, the water heats up rapidly and boils because of the elevated air-side temperature.

Dissolved solids that were once contained in the bulk water are left behind as steam escapes back through the crevice. This process continues, and the concentrations of impurities, specifically chloride, increase rapidly in the crevice, raising them from ppb levels in the bulk water to probable ppm levels in the crevice.

Based on photos compiled during metallographic analyses, there were definite gaps between the tubes and tubesheets. How the gaps were created remains unclear. Tubes may have contracted and pulled out of the tubesheet when there was a sudden influx of cooler water—at startup or during load transients, for example. Because the tubesheet has more bulk than the thin-walled tubes, the tubes will thermally contract at a faster rate.

Upon a return to normal operation, the tubes may not reseat in the same manner, and gaps/crevices may be produced. If gaps exist between the tube and tubesheet bores, the stress on the weld increases because the tube is

2. Ammonia V/L and its impact on RAC pH control

Ammonia's V/L ratio, the amount of ammonia present in the vapor phase versus that in the liquid phase, varies inversely with pressure—that is, as pressure drops, V/L ratio increases and vice versa. Example: At a steam pressure of 150 psig, V/L is 7; for 2100 psig, it is about 2.5.

This behavior is particularly important regarding pH control in the RAC. Recall from text Fig 1 that HP drum blowdown at approximately 2100 psig and IP drum blowdown at about 470 psig both flow to the IP RAC. As these blowdown streams enter the IP section of the RAC, they flash because of the sudden pressure drop. When flashing occurs, a large portion of the ammonia leaves with the steam because of the change in V/L ratio.

The reduction in bulk-water ammonia concentration depresses the pH. Industry data show IP RAC water can be one pH unit lower than the HP drum water —8.8 versus 9.8, respectively. Considering pH is a logarithmic measurement, this can be significant with respect to corrosion potential. The addition of phosphate, a dissolved alkaline solid that remains in the RAC bulk water, can help increase the pH in any crevices and reduce the potential for stress corrosion cracking.

3. Chloride levels in HRSGs and RACs

Industry chemistry guidelines generally call for less than 3 ppb chloride in demineralized makeup water and condensate; combined cycles typically report 1-3 ppb during normal operation. For the example that follows, 2 ppb is assumed.

Tracing the HRSG/RAC water flow path in text Fig 1, condensate containing 2 ppb enters the IP/HP boiler-feed pump, which takes suction from the condensate-pump discharge header. In the HP drum, chloride concentrates approximately 50-fold to 100 ppb. This means blowdown with 100 ppb chloride is fed to the IP RAC, where it concentrates another three or four times to a nominal final IP RAC chloride level of 400 ppb.

This simple illustration does not consider that IP-drum blowdown dilutes the concentration of chloride in the IP RAC. Analyses indicate that 200 ppb chloride in the IP RAC is not uncommon, which in itself contributes approximately 2.4 μmho to cation conductivity. Important: This is the bulk-water chloride concentration and does not reflect the concentration mechanism that occurs in crevices during heat transfer. The takeaway here is that it may be very difficult to reduce the bulk-water chloride concentration to a level that assures an acceptable chloride concentration in tube-to-tubesheet crevices.

not restrained within the bore. While SCC is the root cause of the failures based on metallurgical analyses, it is possible that fatigue helped to accelerate the failures.

Studies and metallographic analyses confirm that SCC is causing the failures in the RACs. However, it is possible that the role of oxygen and the mechanical aspects of the RAC construction have been underestimated when it comes to the true root cause of the SCC. It is clear that any crevices created, whether from the manufacturing process or the tubes contracting and expanding during plant load transients, can allow ppb level chloride in the bulk water to concentrate to the ppm level in the crevice. Couple this with added applied stresses—such as temperature and vibration—and the susceptibility of the RAC to failure increases.

Preventing SCC is neither simple nor straightforward. It has been suggested that reducing chloride levels in the cycle chemistry, together with the addition of trisodium phosphate, will help reduce the potential for SCC. While it stands to reason that this is a prudent course of action, the plant's operating profile and other factors likely would make the desired goals very difficult to achieve. Mitigating SCC may require more than chemistry changes alone.

The path forward

The most effective means for minimizing SCC potential are reducing applied and/or residual stresses and controlling the local environment—that is, preventing to the degree possible, stagnant areas and crevices where contaminants may concentrate. Formulating a path forward to reduce the SCC potential, and thus RAC failures, should have three focal points: chemical, operational, and mechanical. All of these are intertwined.

Some 501G plants have made chemistry adjustments—such as feeding trisodium phosphate directly to the RACs and minimizing chloride levels in the cycle water—based on the OEM's initial attempt to provide some direction (Table 1). However, high concentrations of the alkaline agent would be needed to neutralize the acidic environment present.

And if the caustic injected were to concentrate to excessive levels, say greater than 10,000 ppm, caustic cracking of stainless steel could occur, based on DOE information. While unlikely that such excessive concen-

Table 1: OEM recommendations to mitigate stress corrosion cracking, and related concerns

Parameter	Target	Normal	Thoughts and concerns
Phosphate, ppm	0.6	0.25 - 1.0	Based on the research provided, it is understood that elevating the pH, along with the addition of phosphate, could provide some buffering capacity for minimizing SCC potential. The recommended phosphate source has been trisodium phosphate (TSP), which, in addition to its contribution of phosphate, also helps buffer the pH to targeted levels. Note that TSP will not become corrosive even if evaporated to dryness in crevices. Fig 5 is an example of a Phosphate Continuum Control Chart for powerplants using phosphate internal drum treatment. As the graphic shows, there is a direct relationship between the amount of TSP present and the theoretical pH achieved at that dosage. Looking at the recommendations, it appears that either the phosphate upper limit should be increased, or the pH target and upper limits lowered. Be aware that the concentration of ammonia in the steam/water cycle can have a significant impact on cycle pH (Sidebar 2).
pH	9.6	9.2 - 10.0	
Sulfate	N/A	N/A	The author is unaware of any chloride or sulfate limits recommended by the OEM. It is difficult to determine what bulk-water chloride levels would deposit enough chlorides in the crevices to concentrate sufficiently and exacerbate SCC. Also, modeling chloride cycling throughout the HRSG would be difficult (Sidebar 3).
Chloride	N/A	N/A	
Specific conductivity, μS/cm	2 - 4	2 - 6	
Cation conductivity, μS/cm	<1.5	<5	Target would be difficult to achieve given the contributions of all the anions present. Table 3 presents results from actual RAC water analyses which show 1100 ppb (1.1 ppm) of phosphate contributes approximately 4.86 μS/cm of cation conductivity. Furthermore, if the contribution of sulfates and chlorides is considered—0.9 and 1.2 μmhos per 100 ppb each, respectively—the recommendations made above should be adjusted.

tration would occur, with hundreds of crevices present, the possibility at least should be considered.

Additionally, determining the RAC phosphate concentrations required for protection is complicated by the difficulty in monitoring SCC potential throughout the system. Reducing chloride concentrations to achieve positive benefit, considering the flow path and cycle chemistry discussed previously, probably is not practical.

Operational changes made to minimize oxygen ingress when the plant is not in service are relatively easy to implement and a sound strategy. Ref 1 says it is not

http://www.amazon.com/DOE-Fundamentals-Handbook-Chemistry-Volumes/dp/1603220070

Ref 4

Table 2: Pros and cons of changing water chemistry, upgrading materials to reduce RAC failures		
Options	**Advantages**	**Disadvantages**
Add trisodium phosphate	Addition of trisodium phosphate will increase the pH of RAC bulk water. Research suggests that a pH >7.0 can significantly reduce the potential for SCC. Phosphates can be effective in minimizing SCC if present in certain concentrations. It is believed that phosphate prevents acidification at local corrosion sites, stimulates passivation, and possibly moves the electrochemical potential outside the limits for SCC (Ref 3). Plant operates as an AVT(O), with ammonia being the only chemistry used for pH control. As such, pH control in the RAC is difficult; phosphate could improve RAC pH and possibly minimize SCC (Sidebar 2).	Note that while raising pH can be effective, the alkaline agents added must be able to penetrate into the crevice at a high enough concentration to provide any benefit; this is not assured. As with any crevice-corrosion mechanism, anionic contaminants, such as chloride and sulfate, can be drawn into the crevice via a concentration mechanism. Hydrolysis then takes place and produces an acidic environment. This can greatly depress the local pH, requiring a large amount of alkaline agent.
Minimize chloride level	Limiting the amount of chlorides present also impacts the potential for SCC. If the chloride concentrations in the bulk water can be minimized, the amount of chlorides in the crevice can be minimized.	The amount of chloride needed to initiate and propagate SCC at the elevated temperatures seen in the RAC is in the very-low ppb range (Fig 2). Since the HRSG's IP and HP drums provide makeup to the IP RAC in an uncontrollable proportion, it would be very difficult to maintain chloride levels in the low-ppb range suggested by the graphic.
Duplex 2205 or titanium	This is, perhaps, the most effective method for mitigating RAC failures. The suggested materials would significantly reduce, if not completely eliminate, SCC potential.	Costly. An economic study would determine if better materials were a viable option.

uncommon for failures to occur during startups, shutdowns, and idle periods because environmental conditions during these times—such as highly oxygenated water—propagate SCC. Most plants go to great lengths to lay up boiler systems properly for this very reason, using nitrogen blanketing during wet layups and air blowers and desiccants during dry layups.

Much information is available on the subject and it's is easy to access using the QR codes provided. EPRI's Jim Mathews published an article in spring 2013 on layup practices for various scenarios (Ref 2) and the scientists at UK-based European Technology Development Ltd recently released *Preservation Guidelines for CCGT and Conventional Power Plants during Short- and Long-Term Shutdowns"* (Ref 5). Use the keyword search function at www.ccj-online.com to access still more experience.

http://www.ccj-online.com/develop-a-robust-preservation-program-to-protect-plant-equipment-during-lay-ups/

Ref 5

Because the RAC failures have occurred on the seal weld material and the tubesheet, two action items to consider are the writing of tighter manufacturing specifications to ensure tubes are rolled properly, plus the use of corrosion-resistant alloys as suggested in Table 2.

Taking all aspects of the RAC failures into consideration, it is probable that better materials will be the ultimate resolution, in much the same way alloy steels can prevent flow-accelerated corrosion in HRSG tube bundles. While chemistry and operational changes can be made, their ability to minimize the SCC potential may not be adequate to completely eliminate the failures.

Some plants already have elected to rebuild their RACs with a more corrosion-resistant alloy. Unknown at this point is the cost and return on investment of this change. Because not all 501G plants have experienced failures, it is necessary to compare the cost of constructing RACs with a more corrosion-resistant alloy to the cost of the possible downtime caused by RAC failures. Given the youth of the 501G fleet, conversations surrounding RAC failures will surely continue. CCJ

Table 3: Contributions to drum, RAC conductivities made by various cations

Cations	IP drum	HP drum	IP RAC	LP RAC
PO_4, ppb	N/A	N/A	360	1100
PO_4, μS/cm	N/A	N/A	1.59	4.86
Cl, ppb	Undetectable	19	54	170
Cl, μS/cm	Undetectable	0.228	0.65	2.04
SO_4, ppb	Undetectable	59	180	680
SO_4, μS/cm	Undetectable	0.528	1.61	6.09
Cation conductivity, μS/cm	0.06	0.811	3.85	12.99
Cation conductivity (calculated), μS/cm	0.06	0.81	3.85	12.99

Nalco

Clean fouled HRSG tubes, increase revenue

By Christopher Norton and **Randy Martin,** Environmental Alternatives Inc

Gas-side deposits and corrosion of HRSG heat-transfer surfaces are inevitable and are a common cause of reduced steam production, low steam temperatures, and degraded gas-turbine performance. These effects contribute to reduced electricity production and lost revenue.

Many factors contribute to deposit formation on HRSG tubes—including fuel sulfur content, tube leaks, insulation failures, ammonia injection in excess of that required for NO_x control, and condensation caused by low stack temperature. Corrosion also is problematic at plants operating in locations with high humidity, particularly those facilities designed for base-load service and required to cycle. Additionally, HRSGs equipped with oil supplemental firing experience an increased rate of tube fouling than when burning only natural gas.

Over time, fouling can bridge the gap between adjacent tube fins or other heat-transfer surfaces, further disrupting heat transfer and increasing gas-side pressure drop. Recall that gas-turbine (GT) and combined-cycle efficiency decrease with increasing delta p. In cases where HRSG performance is severely compromised, the entire plant may require an extended forced outage to repair corrosion-induced tube leaks, remove deposits from heat-transfer surfaces, or even replace an entire module.

Mitigate deposits, corrosion

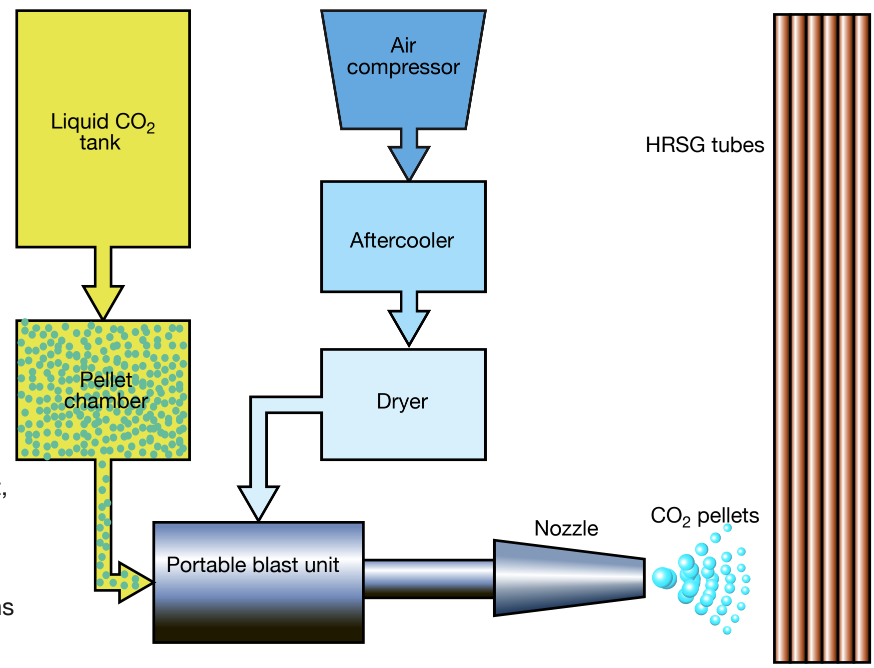
Removing HRSG gas-side deposits should be a part of every plant's annual maintenance program. Effective planning can be improved by closely monitoring specific operating parameters—such as GT backpressure, steam production and temperature (for each pressure level), and stack temperature—and comparing the data against corrected plant design conditions. Plant heat rate and output also should be tracked.

Careful review of the data can provide advance warning about the location and amount of fouling, and the rate of deposit formation within the HRSG. This information allows the owner to determine precisely when an outage for tube cleaning is economically justified. In general, HRSG cleaning is required when the gas-path pressure drop across the HRSG reaches 3 to 4 in. H_2O over the "new and clean" condition.

Once the need for cleaning has been established and an outage date determined, the next step is to select the optimal cleaning technology. The standard options are high-pressure water blasting, grit blasting, acoustic cleaning, and CO_2 blast cleaning. The plant owner should carefully consider the pros and cons associated with each cleaning option before making a final selection.

High-pressure water can be effective but may also have the undesirable side effect of a water/deposit interaction that creates an acidic environment and accelerates tube corrosion. It also could turn the water/deposit mixture into a concrete-like substance when

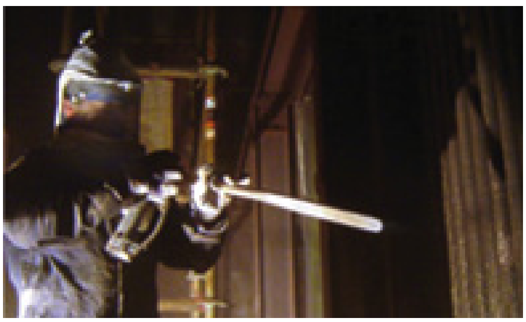
1. CO_2 blast cleaning uses small cylindrical pellets (approximately 1/8 in. across) of dry ice to remove foulants, rust, and scale from tube and fin surfaces



2. Liquid CO_2 is converted to pellets of dry ice at the powerplant where the end product is used for cleaning tubes and fins (right) the plant is restarted. Important to remember is that this cleaning technique is limited to line-of-sight deposits and the high-pressure water may push removed deposits further back into inaccessible regions of the HRSG.

Unless carefully performed, high-pressure water blasting also can quickly damage insulation that is extremely difficult to access for repairs and/or may erode some tubes or damage tube fins. Finally, contaminated water is difficult to contain and may require expensive waste disposal, if determined to be a hazardous waste.

Grit blasting, also limited to line-of-sight cleaning, can quickly thin the tube wall or damage fins if not carefully performed by experienced technicians. Unfortunately for the plant owner, thinning of tube walls is not obvious during cleaning but will become apparent when the rate of tube leaks increases in the future. Like high-pressure water blasting, A large amount of waste material is generated, some of which may be classified as hazardous and require special (read "expensive") handling and disposal.



3. Nozzle directs the pellets directly on deposits. When the CO_2 pellet changes phase from solid to a gas, the deposit breaks free

Owner/operators report mixed results when using sonic horns for deposit removal, particularly in the cold end of the HRSG. Sonic blasting is ineffective for removing ammonia salts and baked-on deposits.

CO_2 blast cleaning

The remaining option for HRSG cleaning is CO_2 pellet blasting, the only option that is non-

4, 5. Typical fouling and bridging of tubes before cleaning is shown at left. At right, the same tubes have been restored to "new and clean" condition by blasting with CO_2 pellets destructive and produces no secondary waste products. This is a dry process and does not contribute to corrosion or erosion of heat-transfer surfaces. Just as important to the owner, deep cleaning between tubes can be performed.

CO_2 blasting penetrates and completely cleans modules located deep within the HRSG, eliminating the time and expense of mechanically spreading tubes to access tubes not in the technician's line-of-sight. It has been proven by over 20 years of industry experience and is recognized by HRSG manufacturers as a cleaning best practice (Fig 1).

The general cleaning process is illustrated in Fig 2. CO_2 pellets are fed into a portable machine that is connected to a high-pressure compressor. The pellets are educted into the air stream and propelled through a hose to a specially designed nozzle that propels them at speeds up to 1000 ft/sec. The pellets exit the nozzle and penetrate the debris layer on the surface being cleaned (Fig 3).

The CO_2 sublimates once the pellets penetrate the deposit. During sublimation at atmospheric conditions, the CO_2 pellets undergo a transformation from a solid directly to a gas, unlike ice that must first melt into liquid water before evaporating into vapor form. When CO_2 sublimates from a solid to a vapor, it expands 750 times in volume creating a "mushroom" effect inside the deposit that lifts and removes deposits from metal surfaces. A HEPA vacuum system collects the debris. Two typical HRSG tube banks shown prior to and following CO_2 blast cleaning in Figs 4 and 5, respectively, illustrate cleaning effectiveness.

Making CO_2 pellets

High-density CO_2 pellet production is the cornerstone of the cleaning process. Sufficient pellets are manufactured onsite to guarantee the quality and density for maximum cleaning effectiveness. Pre-made pellets from an offsite dry-ice vendor usually are 24 to 48 hours old before they are used and will have already experienced a loss in density. Lower-density pellets begin to sublimate in the hose and "soften." Soft pellets are a less-effective cleaning medium because they are less able to reach the bundle interior.

Onsite production of high-density CO_2 pellets is possible by using a completely self-contained mobile support trailer (Fig 6). The trailer houses a 350-psig air compressor, air dryer/aftercooler (for clean instrument grade air with low moisture content), a liquid CO_2 storage tank, a pellet conversion unit, and all necessary support systems for direct connection to onsite power. The trailer also carries all the necessary tools, personal protection equipment, and other safety gear to the plant.

HRSG tube cleaning shows positive impact on plant performance

HRSG performance data	Before cleaning	After cleaning
HP pinch point, F deg	46.0	35.1
HP steam flow, lb/hr	261,100	268,600
IP pinch point, F deg	68.1	35.5
IP steam flow, lb/hr	73,800	74,600
Nominal steam turbine output, kW	81,710	82,830
Restored steam turbine output, kW		1120

Case studies

The true effectiveness of high-density CO_2 pellet blast cleaning becomes evident when comparing pre- and post-cleaning plant performance data—such as pinch points, steam flow, heat rate, fuel consumption, pressure drop, and unit power. In the first case study, the performance restoration experienced after cleaning is presented. In the second, the value of a CO_2 blast cleaning allowed

6. Mobile support trailer houses all the CO_2 blast cleaning equipment, produces the high-density pellets as needed, and carries support tools

the owner to cancel a scheduled major outage and avoid purchasing a replacement economizer module.

Regaining lost performance

Monitoring important performance data points at a nominal 500-MW combined cycle in the Northeast is part of the plant's ongoing HRSG maintenance and cleaning program. The data collected are used to develop performance trends and to estimate the power output that can be restored by cleaning. A simple economic analysis compares the value of lost power sales revenue when running with a fouled HRSG, with the lost revenue incurred for an outage and the cost of an HRSG cleaning. This analysis helps the plant owner decide when a cleaning should be scheduled.

Data collected from the plant historian before and after an HRSG cleaning is shown in the table. The capacity restored as a direct result of the cleaning was 1120 kW. This plant normally operates at a 90% capacity factor and sells power into the market at 3.5¢/kWh off-peak, a conservative price. Assuming the plant can sell the additional power generated, the gross savings resulting from the restored power is about $309,000 annually. The owner's payback for the HRSG cleaning is a matter of weeks.

Another approach to determining the value of an HRSG cleaning is to calculate the fuel saving that occurs when a plant runs at a fixed power output. In that situation, the fuel savings is a function of the plant's improved heat rate. If the HRSG gas-side pressure drop increases by 4 in. H_2O because of fouling, the resulting heat-rate increase can be determined from plant-specific design data.

For this case, the heat-rate improvement is approximated as proportional to the power restored (1120 ÷ 500,000) or 0.22%. Assuming a typical 500-MW combined cycle has a gross heat rate of about 7000 Btu/kWh, the heat-rate restoration is about 16 Btu/kWh. If fuel is purchased at $3.50/million Btu then the annual fuel savings for the improved heat rate is about $220,000.

Avoiding an unexpected cost

The second case study involves a combined-cycle cogeneration plant in the UK that produces steam and electricity for two paperboard mills. The plant is equipped with a GE LM6000 gas turbine and a Siemens steamer.

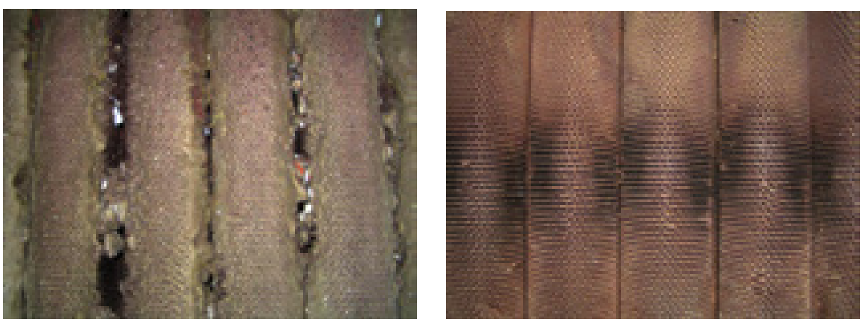
Sticky combustion products were condensing out on the HRSG economizer tubes as a tar-like substance because the flue-gas temperature had dipped below the dew point. In addition, ceramic fiber insulation blocks used in the HRSG combustion zone were deteriorating with fiber strands coming lose into the gas flow and sticking on the economizer's finned tubes. The combined effect was a loss of heat transfer in the economizer and a rise in the HRSG gas-side pressure drop that significantly reduced steam production.

Initially the plant owner thought to replace the entire economizer module with one having a recirculation system to take a portion of the hotter economizer outlet water and return it to the inlet to ensure tube-metal temperature remains above the dew point. However, procuring an expensive new economizer module was going to require at least 40 days, thereby putting the plant owner at commercial risk for failing to supply the contracted amount of steam.

Alternative approach: The plant owner investigated cryogenic cleaning of the economizer even though there was no large boiler experience with the technology in the UK at the time. However, dry ice was used to clean small equipment—such as motors and generator windings. The plant owner sent representatives to the US to observe the cleaning process in action and the decision was made to bring the process to the UK for the first time.

The CO_2 pellet blasting equipment was shipped to the UK for a planned HRSG outage. Figs 7 and 8 show the state of economizer tube fouling before and after cleaning; Fig 9 shows the debris removed from the HRSG after the cleaning was completed.

The cleaning process was very successful and at the close of the outage the plant resumed supply of the contracted amounts of steam to the customer. By selecting CO_2 pellet cleaning, the owner avoided an unnecessary economizer replacement, sidestepped an extended outage for the economizer replacement, and avoided an unpleasant contract discussion. CCJ



7, 8. Economizer fouling reduced process steam flow and increased the pressure drop across the HRSG to unacceptable levels (left). A new economizer was believed the only viable solution. Fouling was eliminated (right) during a short maintenance outage and the plant resumed full process steam supply to its customer

9. The sticky material on economizer gas-side surfaces was reduced to an easily handled waste product acceptable for environmentally safe disposal

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First-rate aero-engine training at virtually no cost

The best deal in the aero sector of the electric power generation business likely is a "ticket" to the Western Turbine Users Inc's 24th annual conference and exhibition, March 23 – 26, at the Palm Springs Convention Center.

The employee with limited aero experience that you hired to replace a recent retiree will return to the plant with a good sense of what the engine is all about and the problems most likely to occur—a solid educational foundation to build upon. The more experienced people on your staff should attend to continue learning, an incremental process. You grow professionally with every meeting and become more valuable to the organization.

Hundreds of LM2500, LM5000, LM6000, and LMS100 owner/operators participate in WTUI meetings for the updates they receive on fleet issues from the OEM and its licensed repair depots—TransCanada Turbines (TCT), Air New Zealand Gas Turbines (ANZGT), Avio SpA, IHI Corp, and MTU Maintenance Berlin-Brandenburg GmbH. The depots are independent organizations authorized by GE to perform repairs up to Level 4.

The comprehensive technical presentations and open discussion periods conducted during the breakout sessions for each engine contribute to maintaining top performance; they offer sound guidance on how to identify potential issues early and what proactive steps can be taken to prevent unplanned outages.

The closed-door sessions for users run more than nine hours over the two-and-a-half-day meeting. Programs specific to each engine, carefully planned by the depots and the WTUI leadership (Sidebar 1), are detailed in nominal 100-page full-color notebooks given to attendees at their breakout session of choice. At typical depot notebook contains the following material:

- Engine fleet statistics, manuals, and definitions.
- A review of recent service bulletins (SB) and service letters (SL) issued ty the OEM.
- A summary of depot findings since the last meeting, information that's invaluable for anyone planning an outage.
- Causes of performance loss and how to correct them.
- Lifetime management of critical parts.
- Engine preservation, handling, and transportation.
- Expectations with regard to maintenance intervals.

Session notebook in hand, it's easy to follow the depot presentations and jot down additional notes where necessary. And if you step out of the room to take an important call, WTUI has you covered. CEO Sal DellaVilla and his colleagues at Strategic Power Systems Inc, Charlotte, attend every session to take notes, which are then posted in the user-only portion of www.wtui.com. SPS's notes also form the basis for the summaries of the 2013 breakout sessions below.

Beyond the focused technical sessions, the world's largest conference on aero engines features the largest exhibition of gas-turbine products and services anywhere. You're sure to meet at least a few suppliers who can offer suggestions on how to improve plant performance. The exhibit hall will be open during the reception Sunday evening (March 23) and all day Monday and Tuesday (Sidebar 2).

Important for newcomers to note is that WTUI conducts orientation sessions at 3:30 Sunday afternoon, following the optional golf and tennis tournaments. The LM engine familiarization workshop, which runs for about an hour and a half always gets high marks from first-timers. Typically one-third of the users are attending their first Western Turbine meeting, many unfamiliar with one or more engines supported by the group.

The crash course will be taught again this year by Bob Boozer of Reed Services Inc. It is excellent preparation for the breakout sessions beginning Monday morning. Acronyms used in casual conversation by this group are defined in Sidebar 3. Boozer's workshop will be followed by an SPS presentation explaining the Operational Reliability Analysis Program (ORAP®), an automated system for monitoring and reporting RAM-D (reliability, availability, maintainability, durability) data for gas and steam turbines worldwide.

SPS is an unbiased third party that provides turbine users the means to benchmark their assets against the fleet regarding inspection intervals, time-to-repair statistics, component failure rates, best practices, etc. Unit-specific information also is provided to owners of those assets. SPS works closely with WTUI to support LM users.

1. WTUI leadership

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Engine breakout sessions

LM2500

Session chair and discussion leader for the 2013 LM2500 breakout sessions was John Baker, who manages the 1 × 1 Clearwater Cogeneration Plant for Riverside Public Utilities and is a member of the WTUI Board of Directors. This was Baker's fifth year as the LM2500 track chair. He was supported by the following depot representatives: Antonio Errico of Avio, Ralph Reichert of MTU, Brad Downie of TCT, and Sabro Muratbegovic of ANZGT. Cindy Alicea and Karl Maier of SPS were the session secretaries (note-takers).

Case history #1. One of the opening discussions focused on the heavy damage to compressor blades and vanes on a unit with 50,000 service hours. Three 10th stage blades were released and went downstream. Inspection revealed cracks in the dovetails of many blades. Minimal background information was available for the failure analysis because there were no maintenance or inspection records for the engine.

Attendees were reminded that you can't ignore the compressor during inspections and that accurate recordkeeping is important. A depot representative said he was aware of similar failures on other engines in the fleet over the years, but none associated with the 10th stage. This machine was said to have thrown a blade previously, but it was never found.

Case history #2. The top half of a first-stage HP compressor blade released into the air path and caused extensive damage. Machine had only 33,000 operating hours and was overhauled 400 hours before the event. Investigation revealed a small pit on the pressure side of the blade and a small crack on the suction side: The two met in the middle of the airfoil. Damage totaled about $1 million and likely would have been more if the engine were at full speed when the blade separated.

Pits found in other blades were so small they were not visible to the naked eye. Exact cause was unknown but personnel believed they might be related to FOD/DOD (refer to Sidebar 3). Engine was equipped with a sock and FOD screen on the front end; blades were overhauled, not new. At least one tiny piece (⅛ in.) of the stainless steel screen had liberated because of corrosion and gone downstream. Suggestion to attendees: When checking FOD screens, do a careful close-up inspection for tiny discontinuities in the material—they're important.

A user commented that the FOD screen on one unit at his plant was removed because of compressor airfoil dings caused by bits of wire rope going downstream. He claimed less maintenance for the last 12 years because of this modification.

Case history #3. Engine had operated 32,000 hours since its last overhaul and HPCR vibration had been increasing over time. Operations personnel were baffled by a vibration signature that changed with every start. The unit was shut down when vibration exceeded recommended limits. The owner could not point to an obvious cause of the vibration until that time. An inspection team found the air-duct Vespel® strip completely disintegrated and the majority of blade gaps out of limits.

A depot visit revealed several separate problems that could have caused the vibration, including ones associated with the CFF, HPCS, CRF, HPTR, and TMF. Defects in those areas were repaired. The depot said the entire engine exceeded vibration limits upon receipt, making it difficult to determine the root cause of the problem.

The owner believed the cause

2. Conference at a glance

Information current as of January 1; verify at www.wtui.com

Sunday, March 23

Morning

8 to1 pm — Golf tournament, Escena Golf Club
11 to 2 pm — Tennis tournament, Plaza Racquet Club

Afternoon

2 to 7:30 — Conference registration
3:30 to 5:30 — New-user orientation/SPS introduction
5:30 to 8:30 — Welcome hospitality reception

Monday, March 24

Morning

7 to 8 — Breakfast
7 to 4 pm — Conference registration
8 to 5 pm — Exhibit hall open
8 to 9 — General session
9 to 10:15 — Depot presentations
9:30 to 3 pm — Spouse tour, Palm Springs Indian Canyons jeep excursion
10:15 to 10:30 — GE Services presentation
10:30 to 10:45 — Break
10:45 to noon — Breakout sessions for LM2500, LM5000, LM6000, LMS100

Afternoon

Noon to 2:30 — Lunch/exhibits
2:30 to 5:30 — Breakout sessions for LM2500, LM5000, LM6000, LMS100
6:30 to 8:30 — Monday night reception at Palm Springs Air Museum

Tuesday, March 25

Morning

7 to 8 — Breakfast
7 to 4 pm — Conference registration
8 to 4:30 pm — Exhibit hall open
8 to 8:50 — "Worldwide GT Business Update," Mark Axford, *Axford Consulting*
9 to 10 — Breakout sessions for LM2500, LM5000, LM6000, LMS100
10 to 10:30 — Break
10:30 to noon — Breakout sessions for LM2500, LM5000, LM6000, LMS100

Afternoon

Noon to 3:30 — Lunch/exhibits
3:30 to 4:30 — "Fuel and Water Valve Maintenance," Eric Freitag, *Woodward Inc*
"GHG Market Update," Jackie Frelita, *Elements Markets LLC*
"HRSGs in Flexible Operation," Ned Congdon, *HRST Inc*
4:30 to 5:30 — "Analyzing Complex Vibration Issues," Maki Onari and Bill Marscher, *Mechanical Solutions Inc*
"CO, NO_x Emissions from LM Turbines," Ted Heron, *Environex Inc*
"Control Loop Tuning," Gary Drew, *Metso Corp*

Wednesday, March 26

Morning

7 to 8 — Breakfast
8 to 10:30 — Breakout sessions for LM2500, LM5000, LM6000, LMS100
10:30 to 10:45 — Break
10:45 to 11:45 — GE new products update
11:45 to noon — Wrap-up and adjourn

Afternoon

1:30 to 3:30 — CPV Sentinel Energy Project tour. The 8 × 0 LMS100-powered peaking facility began supplying power to the grid May 16, 2013.

might possibly have been package misalignment but the depot thought otherwise. Field service had inspected the unit before it was shipped to the shop, noting that trim balance is not the solution for everything. The technicians said that sometimes the machine must be stripped down and realigned.

Case history #4. Interesting is the wide range of issues you learn about during the user and depot presentations and open discussion sessions at Western Turbine meetings. Consider the engine that experienced high vibration upon restart after two years of idle time. Among the unknowns were operating hours since COD or last overhaul. A large amount of debris was found in the engine because of its inactive status.

The HPCR air duct was loose and the Vespel strip completely missing. The owner wanted a least-cost return to service; efficiency was not a concern for this rarely used engine. The air duct was removed and Vespel strip replaced. General cleanup was done and the unit returned to operational status. HPC vibration was measured and satisfactory.

Case history #5. Engine was sent to a depot because of high vibration. It had been 32,000 hours since the previous overhaul. Shop personnel found the rear shaft scraped and unrepairable. The shaft was replaced.

Case history #6. The depots reported chipping of the rub coat on three LM2500+ engines in 2012—all operating base-load. Thinking was that perhaps the higher operating temperatures associated with this machine were the underlying cause. Regular borescope inspection was recommended. Rub coat was replaced in the three affected engines.

Case history #7. During removal of an LM2500+ engine, personnel discovered that an air/oil seal had liberated and damaged some stationary parts. Seal loss was attributed to high-cycle fatigue. The seal was replaced with one of newer design. Interestingly, the seal loss did not impact oil consumption; there was no leak to indicate a problem.

Case history #8. Cracks propagating from unused bolt holes, or from holes with loose bolts, have been found in the CRF mid-flange. Cracks may grow inwards toward the case, or go outwards. High-cycle fatigue experienced by startups and shutdowns was said to be one of the main causes. Bolt tightness should be verified periodically and the flange inspected for cracks.

Weld repairs can be made by depots if cracks radiate away from the frame; otherwise the mid-flange must be replaced. The latter is a very complex repair because of the amount of welding and heat treatment involved.

Case history #9. The combustible-gas detector alarm sounded on an LM2500 and the unit, running normally on an oil platform, shut down. Operating hours since COD totaled 122,000, 38,000 since the last overhaul. A 4-in. casing crack in the CRF was found during an inspection to determine the reason for the alarm. Such a crack was considered "out of character" by session participants. The exhaust diffuser was damaged as well.

There was no evidence of temperature rise or unusual vibration. Operations personnel had seen an increase in vibrations, but nothing excessive or over the limits. Experts believed the root cause was high-cycle fatigue and that the crack was probably propagating over time. Increased vigilance during inspections was recommended, but such cracks are difficult to see given all the piping on the engine. The NO_x steam ring was removed and mounted off the engine with flexible steel-braided hose for steam delivery. No problems have been reported since.

Case history #10. A user reported several CRF fuel-nozzle pad cracks on a gas-fired unit equipped with

3. Acronyms to remember

AGB—Accessory gearbox (also called the transfer gearbox)
AVR—Automatic voltage regulator
CCM—Condition maintenance manual
CCR—Customized customer repair
CFF—Compressor front frame
COD—Commercial operating date
CPLM—Critical-parts life management
CRF—Compressor rear frame
CWC—Customer web center (GE)
DEL—Deleted part
DLE—Dry, low emissions combustor
DOD—Domestic object damage
EM—Engine manual
FFA—Front frame assembly
FOD—Foreign object damage
FPI—Fluorescent penetrant inspection
FSNL—Full speed, no load
GG—Gas generator (consists of the compressor and hot sections only)
GT—Gas turbine (consists of the gas generator pieces with the power turbine attached)
HCF—High-cycle fatigue
HGP—Hot gas path
HPC—High-pressure compressor
HPCR—High-pressure compressor rotor
HPCS—High-pressure compressor stator
HPT—High-pressure turbine
HPTN—High-pressure turbine nozzle
HPTR—High-pressure turbine rotor
IGB—Inlet gearbox
IGV—Inlet guide vane
IPT—Intermediate-pressure turbine (LMS100)
IRM—Industrial repair manual
LM—Land and marine
LCF—Low-cycle fatigue
LO—Lube oil
LPC—Low-pressure compressor (not on LM2500; just LM5000 and LM6000)
LPCR—Low-pressure compressor rotor
LPT—Low-pressure turbine
LPTR—Low-pressure turbine rotor
LPTS—Low-pressure turbine stator
NGV—Nozzle guide vane
OEM—Original equipment manufacturer
PN—Part number
PT—Power turbine (turns a generator, pump, compressor, propeller, etc)
PtAl—Platinum aluminide
RCA—Root cause analysis
RFQ—Request for quote
RPL—Replaced part
SAC—Single annular combustor
SB—Service bulletin
SL—Service letter
SUP—Superseded part
STIG—Steam-injected gas turbine
TA—Technical advisor
TAT—Turnaround time
TAN—Total acid number (lube oil)
TBC—Thermal barrier coating
TGB—Transfer gearbox (also called the accessory gearbox)
TMF—Turbine mid frame and thermal mechanical fatigue
VBV—Variable bleed valve (not on LM2500; just LM5000 and LM6000)
VIGV—Variable inlet guide vanes
VSV—Variable stator vane

steam injection. Crack repairs and replacement of rigid steam piping with appropriate steel-braided hose solved the problem.

Case history #11. One second-stage HPC turbine blade in each of nine compressor drivers (eight LM2500 DLE engines and one G4) owned by a pipeline operator suffered cracking in the dovetail section. This may sound statistically impossible, but it's true. Owner thinks the cracking, which is under investigation, might be related to the wide range of ambient temperatures (-40F to 80F) experienced at each site. Some units are running with cracks but their propagation is closely monitored by regular inspection. The owner has installed HEPA filters and eliminated water washes.

Case history #12. Wear and tear of water injection nozzles for NO_x control was raised as a concern. One user said he sent nozzles out for inspection and all failed; a second opinion from an alternative contractor said they all passed. Whom do you believe? It was said that the delivery time for replacement nozzles ordered through the OEM can take nine months.

Case history #13. An owner with LM2500+ DLE engines said a bolt from the inlet shroud on one machine got loose and wrecked the compressor. Some heat shields also were reported as "missing" and the melted remains found fused to first-stage nozzles in the HP turbine.

Case history #14. DLE combustor dome fretting was experienced on one unit and considered unrepairable. Root-cause investigation was ongoing at the time of the meeting. Investigators thought acoustic vibration might be the gremlin. They said fretting was associated with the older types of DLE combustors. One user in the group said in many cases a bad pre-mixer is the cause, but that the condition was not "normal." Depot action is to repair or replace as necessary.

Case history #15. DLE heat shields experienced excessive TBC loss, exposing the base material. Condition is conducive to HPT damage and can cause a high temperature spread. Regularly inspect the combustor and replace if cracking of heat shields is identified. Depot suggestion was to keep acoustics low.

Case history #16. HPT first-stage nozzle platform oxidation was experienced on a unit equipped with water injection for NO_x reduction. No coating was completely successful in preventing the oxidation, attributed to the higher heat rate consistent with water injection. Regular borescope inspection was suggested, with replacement of blades when necessary.

Case history #17. Breaking of the outer seals on HPT first-stage nozzles was attributed to high-cycle fatigue. This caused an increase in emissions during operation; damage was detected because of the associated temperature spread. Borescope inspection also can identify bad seals. The depot action is to rework or replace the nozzle.

Case history #18. Chip detector alarm in the lube-oil system warned of a TMF bearing failure. Depot found the bearing broken upon arrival at the shop. Debris was found in the pump strainer. Bearing was relatively new; engine had only 4000 operating hours. Contamination was suspected as the root cause based on finding machine chips in the C-sump.

Case history #19. Second-stage blades contacted the TMF multi-piece liner at some point between the 25,000- and 50,000-hr inspections. Original-style leaf seals liberated but this was not considered an issue. Users were reminded that the two-piece liner is meant to expand and contract different rates and this can cause binding. The action urged was to replace the two-piece liner with the one-piece liner/improved leaf springs as recommended by SB-229.

Case history #20. TMF liner rivets can potentially damage the HPT. During engine operation, thermal expansion/contraction cycles may cause rivet heads to liberate. Recommendation is to replace rivets with bolts (see SB-238). If you find five rivets in total, or two in one row, are missing, it's important to switch to bolts as soon as possible. Replacement can be done in the field in a timely and cost-effective manner.

Case history #21. TMF cast cases have cracked on some units and the depots have replaced them with fabricated cases. This is recommended for engines still equipped with the original cast case. The job, which is expensive, can be done in the field, but it's easier to do in a depot shop.

Case history #22. Water used for NO_x reduction must be of high quality. Hot-section parts on one unit were damaged extensively by chemical attack. Spray nozzles had completely disintegrated. Engine operated for more than two years with poor-quality water; pH was out of limits.

The OEM's Xtend™ hot-section kit for the LM2500 generated several minutes of discussion. Recall that Xtend contains advanced components developed for the LM2500+G4 and is said to double the lives of combustor and hot-section parts to 50,000 hours when dry gas fuel is burned. A depot representative said that there were 79 units operating with the Xtend upgrade, and some were beyond 50,000 service hours. Here are a couple of takeaways from the discussion:

- A user noted that first-stage nozzle burn was evident at 4500 hours and he did not expect to reach 50,000 hours.
- Nozzles and other components can be overhauled at 50,000 hours, but blades must be scrapped. The high operating temperatures are said to make the blade material brittle.
- An owner/operator asked, "If a LM2500 base engine were operating at its design temperature (lower than the +G4) with Xtend, could it go beyond 50,000 hours between overhauls?" Answer: No, for first-stage blades. Second-stage blades are on a case-by-case basis; some have achieved 75,000-hr intervals.
- Another participant asked if a base engine with an Xtend package could be operated in an under-fire condition. An OEM representative said the company was investigating if under-fire operation were appropriate. Reportedly, cracks found on one or more engines were believed a result of under-firing. Other users said they were running at half load without any issues.

Closely related to this discussion thread was mention of erosion on first-stage HPTR Xtend blades and nozzles on two engines—one with 4000 service hours, the other 7000. Units are close to the sea, burn oil, and use water for NO_x control. Owner was told to continue operating and inspect regularly.

Critical-parts life management was another discussion subject. Users were made aware that tracking of parts life is their responsibility and that the information received from the tracking effort is essential for depot repairs. As noted earlier, Strategic Power Systems offers that service to LM owner/operators through its Cycles Tracking™ solution.

LM5000

Session chair and discussion leader for the LM5000 breakout sessions was Andrew Gundershaug, plant manager of Calpine Corp's Solano Peakers; session secretary, Tom Christiansen, senior VP, Strategic Power Systems Inc. By show of hands, the majority of users present were from US plants; there was one attendee from Canada and one from South America.

The first of the five LM5000 technical sessions was conducted by Chris Martin of ANZGT and Thomas Benisch of MTU. It focused on issues that these independent depots have encountered on LM5000s recently. There are now 102 engines in the fleet, half STIG and half non-STIG. However, only 56 LM5000s are operating today; half of the remainder are listed as customer spares or GE lease engines.

LPC rotor was the subject of several depot findings, including the following:

- Disc corrosion and resulting seized/locked blades are conducive to vibration issues. Users were urged to review SL5000-09-002. Most engines experiencing corrosion are located on a platform, have fogging systems, or operate in a humid environment. Mitigation recommendations: Use correct water-wash procedures, remove zero-stage blades and clean/lubricate disk slots and blade roots. A similar, but more robust and lasting blade-care procedure is possible at a depot.

- Dealing with high run-outs and incorrect mating fits begins with an accurate vibration monitoring system to check shift and polarity of vibration. If vibration is stable, consistent, and repeatable, the site should consider field-balancing the engine—adding balancing weights under the cone.
- Imbalance is affected significantly by first-stage blade gaps, also by the zero-stage blade's tang length (viewed back to front). The gap between the spinner and the blades is critical. If the spinner pushes on the blades, they may lock-up and wear prematurely.
- A coupling-nut incident caught many users by surprise. The nut on one engine split and let the LP shaft drop, causing significant internal damage to the unit. The root cause had not been determined at the time of the meeting, but professional opinion was leaning toward hydrogen embrittlement. Interestingly, the LM6000 fleet had experienced several coupling-nut events and migrated to a new design. For now, the experts recommend replacing the LM5000 coupling nut in-kind after each operating cycle.

LPC stator. Excessive fretting wear attributed to high vibration has been observed at the intersection of the third-stage case aft lip and fourth-stage case vane slot. No repair currently is noted in the IRM, but one is now available via CCR at GE authorized vendors. It reportedly will be added to the IRM in the future.

Front frame issues include these:

- Some No. 1 and No. 3 stationary air/oil seals are known to suffer Teflon seal delamination and resultant oil leakage. There is a service bulletin with a fix for the No. 1 seal, which users generally agree meets expectations. No SB yet for No. 3 seal. However, a similar issue on the LM6000 has been addressed effectively by replacing the Teflon seal strip with a metal/thermal spray repair. Depots recommend the Teflon alternative in the LM5000, at least for now.
- Cracking in front-frame weldment areas attributed to "web" remnants from the casting process has been an ongoing battle.

Come up to speed on the latest O&M and design practices for LM engines in simple-cycle, cogen, and combined-cycle service to:

IMPROVE reliability, availability, heat rate

REDUCE emissions

MAXIMIZE revenue by providing grid ancillary services

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◆ **Comprehensive engine-specific technical training** focusing on current equipment issues. Deliverables include a fully illustrated Training Manual developed by WTUI and repair-depot personnel, and a review of current OEM service bulletins and letters. Technical guidance is provided by Air New Zealand Gas Turbines, Avio, GE, IHI, MTU Maintenance, and TransCanada Turbines.

◆ **User-only open discussion** to share experiences and obtain answers to *your* questions.

◆ **An exhibition** that brings together nearly 200 providers of products and services for LM aero engine operating plants. Learn about new offerings, get product updates, evaluate in-service experience.

◆ **Benchmark your units** against the fleet with ORAP™ data from Strategic Power Systems Inc.

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World's largest user organization serving LM gas-turbine owner/operators

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Renaissance Palm Springs Hotel
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Online registration opens November 1
www.wtui.com, 513-604-8018

There were several incidents in 2009-2010 and an effort was placed on "web" modification/rework that slowed the rate of cracking observed. No incidents observed by the depots in 2011, but three occurred in 2012. Cracks propagation is stopped by using a stop-drill procedure. Users are advised to discuss any cracks identified with the OEM or depot of choice and to inspect the cracks for growth once or twice annually.

- Fretting wear attributed to incorrect seating of the front frame with the air collector has been observed. Recommendations on torqueing and lubrication of bolts, plus other items, are presented in SB-212; increase in bolt size to accommodate higher torque values is discussed in SB-217. A user participant suggested an annual torque check. This involves breaking the lock wire on every bolt, re-torqueing, and installing new lock wire.
- Edge of the sheet-metal skirt sometimes is not machined to the proper limits along the full 360-deg interface, causing incorrect contact and wear. This issue has always existed, but only recently has correction been considered. This requires a one-time machining of the front frame.

HPC rotor issues observed by the depots include these:

- A fourth-stage blade event caused downstream damage. An investigation was ongoing at the time of the 2013 meeting. HPC stator hardware was found severely worn and dirty. Presenter stressed that the VSV hardware must be inspected and cleaned regularly.

  A user suggested the following: Each VSV connection should be checked manually; if it wiggles, it is worn. The alternative to this relatively labor intensive task, he continued, is that the blades get off-schedule and the cost to correct that is higher than to keep the area clean in the first place.
- A 12th-stage blade went missing, causing both upstream and downstream damage; blade locking lugs were intact. However, the root cause will remain a mystery because the investigation at the depot was discontinued.
- High oil consumption, high vibration, and Teflon particles in filters add up to degraded O-ring seals that created a leakage path past the adapter retainer. A user suggested replacing seals every time you pull your booster onsite.
- Erosion was reported on the suction side of the mid-span damper, which is classified as a critical area in the IRM. The only known event of this type was found on a platform unit and is believed related to saltwater. Blades were blended to repair the pitted areas.

HPC stator issues focused on VSV hardware damage—including worn lever arm pins, worn pin holes, missing bushings, distorted lever arms, worn links, worn bearing holes and slots on the actuator brackets, and worn trunnion and bearings on the actuation beam. Such wear and tear often is the cause of a severe stall or full-load trip event because of the off-schedule condition. Users were urged to consult O&M manual GEK 72550, Chapter 5-3.11, and to replace all defective components.

Users offered the following advice:

- Perform a manual check of VSV hardware each time your unit comes off an operating run.
- Spray the outside of the VSV with an oil-cutting detergent, wash, and then steam clean. If necessary, use brushes to get the "tough stuff" off.
- Take a day every 18 months to disassemble and check and clean everything in this area. Unless you do this, the user said, you can't be sure there's no damage.

CRF wear and tear included the following:

- Cracking has been observed in the mid-flange bolt-hole tabs. Depot visits also have identified bolt-hole elongation to mid-flange, brackets, and stiffeners. Loose bolts in this section of the unit are relatively common. Experts recommended regular inspections for cracking and loose bolts. Interestingly, the depots have not found any flange cracks in the last three years on the LM5000 as they have on the LM2500 (see above).

- Broken bolts have been found on fuel-nozzle pads. One user said he believes at least some broken bolts can be attributed to technician inexperience. The nozzle sits at a slight angle, he continued, and novice techs sometimes break off the bolt heads because they are not properly aligned and too much force is applied. Experienced techs have much greater success. Another user reported that his plant requires all of these bolts to be sprayed with an anti-seize first then broken loose using a box wrench to eliminate excessive force. Once the bolt is loose, the techs can use a socket wrench to remove them.
- Fretting and wear have been observed on tube sleeves at the strut exit areas. Cracks also are in evidence on the oil and vent tubes. Inspect regularly. Consult SL 5000-06-01 regarding replacement of oil tubes. A point made during the discussion: If the B-sump pressurization line is cracked, C-sump temperatures will be 15 to 18 deg F higher than normal. Not everyone agreed. Some users with this problem have not seen a difference in temperature; others said they believed the temperature change was more likely on the supply line than on the sump line.

Combustor. Burning/erosion on the trumpet edges and the combustor dome between the trumpets is seen on 100% of the combustors at 25,000 hours, and at 15,000 hours or less for units running on liquid fuel or with NO_x suppression. This is a continuing issue caused by insufficient or missing cooling air, malfunctioning or worn fuel nozzles, and combustor dynamics.

One user said his plant was running at maximum power and getting 50,000 hours on combustors and from 8000 to 12,000 hours on fuel nozzles. He made the following recommendations:

- Pull fuel nozzles as a set, recondition them, and flow-check every nozzle.
- Using a spec developed several years ago (it was handed out to participants and can be accessed by users through WTUI), ensure your fuel nozzles are in the lower one-third of the specification for steam flow and in the upper one-third in terms of fuel flow.

Keep in mind that every nozzle may pass the spec, but the set may vary widely across the spectrum of allowable values defined by the OEM. Tighter tolerances ensure that all nozzles in the set are consistent from a flow perspective, minimizing the probability of issues. A matched set of nozzles is critical for maximizing combustor and nozzle lifetimes.

HPT top issues included these:

- The dirt scoop associated with the first-stage nozzles surfaced as an issue for the first time in WTUI history at the 2013 meeting. This component, spot welded to the nozzle support during manufacture, is used in aircraft engines to filter out airborne particulates. While one could argue that LM2500s in generation service don't fly and therefore don't need a dirt scoop, its removal would alter engine design.

  Most dirt scoops are found cracked during inspection/overhaul and cracks are not allowed in this area according to IRM guidelines. Experts said the pressure balance in the 4B bearing is impacted by cracking in the nozzle support area where the dirt scoop is located. Three incidents related to the failure of this component have been reported. The bottom line: Crack repair is much less costly than repairs associated with a pressure-balance failure at the 4B bearing.
- Air tubes (a/k/a spoolies), retainers, and washers often are found worn, broken, or missing during inspection. Fragments have been found inside nozzle segments. The damage is believed related to the temperature difference between cooling air and the nozzle, as well as vibration. Users engaged in a

brief discussion on the subject noting that even when air tubes are broken they cannot migrate and cause additional damage.

LPT stator discussion focused on case cracking and inner seal wear.

- Axial case cracking has been found during depot inspections, with severe axial cracks observed on the TMF/LPTS flange seal. Because these cracks can be seen only after the LPT stator has been removed, they are thought to be heating/cooling related. There was only one event in 2012, but there were 14 axial cracks on the LPTS. Nozzles were removed to inspect further and the cracks were found to propagate circumferentially. They were outside IRM limits at the time and could not be repaired. A repair has since been developed.

  A user mentioned that the metal in his plant's turbine cases could no longer be repaired because of the number of heating/cooling cycles experienced. Welding of the cases was tried, but it just spider-webbed everywhere. The cases had to be re-skinned.
- Wear/grooving was noted on the inner seal. This can adversely impact cooling and may lead to TMF cracking. OEM instructions say no wear is allowed on the 10-14 spool-shaft configuration seals.

LM6000

Session chair and discussion leader for the LM6000 breakout sessions was David Merritt, deputy general manager of power operations for Kings River Conservation District; session secretary was Steven Giaquinto of Strategic Power Systems Inc. Depot presentations were made by TCT, IHI, and MTU. The LM6000 fleet now has more than 1000 engines in service, about three-quarters of those equipped with conventional SAC combustion systems, the remainder DLE.

This was Merritt's first year at the helm of the LM6000 track. He will not be at the front of the room in 2014 having been elected a vice president of WTUI. Andrew Gundershaug, plant manager of Calpine Corp's Solano Peakers, will have the gavel this year. He moves up from the LM5000 breakout, his position there filled by Perry Leslie of Wellhead Electric Co's Yuba City Cogeneration Plant.

A great deal of material was reviewed/discussed during the LM6000 breakout sessions. Some of the topics that generated significant interest include the four identified below:

No. 2R/No. 3R bearing. The root-cause analysis of an inlet gearbox failure on one unit that resulted in oil starvation at the No. 2R/No. 3R bearing was underway at the time of the meeting; first educated guess placed blame on a failed oil supply tube. Bearing surfaces revealed high-temperature discoloration.

Users asked the depot representative how you identify an issue in this area. Response: It's a tough one and very difficult to monitor by temperature, so look for other signs. The first sign typically is from the chip detector. Also, look for leaks at weep holes, look for wetting, look for oil coming out of the bushings, look at the AGB boot.

Sprint® nozzle tip-shroud erosion in the extreme can surface after only 5000 hours of operation and possibly initiate an HPC event. One incident discussed was thought caused by the wrong droplet size and/or amount of water. Attendees were reminded to verify the recommended calibrations of their water control valves; also, to check the condition of Sprint nozzles during semiannual inspections and overhaul the nozzles at every hot-section or major overhaul.

Compressor bleed-valve durability received significant air time. Currently, Honeywell International Inc is the only supplier for this component; it also has the only approved repair facility. Experience reveals that valves sometimes are being replaced at less than the 10,000 operating hours expected. Reasons include positioning errors from misaligned shafts caused by bearing failures or bushing wear, bearing failures attributed to poorly distributed loading, oil leakage caused by wear on actuator seals, feedback errors, etc.

Recommendations made by the depots: Make use of the rotable valve pool to reduce outage time and implement the software change recommended by SB-217 to reduce valve movement. Longer-term, alternative repair options are being evaluated and an improved valve design is scheduled for release next year.

The value of a multi-dimensional user group meeting, such as that conducted by WTUI, is that presentations and discussions identify issues that users might want to know more about and answers sometimes can be found in the exhibit hall.

Serendipitously, the editors stopped at A & I Accessory Ltd's booth and learned that its engineers had analyzed the root causes of the most common causes of premature bleed-valve failure and had developed what they consider a better bearing for the service—one with increased load-bearing capability and improved durability in the high-temperature service environment. Other enhancements were mentioned as well—all aimed at extended service life. Company representatives also mentioned that A & I offers a rotable exchange program of its own.

Several instances of oil leakage associated with the compressor rear frame were reported, with the number of events growing annually—nine in 2012. In three instances, engine removals were warranted. Distortion of the J clamp was the root cause.

More specifically, the P clamp bolted to the brazed J clamp "walks" on the wear sleeve, bending the J clamp while doing so. The "walking" was attributed to tube vibration combined with thermal expansion/contraction. Compliance with SB-236 was a suggested solution.

The three depot presenters divided up the published breakout notes that they had helped to prepare and ran through the highlights, taking questions along the way. The following bullet points identify the topics discussed. WTUI members can get more detail in the closed user-only section at www.wtui.com.

- Broken rear bolt on air collector. Look, in particular, at bolts near the 6 o'clock position where stress is highest.
- VBV actuation system failure investigation revealed that when the hinge gets loose, the door can't close correctly.
- HPT stator impingement-ring spoolie wear typically is associated with high-time engines.
- LPT first-stage nozzle burning and cracking has been observed. Check SB-255 and SB-273. Use of a thermal barrier coating helps mitigate the cracking issue. It was mentioned that owners will be able to purchase coated LPT modules in the future.
- T48 sensor failure is addressed in SB-230. Consult the SPS notes on the WTUI website.
- DLE combustor heat-shield separation caused downstream damage but engine trending data revealed no performance loss.
- XNSD speed-sensor failures caused by erratic or lost signals. Causes reported include poor electrical connection between the XNSD sensor and the LM6000's LP turbine speed electrical harness. Improvements suggested by the OEM are included in SB-262.
- LPC disc corrosion. In general, be sure to dry out your engine before shutting down after a water wash. Note, too, some S0 and S1 discs have been scrapped at the first overhaul because of bolt-hole corrosion and surface pitting. In the near term, recommended graphite grease for coating bolts should be used only on threads because of the product's strong correlation to galvanic corrosion. Engineering investigations continue.

- Avoiding HP compressor blade events—those caused primarily by FOD/DOD impacts and dovetail separations—usually can be avoided by adhering to recommended O&M practices.
- HPT first-stage shroud distress was identified on units at 6000 and 12,000 hours after hot sections. They were termed "strange" by the depot rep presenting. No conclusions were available at the time of the meeting. Interestingly, a user participant said, "We had this, too." The cause in his case was that the seal between the shrouds burned.
- HPT second-stage nozzles that had experienced issues and were improved by following the recommendations of SB-238 were said to have been in excellent condition during a shop visit. This led the depot to conclude that SB-238 was a good investment.
- LPT case rail wear can't be found during a borescope inspection, according to a depot rep. Depots are reporting many incidences, across all engine applications, of second-stage nozzles sagging into the case, caused either by rail wear or shifting shrouds. However, the issue is not as prevalent in the DLE fleet as in the SAC fleet. Repair is not simple if needed; you have to cut the CRF and re-weld it.
- Despite the educational effort, only about one-quarter of the attendees are currently tracking critical parts. However, while slow, progress is being made: Five or six years ago when the requirement was introduced, no one was monitoring critical parts. This program is particularly important for this engine at this time, because depots report scrapping parts because of cycles. Life limits help protect both personnel and the integrity of the engine.

LMS100

Session chair and discussion leader for the LMS100 sessions was Don Haines, plant manager, Panoche Energy Center, Firebaugh, Calif; session secretaries (note-takers) were Sal and Tripp DellaVilla of Strategic Power Systems Inc.

In his opening remarks, Haines said that the LMS100 operating fleet size had nearly doubled since the 2012 meeting, with fewer major issues being experienced. He then stressed the strong commitment LMS100 owner/operators have for information-sharing; its goal is continuous performance improvement across each plant and the overall fleet. To support this commitment, the group has established and strongly endorses the following forums:

- Users group conference call on the first Wednesday of every month at 1 pm Pacific. Contact Haines via www.wtui.com for details.
- Yahoo LMS100 Users Group, facilitated by SPS, to stay current on the various technical and logistical issues faced by owner/operators.

At the time of the 2013 meeting, 28 LMS100 units were in commercial operation; another 23 in the installation/commissioning phase. Of the latter, 19 are located at three sites in California. A tour on the last day of the 2014 meeting will be conducted at one of those facilities—the 800-MW, eight-unit CPV Sentinel Energy Project, located only five miles northwest of Palm Springs.

The high-time LMS100 engine has logged more than 30,000 service hours. Starting reliability for the fleet is nearly 99% according to ORAP data, based on information submitted for more than 80% of the engines.

A big difference between the LMS100 sessions and those for the other GE aeros was that there was no depot involvement. The OEM has staffed up and invested in tooling and facilities to handle the service requirements of this fleet. GE's status update on product improvement plans focused on the following issues:

- HPC first-stage mid-span shroud wear.
- HPC VSV system wear.
- SAC combustor durability.
- HPT first-stage blades.
- HPT second-stage nozzles.
- IPT strut tubes.

In addition to the GE presentations and open discussion forums, there were was a presentation on battery chargers by Sam Ayoubi of Alpha Technologies Inc, Bellingham, Wash, (available at www.wtui.com) and one on the Bently Nevada vibration system designed for the LMS100 by GE's William Trevino. CCJ

Upcoming meeting alerts on new issues, how to improve performance

The first major user group meetings of 2014, the 501F and 501G, are coming up fast. Both conferences will run concurrently from Sunday, February 16, through Thursday, February 20, at the Westin Mission Hills Resort & Spa in Rancho Mirage, Calif. The two groups will come together for discussions on issues of mutual interest, vendor fair, meals, and social events. About 200 owner/operators are expected to attend the annual event.

Russ Snyder and Steve Bates, who chair the 501F and 501G steering committees (Sidebar 1), respectively, shared conference highlights with the editors (Sidebar 2) to facilitate your planning. For updates, visit the websites of both users groups: http://501F.users-groups.com and http://501G.users-groups.com.

If you have not been to a 501F/501G meeting in the last few years, explanation of the term "vendorama" in the conference highlights might be beneficial. The steering committees invite technical presentations by third-party equipment and services providers serving the 501F and 501G fleets on Day One of the meeting. These presentations are vetted by the committees to assure content of value to owner/operators and to eliminate any promotional material.

The presentations program, which begins 10:30 am Monday, February 17, and ends about an hour before the vendor fair and reception at 5:15, is called "vendorama." Attendees receive schedule grid onsite. Last year, there were six concurrent presentations in each of the eight half-hour time slots. Typically, prepared remarks run 15-20 minutes and Q&A up to about 10 minutes. At least one steering-committee member attends each session to assure a timely start and end to the proceedings.

Exhaust systems

The value of user groups to gas-turbine owner/operators cannot be overstated. It is highly doubtful that this sector of the electric power industry would have matured so quickly had user

1. Steering committee

501F

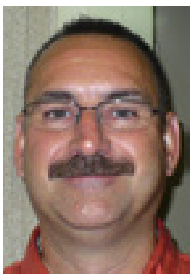
Chairman: Russ Snyder, plant manager, Acadia Power Station, Cleco Power LLC
Vice Chairman: Ray Martens, plant manager, Klamath Cogeneration Plant, Iberdrola Renewables LLC
Vice Chairman: Ivan Kush, director of technical services, Calpine Corp
Rene Villafuerte, plant manager, CCC Saltillo, Falcon Group
Carey Frost, 501F program manager, Duke Energy
Paul Terry, team leader, RS Cogen LLC, Axiall Corp
Martha Leskinen, principal engineer, Desert Basin Generating Station, SRP
Paul Tegen, chief CT/I&C engineer, Cogentrix Energy Power Management LLC

501G

Chairman: Steven Bates, plant manager, Wise County Power Co LLC, GDF Suez Energy Generation NA Inc
Scott Wiley, fleet maintenance manager, GDF Suez Energy Generation NA Inc
Greg McAuley, VP, Turbine Maintenance Group, Calpine Corp
Kevin Robinson, operations manager, Lakeland Electric
Dan Jorgensen, maintenance manager, Granite Ridge Energy LLC, Cargill Inc
John Wolff, technical support/compliance manager, PPL Ironwood, PPL Generation LLC
Mark Winne, plant manager, Millennium Power Plant, Millennium Power Partners LP

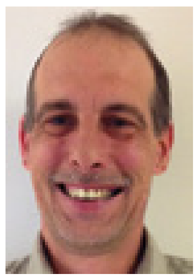

Bates

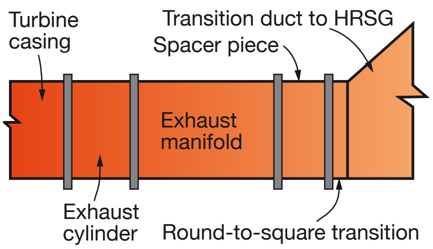

Martens


Robinson


Wiley


Winne


Wolff



1. W501FD2 exhaust system upgrades—such as a single-piece exhaust cylinder—make the back end equivalent to that of an FD3

groups not been formed years ago to help owner/operators share experiences, best practices, lessons learned, spare parts, etc. The all-volunteer user groups also have contributed significantly by collaborating with OEMs on behalf of owner/operators to help resolve fleet issues.

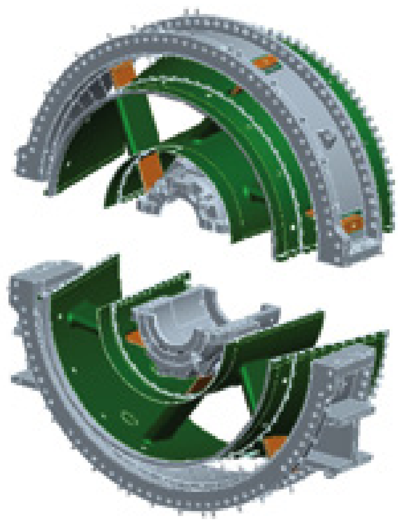
There are many specific examples of how user groups have contributed to the improvement of simple- and combined-cycle plants over the years. One that stands out in the 501F fleet is the exhaust system. The service histories of most, if not all, exhaust systems serving F-class and more advanced engines indicate the challenges posed by high gas temperatures and velocities, the need to cycle gas turbines more frequently than was anticipated at the design stage, and the desire to use the least costly materials available.

The 501F users began sharing experiences on the repair of cracks in exhaust manifolds, exhaust cylinders, and struts years ago (Fig 1). It was a lively topic at most meetings because virtually every repair that promised to be the "repair to end all repairs" never did—unrealistic expectations perhaps. A couple of users told the editors they had given up on ever having a permanent repair and had welders on call for annual outages to patch the system to the extent possible.

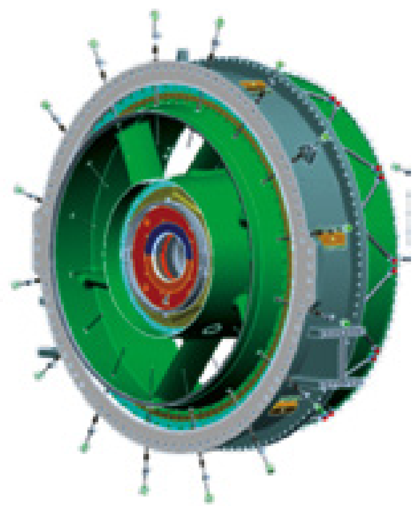
Examples of the extensive and detailed coverage given exhaust-system repair methods at the 2008 and 2009 meetings illustrate the collaborative mindset nurtured by the industry's user groups. Access this background material by scanning QR1

QR1

QR2



2. Advanced two-piece exhaust was developed as a drop-in replacement to address the durability concerns associated with the original component



3. Single-piece exhaust, SPEX, features a thermally unconstrained design suitable for some FD3 service upgrades as well as in new F4s and F5s

(2008) and QR2 (2009) with your smartphone or tablet.

While the users were investigating various repair techniques to resolve exhaust-system problems at least cost, the OEM was designing replacement systems to accommodate the operational realities of the day. Replacement alternatives for owners of 501FA, 501FC, and 501FD2 engines are the advanced two-piece (ATP) and single-piece exhaust (SPEX) systems.

The former (Fig 2) was developed as a drop-in replacement to address durability concerns with the original two-piece design. This is termed a "thermally compliant design" featuring materials upgrades and more robust cylinder cooling to reduce creep concerns. The first commercial installation of the ATP was completed in May 2012 during a major inspection outage. That exhaust system, heavily instrumented, has been running in base-load service since with data revealing no issues and suggesting engineering expectations are being met.

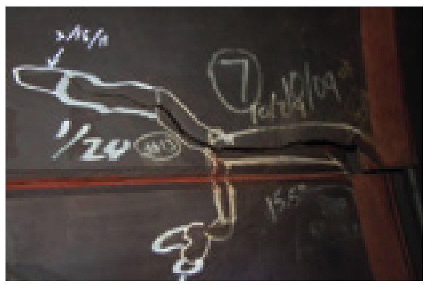
The SPEX, or single-piece exhaust, is of a thermally unconstrained design and specified as original equipment for F4 and F5 machines; some new FD3s were provided with it as well. It also can be retrofitted in place of the original two-piece exhaust on earlier models (Fig 3). More than three dozen SPEX systems are in operation, with the fleet leader in the neighborhood of 30,000 equivalent base-load hours. The OEM reported positive user experiences with the new system and showed a large number of complimentary photos taken during inspections.

Retrofitting SPEX to one of the early 501s is not a decision to be made quickly. There's a great deal of work involved in such a project, but some of the cost can be offset by upgrading R4 of the turbine at the same time and taking advantage of performance improvements.

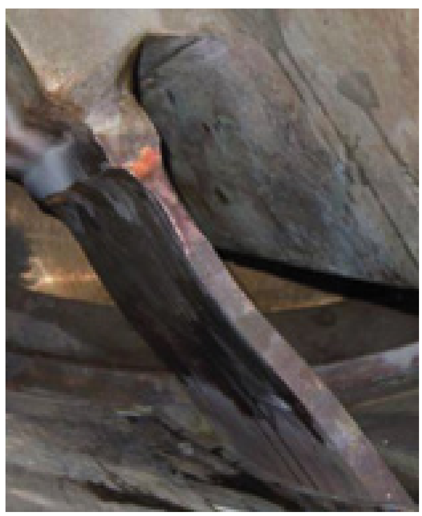
Klamath Cogeneration Plant was a pioneer in transitioning from the original two-piece exhaust cylinder to the SPEX/R4. Plant Manager Ray Martens, a vice chairman of the 501F Users Group, and his staff believed the single-piece exhaust cylinder offered a long-term maintenance advantage. Martens gave attendees a detailed description of the exhaust-system replacement and the accompanying performance upgrade project at the 501F meeting a few years ago (scan QR3).

QR3

With well over 100 engines in the 501F fleet as potential candidates for exhaust-system upgrades, interest in this topic remains high. At last year's meeting a user addressed the group on his plant's experience. It began in



4. Cracks only get bigger. During a strut inspection, engineers found outer diffuser cracks were growing



5. Crack in strut grew 2 in. within a month

2. Conference at a glance

Sunday, February 16

Morning

11:30	Sign in for golf tournament

Afternoon

12:30	Tee-off
5 to 8	Welcome reception

Monday, February 17

Morning

7 to 4 pm	Registration
7 to 8:30	Breakfast
8:30 to 9	Welcome and introductions, F and G users, closed session
9 to 10	Safety roundtable, F and G users, closed session
10 to 10:30	Morning break
10:30 to 12:10 pm	Vendorama, F and G users

Afternoon

12:10 to 1:05	Lunch
1:05 to 2:15	Vendorama, F and G users
2:15 to 2:35	Afternoon break
2:35 to 4:10	Vendorama, F and G users
5:15 to 8:15	Vendor fair and reception

Tuesday, February 18

Morning

7 to 4 pm	Registration
7 to 8	Breakfast
8 to 10:15	Siemens presentations for F users; closed session for G users
10:15 to 10:30	Break
10:30 to noon	Siemens presentations for F users; closed session for G users

Afternoon

Noon to 1	Lunch
1 to 2:30	Siemens presentations for F users; closed session for G users
2:30 to 3	Break
3 to 5	Siemens presentations for F users; closed session for G users

Evening

6 to 10	Siemens Event

Wednesday, February 19, F Users Program

Morning

7 to 4 pm	Registration
7 to 8	Breakfast
8 to 9:30	Mitsubishi presentation
9:30 to 10:15	Inlet and exhaust roundtable
10:15 to 10:30	Break
10:30 to 11:15	Compressor roundtable
11:15 to noon	Combustor roundtable

Afternoon

Noon to 1	Lunch
1 to 1:45	Hot gas section roundtable
1:45 to 2:30	Rotor and casings roundtable
2:30 to 2:45	Break
2:45 to 3:30	Generator roundtable
3:30 to 5:30	User group business

Evening

6 to 10	Mitsubishi Event

Wednesday, February 19, G Users Program

Morning

7 to 8	Breakfast
8 to 10:15	Siemens presentations
10:15 to 10:30	Break
10:30 to noon	Siemens presentations

Afternoon

Noon to 1	Lunch
1 to 2:30	Siemens presentations
2:30 to 2:45	Break
2:45 to 5	Siemens presentations

Evening

6 to 10	Mitsubishi event

Thursday, February 20

Morning

7 to 8	Breakfast
8 to 9:45	Separate closed sessions for F and G users
9:45 to 10	Break
10 to noon	Mods and upgrades for F users; closed session for G users

Afternoon

Noon to 1	Lunch
1 to 2:45	Siemens steam turbine session, optional for F and G users
2:45 to 3	Break
3 to 5	Siemens steam turbine session, optional for F and G users

fall 2010 when three cracked struts were repaired by the OEM, which provided a one-year warranty. Strut inspections were required every five starts. During one of those inspections, in January 2011, engineers found cracks in the exhaust manifold's outer diffuser had begun to separate and grow (Fig 4). Repairs were scheduled for the fall.

During a phased-array ultrasonic inspection in June, a 6 in. crack was found in one of the struts (Fig 5). Over the next month the crack grew by 2 in. and the unit was taken out of service. The OEM repaired the strut, but it warped during post-weld heat treatment and the back end of the unit sagged; it could not be realigned. The speaker said the plant considered these three options:

- Replacement in kind with a pre-owned exhaust system.
- Retrofit with SPEX.
- Retrofit with ATP.

Plant personnel viewed SPEX positively for its (1) availability (six-month delivery), (2) upgraded manifold and cylinder design and materials, and (3) potential for future thermal performance upgrades. Negatives included unknown performance without doing the thermal performance upgrades that Klamath did, as well as limited room for installation.

ATP presented no clearance constraints and also offered upgraded materials. However, there would be no operating experience with this design until mid-2012 at the earliest (serial No. 1 was scheduled for installation in spring 2012) and costs were not much different than SPEX. Also, this arrangement does nothing to improve exhaust-manifold materials issues and questions remained in the minds of plant personnel regarding dead-air-space cooling and venting.

In December 2011, following field inspection of manufacturing facilities, a SPEX was ordered for June 2012 delivery. The plant outage began in April with engine disassembly and replacement of necessary components. The exhaust manifold and cylinder were removed and scrapped. Generator was rewound.

Among the lessons learned:

- Purchase applicable tooling for SPEX installation.
- Buy extra bolting, Nord-Lock washers, and nuts for the bearing tunnel.
- Order radial vibration and blade-

path thermocouples. They are different than for the original exhaust system and lead times are long.

- Install bearing lift oil system.
- Follow manufacture of the SPEX carefully. This user found defects in strut shields and surface issues with new struts.
- Pay attention to the trapeze-spring can setting. Trapeze changes startup and shutdown characteristics; it does not dampen as well as the previous design.
- Flow changes from SPEX caused several new hot spots on ductwork to the heat-recovery steam generator.
- Existing fire protection system likely requires upgrades to accommodate the new bearing tunnel. An engineering and fire-code review effort is recommended.

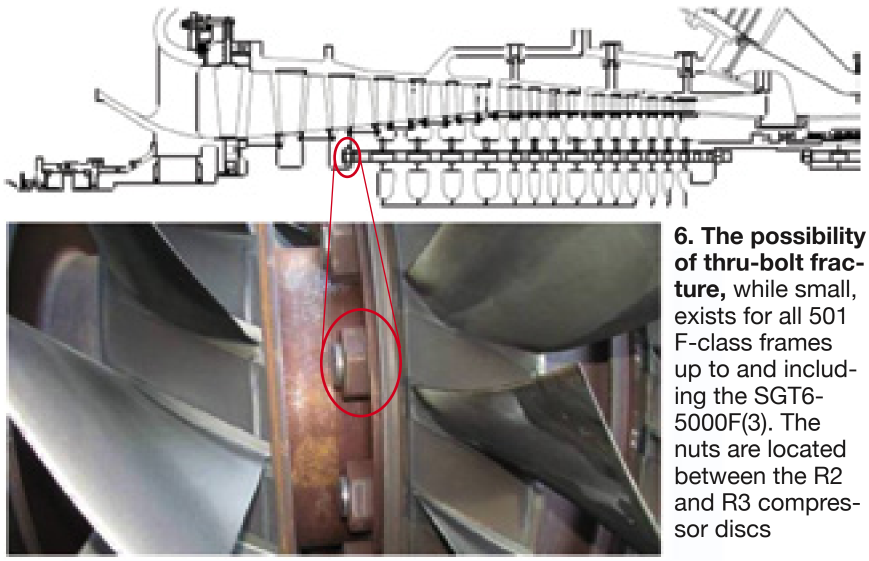
The exhaust system likely will be introduced as a discussion topic at the 2014 meeting. If you are considering an upgrade and have questions, bring them to the meeting. Several colleagues in attendance will have experiences to share; plus, Siemens engineers will be available.

Thru-bolt fracture

Another hot topic for the California conference will be the compressor thru-bolt issue on 501F models earlier than the SGT6-5000F(4). The OEM is currently discussing with customers changes coming for the bolt, the nut, and the disc. Be there to get the latest information first-hand. If you're a 501F (SGT6-5000F) owner/operator and not aware of this issue, you probably have not been attending user group meetings or reading OEM advisories. Most likely, you're new to Siemens engines. A quick summary to bring you up to date:

- One compressor thru bolt fractured on each of two gas turbines in this family of engines in 2012—six months apart. An indication was found in a third bolt during the inspection and destack of one of the two units with fractured bolts.

Note that only those compressors designed with 12 thru bolts are of interest. The latest machines, models designated SGT6-5000F(4), (5), and (5ee) have only one bolt and are not pertinent to this discussion. The failures occurred in the threaded portions of the bolts between the R2 and R3 compressor blades as shown in Fig 6.



6. The possibility of thru-bolt fracture, while small, exists for all 501 F-class frames up to and including the SGT6-5000F(3). The nuts are located between the R2 and R3 compressor discs

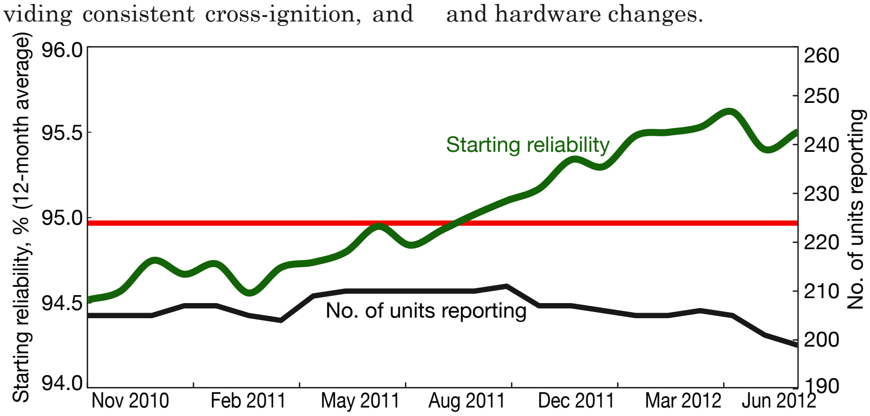
- The fractures were identified at two different operating conditions—one on load ramp, the other on turning gear. Flow-path damage was experienced on one machine. Each of the engines had accumulated more than 40,000 equivalent base-load hours and about 2500 equivalent starts at the time of their respective incidents.
- User discussions suggest crack initiation is at the first loaded thread and that a small flaw propagates quickly on such highly loaded bolts. One estimate is that failure can occur in only 300 hours after crack initiation. More detail: Thru-bolt nuts shift radially outward during starts, increasing the loading on threads at bottom dead center. High-cycle fatigue (HCF) damage accumulates during starts. Other possible influences on crack initiation may be one or more of the following: duty cycle, rotor configuration, assembly variation, and variations in material properties, among others.
- Investigation of the events continues. The OEM is conducting, for data-gathering purposes, opportunistic conventional UT inspections of compressor bolts at major inspections or any outage requiring a compressor-cover lift. Recommendation: Replace compressor thru-bolts and nuts following a compressor de-stack.

Starting reliability

Siemens reported that the starting reliability of its F fleet has increased by more than one percent in the last few years (Fig 7), most of that improvement the result of hardware and software changes to the engine's controls and fuels systems. Starting reliability continued to improve during 2013.

The software mods contributed to the reliability improvement by maximizing the ignition window, reducing startup gas-path temperatures, providing consistent cross-ignition, and minimizing the need for seasonal tuning. Regarding hardware, eliminating some regulator valves and maintaining constant mass flow with changing fuel-gas conditions have contributed to a reduction in maintenance and an improvement in starting reliability for units that restart with hot fuel. A new witch-hat strainer for all DLN fuel-gas stages has contributed to the reliability improvement by protecting fuel nozzles while being less susceptible to clogging.

The takeaway from this OEM presentation: If your starting reliability is not at least 95%, you can do better simply by implementing a few software and hardware changes.



7. Operational enhancements have had a positive impact on improving the starting reliability of SGT6-5000F engines. Note that starting reliability is defined as successful starts divided by attempted starts multiplied by 100

Debris mitigation

You wouldn't think that the accumulation of a little debris in the seal pin slots of R1 turbine blades would cause blade failures, but it did. The original configuration of the seal slot, at left in Fig 8, allowed debris to accumulate there and form a hard-pack which could cause seal pin-to-platform lock-up. This had a negative impact on blade frequency and allowed the initiation of an HCF fracture near the base of the airfoil. The slot back wall was reconfigured, as shown in the right-hand sketch, with positive results: There have been no R1 blade failures where this solution has been implemented.

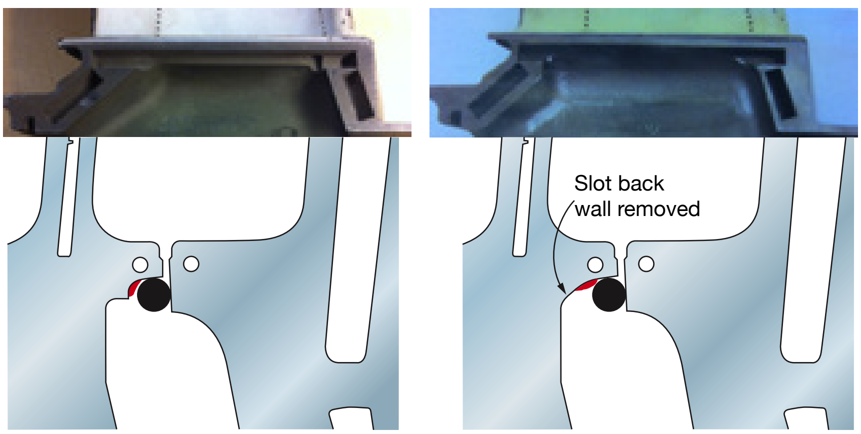
Aftermarket competition

The annual meetings of the 501F and 501G Users Groups are among the best industry events for conducting due diligence on engine parts, services, and upgrades, and for purchasing decision-making. The reason is simple: Two major OEMs, Siemens Energy Inc and Mitsubishi Power Systems Americas Inc (MPSA), participate and compete head-to-head to serve a global fleet of about 450 F-class engines. Both manufacturers get significant podium time at the conference and by listening carefully to each you can decide on questions to ask the other. No machine is perfect and competitors generally are willing to share what they believe is wrong with the other company's equipment.

PSM also is highly visible at the meeting, offering both parts and services for the F fleet. The leading third-party repair shops are there as well—including ACT Independent Turbo Services, Allied Power Group, and Sulzer Turbo Services—competing against the OEMs and PSM. The competitive battle focuses on business associated with the early 501F models—up to and including the 501FD2.

The Mitsubishi team annually updates attendees on the company's infrastructure and capabilities before discussing the specific modifications and upgrades it recommends to improve durability, reliability, availability, etc, of the 501F engine. At the 2013 meeting, the first slide traced the company's North American commitment from 2001 ($40 million, seven employees) through 2012 ($550 million, 1700 employees). Facilities installed during that period included the Outage and Resource Center in Houston, Power Generation Services in Orlando, MPSA Headquarters in Lake Mary, Fla, and the Savannah Machinery Works in Georgia. Profiles of each are available online.

Milestones in the development of

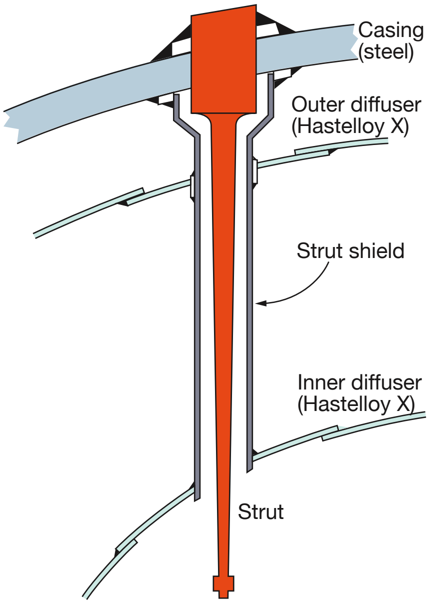


8. R1 turbine blade seal slot was modified to reduce the possibility of accumulating debris the 501F was another segment of the presentation and of particular interest to industry newcomers. Here are the highlights:

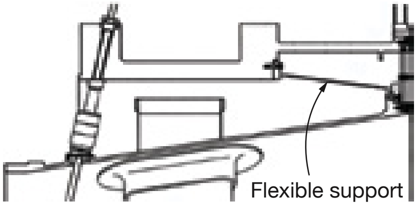
- 1984. Mitsubishi and Westinghouse Electric Corp agree to co-develop the 501F with a 1350C (2462F) firing temperature.
- 1985. Mitsubishi takes over the manufacture of large gas turbines for Westinghouse, which later closes its Lester (Pa) GT manufacturing facility.
- 1993. First 501Fs begin commercial operation at Florida Power & Light Co's Lauderdale Generating Station.
- 1998. Siemens acquires Westinghouse and the technology alliance between Westinghouse and Mitsubishi is terminated. Mitsubishi begins implementation of materials changes, structural modifications, and cooling enhancements to improve component durability at high firing temperatures.

The upgraded parts developed by Mitsubishi were installed in its M501F3 and later offered for the W501FD2. Company engineers presenting at the 2013 meeting focused first on the exhaust system issues experienced by many owner/operators in the room—such as cracking of the outer diffuser, strut shields, and struts. They believe at least some of the cracking can be traced to the design of the strut shield, which is welded to the casing, inner diffuser, and outer diffuser—and does not allow for thermal growth between the casing and diffusers (Fig 9).

The Mitsubishi speakers also pointed to the relatively sharp weld connec-



9. Strut arrangement on early 501Fs does not allow for thermal growth between the casing and diffusers



10. Exhaust section redesign by Mitsubishi in 2002 features sealing of dead air space, strut cooling, robust diffuser plates, and flexible support system

tions at the intersection of inner and outer diffusers and the strut shield, suggesting that smooth fillets would have been a better choice. Regarding materials, it was said that after the two OEMs went their separate ways, Westinghouse embraced the use of Hastelloy X for its outer and inner diffusers. One of its advantages was ease of welding. However, that material becomes brittle with age at F-class GT temperatures.

Mitsubishi stayed with stainless steel for the exhaust diffuser and increased its thickness in 2002. Plus, the flexible support system (strut shield is welded to the outer diffuser, not the casing, as shown in Fig 10), sealing off of the dead air space, and active cooling of the struts (an advancement based on G-fleet experience) all contributed to exhaust-system reliability and durability.

Modifications to the M501F two-piece exhaust cylinder to allow its use in W501F gas turbines were underway at the time of the last meeting with expectations that the first unit would be delivered in fall 2013. The Mitsubishi two-piece exhaust can be retrofitted into a Westinghouse machine during a typical major inspection plus three days.

Significant presentation time was devoted to the design features of individual 501F components developed by Mitsubishi that can be used in Siemens engines. Example: Mitsubishi uses assembled-type diaphragms rather than welded. Advantage is that mechanical fasteners increase vibration damping. First use was 1999, now well over 2 million hours of operating experience. Thicker airfoils were first used in a W501FD2 in 2008 in Rows 1-3 to increase structural rigidity; in 2010, in Rows 4-6. No evidence of hookfit wear has been identified to date. Come to Rancho Mirage and get an update.

Among the other components discussed were the following:

- Hybrid DLN combustor baskets, rated for 24,000 hours. The K-point DLN combustor was re-engineered; enhanced swirler mounting avoids swirler pin cracking. Ongoing work includes increasing flashback margin.
- Thick-wall transition piece introduced in 2002, now capable of 24,000-hr intervals. Increase in wall thickness and other design improvements reduced metal temperature and stress.
- R1 turbine blades. Changed material to directionally solidified MGA-1400, enhanced cooling to reduce oxidation loss, modified tip design. Looking to go beyond 50,000 hours.
- R2 turbine blades. Optimized cooling to reduce thermal fatigue, reduced stress concentration of cooling holes, increased fillet radius and trailing-edge thickness in platform, and new material all implemented in 2004 and meeting expectations.
- Turbine vanes. Moved away from cobalt-based alloy and Rows 1-3 now made from MGA-2400, which was said to have 100 times the creep strength of X-45. Also, cooling air optimized for R1.
- Root springs for use under R4 turbine blades eliminate blade rock in W501FC and FD2 units. Work continues on the development of a spring for R3.

You can't be too safe

The 501G Users Group, chaired by Plant Manager Steve Bates, GDF Suez-Wise County Power Co LLC, is a close-knit organization. Unlike most other user groups, it has a low percentage of first-timers. Almost everyone in the meeting room either knows most everyone else present or knows someone from his or her plant. Another factoid that sets the 501G users apart from the pack: Each plant in the fleet sends an average of two or three employees to the meeting. Most other groups average about one or less.

At the last meeting, the safety discussion, led by Bates, was robust and beneficial to virtually all plants powered by gas turbines. Here are some of the takeaways:

- Scaffold up as the outage progresses. Be aware that protection can be momentary, because as you progress in the outage, railings, etc, have to be added.
- Install a cabling system for tie-offs; it's tough to design a system flexible enough to accommodate several different engines and plant designs.
- Bear in mind that falls of even less than 6 ft can be lethal according to OSHA stats. Wearing a harness is a risk in itself because it can get tangled up, as can the tie line. Plus, workers can get tangled up in other's lines.
- Have a scaffolding crew onsite while work is ongoing, to provide safe access as the need arises. To keep the scaffolding crew busy, use them as part-time helpers to clean bolts, etc.
- Always look to make the scaffolding and fall protection better as the outage proceeds; be sure to take pictures and notes on what works/what doesn't to make the next outage safer. Verify that tie-offs to beams and piping are rated for the shock load. One user installed a supplemental beam system with full-column support to ground just for tie-offs.
- If you pull a harness from a bin, it must be certified before each use. If you issue harnesses to individuals, as most plants do, annual inspection and documentation is satisfactory. Identify harnesses by their serial numbers.
- Fire watch. The insurance company for at least one user requires a three-hour fire watch (periodic inspection) after hot work. Users agreed that they generally do it for 30 minutes, but for that duty, there's a watchman with no other duties except fire watch.
- Enclosure test for CO_2. If you lift the roof to check for proper sealing, run a fan test. Tough to pass the first time; the second time you do a better job of fit-up and sealing. A CO_2 dump test can cost upwards of $50,000, so most do not want to do that. Another suggestion: Put cameras in the enclosure to see if there's a fire inside before you enter.
- Evap-cooler doors can be difficult to open when need be. A pressure drop of 3 in. H_2O can be challenging. You can get that if a fog bank passes or if snow fouls the head end. Consider installing windows in the evap-cooler section so you can see what's going on in case you can't get inside. Also, put big grips on the doors because the standard chrome handle may not give you the necessary leverage. And be sure to install hold-open kick latches at the bottom of the doors.
- Confined space. Hire the local fire department for confined-space rescue standby when a plant is more than about 10 minutes away from emergency response personnel. Two benefits: Helps familiarize fire-department personnel with the plant and provides the FD another source of revenue.
- Every time job requirements change, reverify lock-out/tag-out requirements. CCJ

7F users weather a blizzard of information; Fuselier elected chairman

The first full day of the 7F Users Group's 2013 Conference, started on the double-quick and maintained that pace until the final bell. Chairman Sam Graham, maintenance manager at Tenaska Virginia Generating Station, cracked the whip on a user-only morning session that featured six content-rich compressor-section presentations and a lively open discussion on safety. The meeting broke precisely at noon and resumed 60 minutes later (Graham is navy punctual) with sessions on controls and auxiliaries. Vendor presentations followed the user-only portion of the program and they concluded a couple of minutes before the three-hour vendor fair opened at 5:30.

Graham didn't spend much time on his opening remarks—perhaps three minutes. There were more important things to do. The first was to thank Paul White of Dominion Resources Inc for his 15 years of service to the 7F Users as a member of the steering committee and one of the group's guiding lights during its development into a world-class engineering organization.

White has transitioned to an advisory role at Dominion and now spends a significant amount of time mentoring engineers and sharing best practices and lessons learned over his many productive years in the generation business. While some companies complain about the shortage of experienced engineers, Dominion is proactively addressing the issue with its mentoring program. Paul Whitlock of Dominion has replaced White on the 7F steering committee (sidebar).

Graham then passed the microphone to last year's chairman, Ben Meissner of Duke Energy, who updated

Steering committee, 2013 – 2014

Chairman: Ed Fuselier, Direct Energy
Vice Chairman: Richard Clark, SCE
Treasurer: Peter So, Calpine Corp
Jeff Gillis, ExxonMobil Chemical
Sam Graham, Tenaska Inc
Art Hamilton, Calpine Corp
Robert Holm, Occidental Chemical Corp
Robert LaRoche, SRP
Ed Maggio, TECO Energy
Justin McDonald, Southern Company Generation
Ben Meissner, Duke Energy Corp
Jim Sellers, Entegra Power Group
David Such, Xcel Energy
Eugene Szpynda, New York Power Authority
Paul Whitlock, Dominion Resources Inc

Whitlock So Graham Meissner Hamilton Holm Gillis Fuselier Giel Szpynda

Gross Such Clark Sellers

Steering committee for 2012 – 2013. Ken Gross of ConEd and Dan Giel of Duke Energy completed their terms at the close of the 2013 meeting. Robert LaRoche of SRP, Ed Maggio of TECO Energy, and Justin McDonald of Southern Company Generation were elected to the steering committee after the 2013 conference and are not in the photo

How to contact the 7F Users Group

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attendees on www.7Fusers.org, which went live just before the 2012 meeting. The organization's electronic headquarters hosts a lively, interactive 7F forum and is equipped with a fully searchable archive.

Both are accessible only by certified users—currently more than 700 from 75 owner/operators. The modern design and user-friendly website got two-thumbs up from attendees. If you are employed by an owner and/or operator of 7F engines and are not yet registered, do so today. This will give you access to presentations from the 2013 conference.

The big chill

Ed Fuselier of Direct Energy, the 7F Users' 2013 - 2014 chairman, gave what may have been the day's most uplifting presentation with an overview of the recently completed inlet-chiller retrofit at Frontera Energy Center, a nominal 500-MW combined cycle located in south Texas. The plant operates in an energy-only market, and with electricity prices generally highest in summer when temperatures are high, replacing the evaporative cooler with a chiller made good financial sense.

Frontera's inlet chilling system includes a 3.5-million-gal thermal energy storage tank (TES) rated at 70,000 ton-hr; the cylindrical steel vessel stands 65 ft high and measures 90 ft in diameter (Fig 1). TES provides significant operating flexibility (Fuselier called it a 60-MWh storage battery) while minimizing capital and operating costs. Specific benefits of the chiller/TES system include the following:

- Increases plant output by 53 MW on a 100F day.
- Halves auxiliary load during the day (5 MW versus 10) by storing energy overnight.
- Reduces capital cost. The chiller package is 7000 tons; 14,000 tons

1. Frontera Energy Center's new inlet-air houses feature outside egress on both sides (foreground). Chiller is to the left of the thermal energy storage tank would have been required absent the TES.

- Allows the chiller auxiliary load to fit on the plant auxiliary bus without an additional transformer.
- Enables the plant to run for two hours—so-called super-peak mode—exclusively on chilled water withdrawn from the TES tank (chillers not operating).

Innovation is evident in the inlet air house arrangement. The original inlet system was scrapped and a new inlet incorporating self-cleaning filters and chiller coils was installed by Donaldson Company Inc. Frontera wanted its new inlet system to fit on the existing structural steel to avoid disturbing the inlet bleed heat system and silencers. Another cost-saving goal was to avoid reconfiguring ductwork. This objective meant Donaldson would have to provide a unit with the same bottom-biased outlet transition that characterized the original inlet house.

But that is not ideal for chiller coils because, with this arrangement, more air would flow through the bottom-most coils than through the upper ones. Result: The upper coils would produce colder air than the bottom ones and the two temperature regimes would not mix before entering the compressor bellmouth. Such stratification is not permitted by the gas-turbine OEM.

The solution was Donaldson's "variable fin-pack density." Simply put, its engineers used CFD analysis to design the inlet with the optimal number of fins per inch on each coil to produce chilled air of uniform temperature on the downstream side of the chiller section.

Chillers are a competitive necessity for many plants in the Texas market. Given Frontera's location and the market served, chillers can operate at this facility a significant portion of the year. Temperatures at the plant site typically exceed 80F more than 3500 hours annually.

Although cold snaps are rare (temperatures are 50F and above about 8400 hours annually), their possibility was not overlooked by the owner's engineers. Should the temperature drop to about 30F, the plan is to circulate water from the cooling-tower basin through the coils to provide the heat necessary to prevent freeze-up. A water/glycol mixture will be circulated through the coils in the unlikely event the temperature drops to 25F.

Compressor session

Compressor presentations and discussion traditionally take most of the first morning at 7F User Group meetings and 2013 was no different. The session ran nearly three hours, including the coffee break. The other sessions—safety, controls, auxiliaries, combustion, turbine, and generator—typically are budgeted half that time or a bit less.

Catastrophic failure. It seems hard to believe, but a corrosion pit, so small that it's hardly visible, can bring down a large frame gas turbine. That was the sobering message from the first user to address the compressor session. Users may have heard this before, most recently in the CCJ from John Molloy, PE, M&M Engineering Associates Inc, in the 4Q/2012 issue, "Minimize the risk of catastrophic failure from contaminated inlet air" (access via the search function at www.ccj-online.com).

The case history presented to the 7F users described the wreck of a simple-cycle machine with 700 starts while it was at full speed, no load. Borescope inspection revealed extensive damage to the rotating and stationary compressor blades. But that assessment hardly described the damage found when the unit was opened and the rotor removed.

It did not appear that any airfoil was left unscathed. Close examination revealed only one clean fracture surface: An R1 blade was sliced off neatly at the platform. Investigators at the shop identified a second R1 blade with a big crack, perhaps only a few hours or one or two starts from failure.

The area in the lower casing once occupied by S5-S9 was cratered and occupied by slag. No one knew where the base casing material was. There was a deep gouge, about ½ in. deep and 6 in. long, in the mid compressor case which could not be weld-repaired. What to do about that?

There were three options for the rotor: rebuild the existing one, 10 to 12 weeks; buy a refurbished compressor rotor, five to six weeks; buy a fully refurbished unit rotor, four weeks. Casing options were: Repair existing casing, three weeks; buy a used casing, three weeks; order a new casing, 10 months. The casing repair option seemed contradictory because the OEM said welding was not possible. The owner opted for rebuilding the existing rotor and buying a used casing.

But the return to service would prove to be a torturous journey. The used casing was found, upon receipt, to have a patch ring at stage 10—an unpleasant surprise. Plant personnel learned that it was installed to correct a manufacturing error and that the casing had operated its entire life that way. The not-so-perfect casing, though disappointing, was accepted as is.

During re-commissioning operations the unit tripped on high exhaust spread. Debris distributed throughout the fuel system was the cause. It seems like workers "missed a spot" during cleanup. The debris hideout was on the upstream side of the purge valve. All fuel nozzles were removed and sent to a repair shop for cleaning and inspection; debris was collected and analyzed.

Root-cause analysis (RCA) suggested the failure was caused by the coexistence of a local high stress point and a corrosion pit which led to crack initiation and the eventual liberation of a single R1 compressor blade. Corrosion was likely initiated by poor water quality early in the service life of the unit, about the time of the millennium. A check of available records revealed that chlorinated river water was used as makeup for the evap cooler at that time. Today, a reverse osmosis system provides evap-cooler makeup and water quality is monitored.

One final note: Borescope inspections had been done regularly, the last one only a dozen starts before the wreck, but telltale pits and cracks had never been noticed because they were not in a "hot area" for inspection.

"Forced Forward Stator Replacement," well presented and well received, featured a valuable review of compressor issues and OEM responses (Technical Information Letters and product changes) that owner/operators have endured since the unit profiled began operating in spring 2005.

The historical perspective was of particular value to the first-timers in attendance—about half of the registrants. If you didn't absorb all that the speaker had to say, access the presentation at www.7Fusers.org. The archives section of the organization's website is for owner/operators only and requires a "library card." Register today online; it's simple to do.

The two 7FAs for this combined cycle were commissioned with the so-called "original" compressor blades and the OEM's modified water washing system. Given the many design iterations for these components it is difficult to understand from this summary exactly what was installed in this user's engines at the time. However, he did say that the airfoils in the R0 and R1 rows of his units were susceptible to erosion, foreign object damage, and associated cracking.

One of the reasons to attend user-group meetings is that you can query the speaker to learn exactly what components his or her case history is referencing. With all the OEM's design changes over the years, and the wide variety of third-party parts available, there probably are more than a hundred unique engines in the fleet.

Back to the case history. The plant

began inspections recommended in TIL 1509 for R0 and R1 in fall 2005. A crack was found in an R0 blade on one unit in spring 2008 and blades were replaced with the "original" airfoils. The owner implemented the OEM's recommendations based on fleet and user experience, including the following:

- No R0 upgrade.
- No online water washing.
- Aggressive semiannual inspection schedule.
- Monitor the OEM's upgrade progress through the 7FA Users Group and the GE sales team.
- Evaluate third-party solutions.

In planning for the fall 2011 major inspection, the owner's engineers fully evaluated all upgrade options, including the OEM's "enhanced compressor" upgrades—such as Package 3 to address R0 and stator failures, Package 5, marketed as a "proactive enhancement" to address R1 cracking and other issues.

In conducting its assessments, the outage team focused its analysis on issues presenting the highest operational risks—including R0/R1 cracking, stator cracking, aft stator rocking. Analyses complete, the owner, a transactional customer, opted to wait until it had adequate time to evaluate field experience with both OEM and third-party alternatives before deciding on the specific upgrades to install.

When Unit 1 was opened for the fall 2011 major, extensive corrosion pitting from contaminated air was in evidence on blades in R1-R3, R6, and S1-S4; some pits exceeded the maximum allowable depth after prescribed corrective blending. The pitting photos shown by the speaker were very similar to those presented by M&M Engineering's Molloy in the article referenced above.

The user presenting said his 18-stage compressors suck in air heavily contaminated by vehicular emissions and salt. He also mentioned a four-month shutdown in spring 2009 to address problems with the HRSGs. During that time there was considerable air flow (natural draft) through the gas turbines. Experience of others suggests that air curtains and portable dehumidification systems are beneficial. The owner also believes that ineffective water washing contributed to the pitting attack.

The poor condition of the compressor air path required a significant increase in scope for the major inspection. Re-blading was necessary. Plant personnel considered themselves lucky because no blades were liberated despite the extensive pitting. GE was selected to destack and overhaul the rotor and rebuild it with new blades, a job that took six weeks. The speaker said there was not adequate time to evaluate the capabilities of third-party services providers and invite them to bid on the work.

The plant had a spare rotor (with an enhanced R0), so it was inserted into Unit 1 and that engine's rotor overhauled for Unit 2 during its major inspection in late fall 2011. Unit 2's compressor also had extensive pitting damage. Interestingly, the plant is now operating two GTs with rotors having different features: One has a Package 5, the other a Package 3.

Follow-on corrective action includes the following:

- Increased frequency of water washing to multiple times weekly. R0 erosion is being monitored.
- Inlet inspections are characterized by greater vigilance for oil, dirt, grease, moisture, etc.
- An air-filter upgrade program will be complete by year-end.
- Upgraded water washing system is being evaluated. Investigation of erosion potential is part of the evaluation.

A second presentation by this user described "Aft Stator Replacement" for the same gas turbines. Since 2006, he said, semiannual inspections have been conducted for compressor rubs and shim migration; TILs 1502, 1562, and 1769 were mentioned. In 2008, a "cases-off" hot-gas-path (HGP) inspection included aft blade tip blending, installation of third-party S17 vanes and exit guide vanes, and pinning of shims by a third party.

The first significant finding of stator rock was during the fall 2009 borescope inspection. Rocking of from 30 to 50 mils was in evidence. The following spring, rocking of up to 67 mils was found. Inspection intervals were reduced to between 1000 and 2000 hours from that point on. Vane rock increased to as high as 95 mils. Owner was concerned because at 120 mils the gas turbine must be shut down.

Engineers set about evaluating upgrade options for the aft stator section of the compressor for possible implementation during the fall 2011 major inspection. The first option, replace in-kind, really was not a viable alternative: It doesn't solve the problem because the case was already damaged and the likelihood of shim migration was good.

The OEM's so-called Bigfoot mod/Package 4 was an alternative, but that was viewed as an extremely intrusive and permanent machining procedure that would become the critical path for the major. It also involved a significant upfront commitment for parts and labor for a procedure with limited operational experience (fleet leader at 13,000 hours at the time). Plus, there were emerging stator twist concerns.

A fallback position would be to wait until the 2014 HGP to implement a solution, as was the strategy described earlier for the forward stator section. But a third-party was offering multiple-vane segments using field-validated airfoils that were viewed positively. Fleet leader had 24,000 hours at the time and these parts and their installation were much less costly than the OEM's solution. Deal! The new parts have since passed the 12,000-hr mark and are said to look like new.

Another compressor presentation that got high marks, "17th-Stage Compressor Wheel Dovetail Cracking," provided attendees several lessons learned/best practices. When preparing for a major inspection, an owner's engineers were warned about the possibility of finding dovetail cracking on the 17th-stage wheel. Rotor out, cracks ranging from about 125 to 155 mils radial and 60 to 220 mils axial were illuminated by red dye on the aft side of every flat-bottom blade slot. The rotor had experienced 2025 actual starts and had recorded 44,365 hours of service at that point in its life.

The OEM told the owner to blend-out cracks up to a depth of 100 mils; also, to smooth all blunt edges and transitions of the blend and dye-pen the affected area to be sure the indication is gone. If a crack remains after blending 100 mils, the OEM said, take a picture, estimate the size of the crack, and submit a PAC (Power Answer Center) case. One crack was known to exceed 100 mils, so the owner leveraged EPRI research and decided that blending to 125 mils was acceptable.

Caution: At the 2012 meeting, an attendee told the group it was his understanding that if you blend and can't remove the crack it will propagate faster than if no blending had been done.

The forward sides of all slots also were dye-penned; all of those were cracked as well—from about 60 to 155 mils axial. EPRI's stress analysis concluded that 7FA discs with flat-bottom dovetail slots will crack somewhere in the neighborhood of 1000 to 1500 actual starts. The disk examined was considered good for another 900 factored starts.

A field service team from Sulzer Turbo Services was dispatched to the plant to blend out the cracks. This is a difficult job to do in the field, the speaker said, but Sulzer successfully removed all cracks. The owner's plan is to order the new 17th stage wheel/stub shaft with round-bottom blade slots and install it during the next HGP, which becomes a major because the rotor must be unstacked.

An RCA revealed that rim dovetail cracking is caused by thermal transient stresses associated with cyclic operation. Hot restarts are the most damaging operating scenario; during a shutdown, the rotor rim cools quickly and the wheel center stays hot. One user in the audience commented that rim cracks are not self-arresting. He added while round-bottom disc slots avoid stress concentrations characteristic of flat-bottom slots, they also will crack, but are expected to last twice as long as discs with flat-bottom slots.

There were two brief compressor-section presentations, one with the speaker talking through a series of photos of S17 vane segments from the time they were removed from the engine for repair of the bolted shroud until they were reinstalled in the unit. A hiccup was reported on final fit-up. A poll of attendees revealed about half a dozen users operating with shrouded S17 vane segments provided by a third-party supplier—one engine having more than 25,000 hours on those parts.

A user who presented last year on the difficulty in extracting damaged R0 blades using a come-along and air hammer, and the galling of the blade slots experienced with that method of extraction, was back at the podium again this year. He reported success (no galling) on another gas turbine by using a cutting wheel to remove the airfoil and then a milling tool to evacuate the blade slots. He said it took about three shifts to mill out all of the R0s. Outside California, he added, you can use a plasma torch and probably get the job done in one shift. The first rotor goes to the shop this fall to replace the stub shaft and integral wheel with the galled slots.

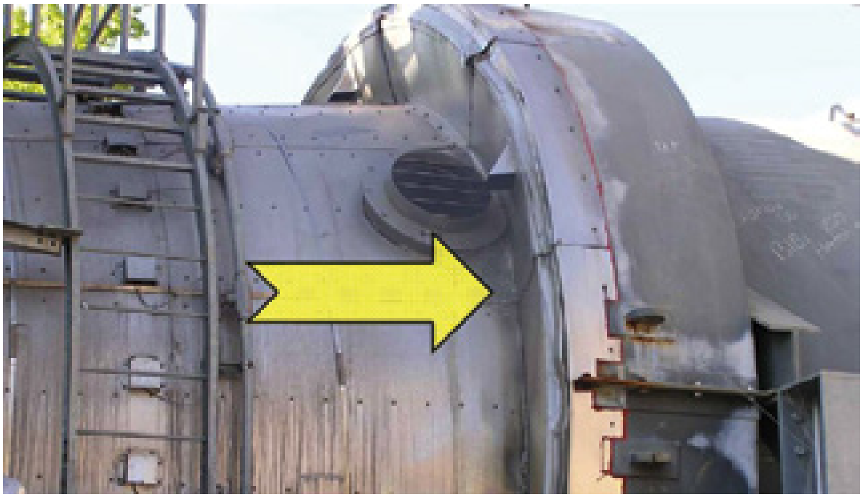
By show of hands during the open discussion period, about 80% of the group has done a compressor upgrade of some sort—most with the OEM. Other talking points included ice damage on R0 and how to avoid it. This has been a discussion subject at several user group meetings over the years. Use the search function at www.ccj-online.com to access more information. There also was mention of systems for compressor-blade health monitoring—both OEM and third-party—but relatively few attendees had experience with these promising diagnostics.

Safety

Fall protection was a major topic of discussion because many serious injuries result from falls of only a few feet. One fatality reportedly was caused by a 12-ft fall. Lifelines, suggested tie-off points, etc, were included in the give-and-take.

The pros and cons of enclosure entry while the GT is in operation also were debated. Some attendees see the benefits of periodically inspecting the inside of the turbine enclosure to identify leaks, catch other developing concerns, and to facilitate troubleshooting.

Others argued that opening compartment doors could put individuals at risk should unexpected conditions inside the compartment expose personnel to hot gas, a combustible environment, fire, or other acute hazards. They do not allow operators to enter the package with the GT in service. One case history noted involved an operator who opened the compartment door and saw something glowing in



2. Corrosion and discoloration of the metal shroud are indicative of a failing flex seal (above)

the combustion section (caused by the failure of a dual-fuel nozzle), narrowly avoiding injury.

An attendee said operators at his plant periodically open the compartment door for a 30-sec look-see to identify possible issues using the senses of sight, smell, and hearing. But they are not allowed to break the plane of the package with equipment in service. Another user said his plant allows operators to enter the package but they must be wearing a long-sleeved shirt and gloves, and inform the CRO before entering and after leaving.

The dangers of CO_2 fire extinguishing systems were discussed as well. One user's experience was that when CO_2 dumps into the No. 2 bearing compartment it spills out and floods the surrounding area. This can be dangerous because low-lying areas can take considerable time to ventilate properly. He recommended conducting a CO_2 test and tracking its migration to develop appropriate safety procedures. A recommendation from another user was to install hazardous gas detectors outside the package to improve their reliability.

Two more safety topics discussed: (1) Emergency exits and fire breaks in air-inlet filter houses, and (2) extraction of injured workers from confined spaces. The latter can be particularly challenging if the people who must be rescued are overweight. Regular practice with first responders was suggested.

Combustion session

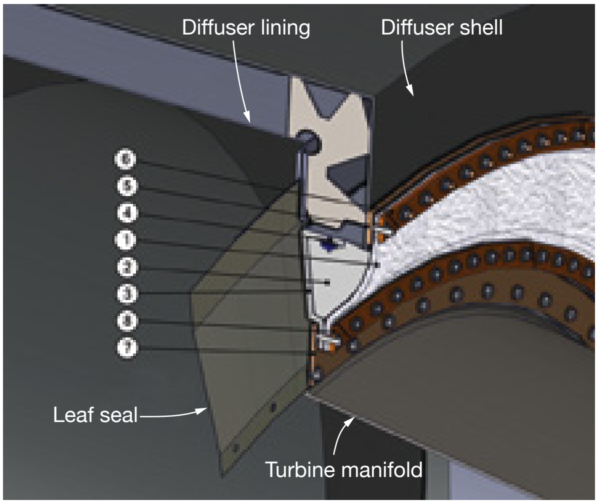
An owner reported that one of its 7FA.03s, with a DLN2.6 operating on LNG, tripped on high exhaust spread as the combustion system transferred from Mode 4 to Mode 6. A restart was attempted with the same result. First thought was that the root cause was in the fuel system, not the combustion hardware. Reason: Nitrogen in the LNG boils at -320F, lower than the -258F for methane, and engineers surmised that nitrogen vaporized first, rapidly diluting the boil-off gas (that is, the surge in nitrogen reduced the calorific value of the fuel at the burner tip).

Engineers believed this was the cause of the lean blowout (LBO) event, but because the Modified Wobbe Index was in the flammable regime at the burner tip, they predicted a DLN issue in addition to low MWI. The OEM was consulted and what sounded like a trial-and-error approach to a solution was initiated. The PM3 split was increased at the mode change and this was effective in avoiding LBO, but peak-2 dynamics increased as a result. Engineers also learned that peak-1 dynamics increased with MWI and peak-2 dynamics decreased with MWI.

Finally, engineers were able to tune the combustion system to hold dynamics under 2 psi, maintain NO_x between 10 and 15 ppm as allowed by the plant's permit, eliminate the LBO threat, and permit turndown to about 50% load. The editors spoke with the presenter afterward and learned his employer—a gas company that also produces electric power—saves the highest-value LNG for its gas customers.

The owner receives LNG from many sources worldwide and product variability can be significant in terms of its use in finely tuned combustion systems. A review of CCJ's EcoElectrica LP plant report, published in 4Q/2012, shows the highly reliable operation of that plant depends significantly on its high-quality LNG with minimal variation in composition.

Another presentation focused on the conversion of an early (Serial No. 1) 17-in. DLN2.6 combustion system to an 18-in. system. This was done to enable parts compatibility with other units and the ability to use 24K hardware offered by the third-party supplier with which it has a long-term parts agreement. The speaker attributed much of the challenging project's success to fellow 7F users who shared lessons learned from their conversion experiences. The presentation triggered significant open discussion on experience with 24K and 32K hardware.



3. The upgrade incorporates the following component parts: 1, belting; 2, Superwool insulation; 3, pre-bolster; 4, stud and washer; 5, cold-side flange; 6, cold-side back-up bars; 7, hot-side flange; 8, hot-side back-up bars

4. Completed flex-seal upgrade

Turbine session

Several discussion topics gained traction in the turbine session. Cracks in gas rings received some air time. One user said the OEM got involved the second time the PM3 header cracked on one of his units in the same location the occurred the first time. First thought was that vibration was the root cause of the problem because the upper section of the header was not supported to allow for expansion. But the gremlin turned out to be pigtail lockup. Upper-half pigtails were swapped out for ones an inch longer and the problem went away.

As the fleet ages, owner/operators are experiencing exhaust-frame deterioration as earlier frames had in the past. Condition-based maintenance was batted around and the general conclusion is that it's not there yet. A user described the scenario where the contractor decides what repairs to make by virtue of the contract. Your equipment might not be returned to as-new condition, he said, it might just be "good enough." Then the contractor loses the paperwork on what was done, what parts were used, etc. The owner is at risk then, he concluded.

The subject of exhaust-section flex-seal failures was brought to the floor. In four years of operation, one user's 7FA.03 had suffered several flex-seal failures. Another owner confirmed that failures do occur frequently. Yet another recommended changing the flex seal at every HGP inspection because, he said, "it will fail" and you don't want that to happen during the summer run. Proactive replacement is a viable strategy, he added.

That the vendor fair is a valuable adjunct to user group meetings was in evidence again as a stop at the EagleBurgmann booth revealed an OEM-approved flex-seal upgrade that seemed to address the needs of a couple of users discussing the challenges they faced during the closed session. Discoloration and corrosion of the metal shroud that covers the flex seal—located between the turbine manifold and exhaust diffuser—is indicative of a failing seal, the editors were told (Fig 2).

He said that the harsh cycling conditions experienced by many engines in the fleet cause flex seals to lose their flexibility and sealing capability over time. A leaking flex seal can allow exhaust gas to bypass the downstream SCR and contribute unnecessarily to NO_x emissions. The upgrade described in Fig 3 provides a gas-tight seal over the 7FA's existing metal flex seal (Fig 4).

Generator session

Floating hydrogen seals were a topic during the open discussion period. A few users were puzzled by the problems experienced on GT generators that had not been identified with generators at conventional steam plants. Recommendation: When you receive new hydrogen seals, make sure you check for roundness before putting them on a shelf in the warehouse. One plant went through six sets before finding one that met spec.

To pull the field periodically or not—at each major, for example—also was discussed, with no definitive conclusion being reached. The hands-on people in the room were for periodic field removal, saying an up close and personal inspection provides better information than GE's Magic (the acronym for miniature air-gap inspection crawler) or alternative remote inspection devices.

After the session, an attendee stopped the editors to say his plant had been quoted about the same price for Magic as for pulling the rotor, so they pulled the rotor. That was not the experience at a plant recently visited by the editors during its generator inspections. There the cost of remote inspection (not GE) was half the cost of pulling the field.

Controls session

The controls component of the 7F Users Group meeting has expanded in scope over the last couple of years to help owner/operators address multiple challenges—including diminished OEM support of legacy control systems and the need for tighter operational control to accommodate renewables, satisfy NERC CIP requirements, reduce emissions, etc. Several recent additions to the steering committee with controls experience have contributed significantly to the more robust program.

There were several user presenters in this portion of the 2013 conference. One focused on frequency response for combined cycles using the DCS. The speaker said the DCS emulates the governor and the preselected load set point is biased in proportion to the change in frequency. Critical to success is a high-resolution frequency measurement; the SFL1 in the Mark V or Mark VI via PI is not satisfactory. The solution here was to hard-wire a frequency meter to the DCS.

Another user presented on the value proposition of PI ProcessBook™, which makes it possible to efficiently display real-time and historical data residing in the PI system and other sources. He views ProcessBook as an efficient method for getting the most out of PI. Its advanced features are real simple to use, he said, and demonstrated this. Example: Scatter plots, good for identifying highly correlated items and for revealing when a process is off-track, are easier to build in ProcessBook than in Excel. If you're unfamiliar with ProcessBook, there's plenty of material up on the Web.

Upgrades. It seems that the most popular controls presentations at user group meetings concern system upgrades and replacements. One user presented on an HMI replacement for a combined cycle that began commercial operation in 2004. The original arrangement featured six GE HMIs and three screens in the control room. There was no HMI for use as an engineering work station (EWS). The new set-up features three of the OEM's HMIs: two in the control room and one EWS. All machines are quad-monitor capable, the speaker said. There are still three monitors in the control room; the EWS has two monitors.

Another upgrade to the original system was the addition of a Wyse terminal (thin client) to the Packaged Electrical and Electronic Control Compartment for each gas turbine. The PEECC, sometimes shortened to PECC, is where the Mark VI and the motor control center for the GT reside. The inexpensive Wyse terminal is connected to the Ethernet loop for the HMI and Mark VI. The reconfigured and upgraded system has been in service for more than a year; no negatives were reported.

The replacement of Mark V control systems on two gas turbines serving a combined cycle that started up in mid-2005 was the subject of another presentation. Interestingly, the Mark V had reached end of life (EOL), according to the OEM, in March 2004—more than a year before plant's commercial start; the announced end-of-service (EOS) date is March 2014. The owner felt compelled to upgrade. By way of background, the Mark V TMR system has four processors (referred to as cores) R, S, T, and C and a protective core P. It was initially provided with an IDOS <I> operator system and subsequently with a Windows/Cimplicity-based operator interface system and uses an ARCnet-based communications protocol to communicate with the operator interface system.

The owner's engineers reviewed many options, including the following:

- Upgrade to Mark VI with its 32-bit computer system, Windows interface and better software tools, and Ethernet-based communications. However, this system reached EOL four years ago and EOS is expected in only six more years.
- Replace the Mark V with a Mark VIe. Advantages of the latter include (1) OEM's current offering, (2) support expected until 2025 or beyond, (3) Windows HMI interface, and (4) Ethernet communications. Another benefit of a new Mark VIe is that it can be expanded to provide total plant control.
- Mark VIe migration (Mark V retrofit). This option involves installing a Mark VIe controller inside the Mark V cabinet and retrofitting it to the Mark V core. All boards are upgraded to supportable versions.
- Third-party DCS. The plant has Ovation™ for its balance-of-plant platform.
- Third-party solution with PLC-based controllers.

What to do? Perhaps the most obvious option would be to do nothing. Reasons include these: There are many Mark V systems operating in the electric power industry, the OEM will support the platform until parts run out, the OEM does offer field-service options (if you have the money, the OEM has a service team ready to support you), there is robust third-party support for control system components, and there's access to support from other owner/operators via the 7F Users Group.

A replacement Mark VIe apparently was on the pricey side, although the speaker did not talk about dollars or contract terms and conditions, as is the rule at user-group meetings. One assumed cost was a concern because he said field I/O work was required for a new Mark VIe and outage time would be a week or two, possibly more.

Ovation was a serious consideration, but, in the end, the lack of experience of that platform on 7F engines was the deal breaker—this despite excellent reviews from the one customer based on two years of service. Little was said about the PLC-based option.

The preferred solution for this application was a Mark VIe migration because of the speed and economy of implementation, and OEM controls reliability and compatibility. Regarding the second point, minimal control system management was required, the OEM support network was already established, and there were multiple third-party options for control systems, automatic tuning, flame monitoring, etc.

Value of the vendor fair. The editors stopped by CSE Engineering Inc's booth on the exhibition floor to ask what its team of experts would recommend to a critical generating facility having legacy Mark V controls on its GTs and then compare that solution with the one selected by the owner who had presented earlier in the day. Perfect question for Chairman Craig Corzine, a former GE employee having a deep background in Speedtronic® control systems and gas turbines, but he was out in the field. VP/GM Steve Morton was patrolling the company's 8 × 10 ft territory. Like many 7F attendees, he had served in the US Navy and managed shore-side generation facilities.

Morton said CSE, which celebrated its 20th anniversary in 2013, had decided not to develop a retrofit control system package for the gas turbines but to continue development of CSE's technology to extend the commercial viability of the existing Speedtronic control system with specific emphasis on the Mark Vs. Asked about CIP compliance, Morton said the concern with CIP standard compliancy is not related to the Mark V itself but to the HMI interfacing with the Mark V and it is one of the areas that the California company has focused on.

Corzine was patched into the conversation by cell phone and he said that scrapping the Mark V on a controls refurbishment project was akin to throwing out the proverbial baby with the bathwater. If it was installed, commissioned, and has been maintained properly, it's an exceptionally reliable system, the controls expert said. Spare parts and technical support are available and will be for several years to come. The only reasons to replace a Mark V in his view probably would be to accommodate a technological upgrade of the turbine—such as a DLN retrofit—or to transition to a fleet platform to reduce spare-parts inventory and to facilitate maintenance.

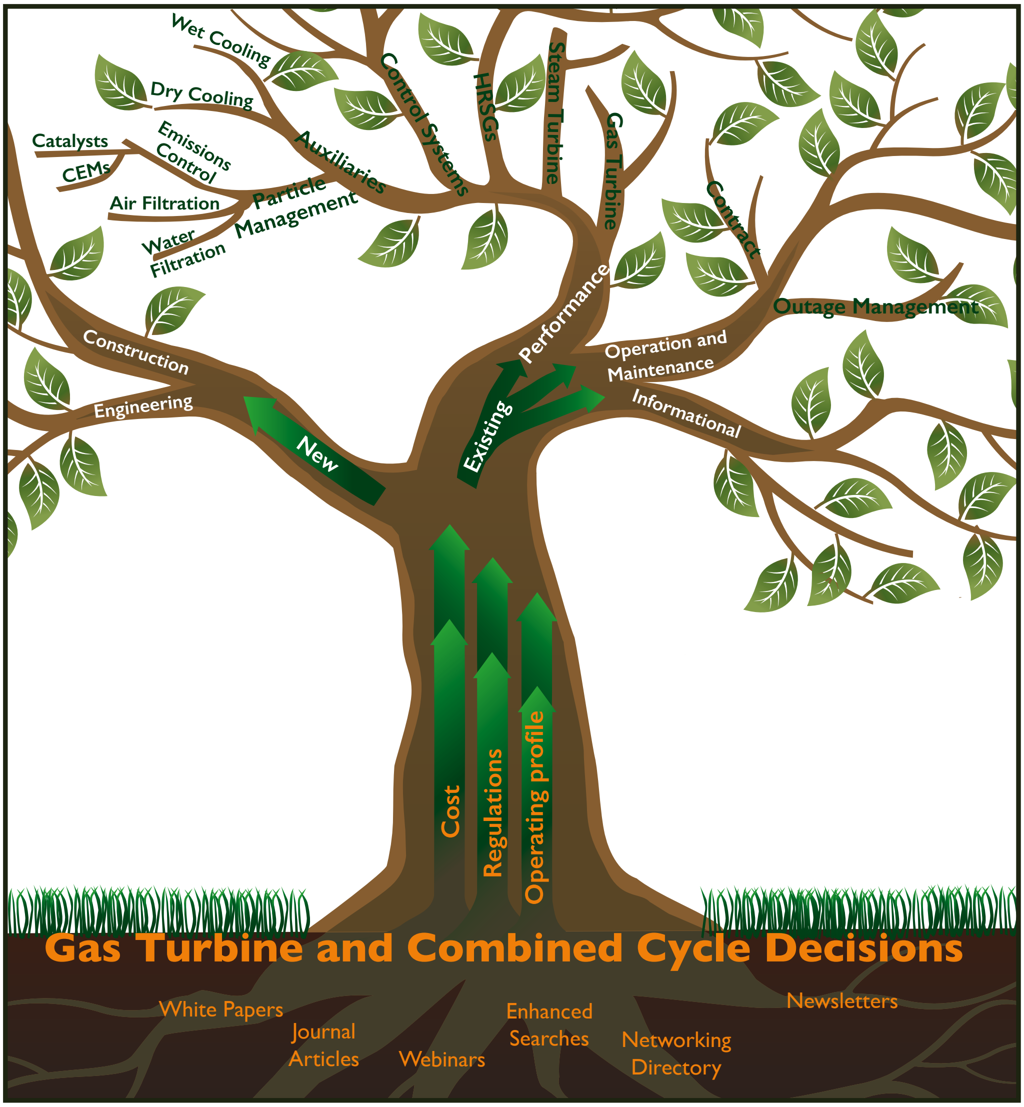
Corzine said CSE's <ITC>® HMI is a CIP-compliant industrial monitoring and control software platform designed specifically to replace the functionality of the IDOS based Mark V <I> and Windows/Cimplicity-based Mark V HMI. The <ITC> system also is used to interface with the Mark IV and Mark V LM, and soon for the Mark VI and Mark VIe as well.

The system communicates with the Mark IVs and Mark Vs using its native protocol over ARCnet and is provided with USB, PCI, PCIe, and Ethernet communications drivers. Plus, it can support up to four individual ARCnet networks and can be used to integrate Mark IVs and Mark Vs within the same system.

For the Mark V, <ITC> incorporates all the functionality of the legacy <I> and current Cimplicity-based HMI systems, inclusive of Logic Forcing, Control Constant Editor, I/O Configuration, Control Sequence Editor, EEPROM Utilities, Diag_C, View Tools, and Auto-Calibrate. Additional features not available with the standard <I> or Cimplicity-based HMI system include Automatic F Drive Synchronization across all <ITC> systems, fully animated Real-Time Rung Display with sophisticated search and navigation tools, Multi-generator Tie-Line Control, Integrated Data Historian, Integrated Time-Sync Manager for all Mark Vs and balance-of-plant individual controllers, and integrated offsite remote monitoring and control.

Additionally, the <ITC> system is used extensively as a data historian and gateway between the Mark V and other computers or control systems, providing a direct read/write data exchange path between the devices for monitoring and control. Communications protocols include OSI PI, OPC (server and client), GE FANUC Series 90 (Serial and Ethernet), Allen-Bradley DF1 (Serial, DH+, and Ethernet), DNP 3.0 (Serial and Ethernet), Modbus (Serial, Ethernet TCP, Ethernet UDP, and Modbus Plus), Siemens S7-200, S7-300, and S7-400 (Serial and Ethernet), Westinghouse WDPF, and many more. CCJ

Gas Turbine and Combined Cycle Supplier Program



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- Continuing interaction with end users
- Contacts and project tracking with continuing updates
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For more information on the Gas Turbine and Combined Cycle Supplier Program go to http://www.mcilvainecompany.com/GasTurbineMarket.htm or contact us at:

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IAPWS helps plants control cycle chemistry

One of the benefits of attending last fall's Air-Cooled Condenser Users Group meeting in Las Vegas was a review of guidelines for the operation of steam/water circuits in combined-cycle plants available through the International Association for the Properties of Water and Steam. Owner/operators worldwide can benefit from learning more about how this international non-profit association of national organizations can help them extract top performance from their Rankine cycles.

Dr Barry Dooley, a senior associate at Structural Integrity Associates Inc, and the executive secretary for IAPWS, brought attendees up to date on the Technical Guidance Documents that can be downloaded from www.iapws.org at no charge; consider reviewing the following at your earliest convenience:

- "Procedures for the measurement of carryover of boiler water and steam," to help prevent steam turbine damage.
- "Instrumentation for monitoring and control of cycle chemistry for the steam-water circuits of fossil-fired and combined-cycle power plants" provides guidance on the minimum level of key instrumentation required for managing water chemistry.
- "Volatile treatments for the steam-water circuits of fossil and combined-cycle/HRSG power plants" includes the basis for AVT and OT for all plants. The key recommendation: Only use oxidizing treatments in combined-cycle/HRSG plants.
- "Phosphate and NaOH treatments for the steam-water circuits of fossil and combined-cycle/HRSG power plants" includes the basis for selecting the optimum boiler/HRSG evaporator water treatment for all drum plants.
- "Steam purity for turbine operation" covers a wide range of failure mechanisms identified with steam turbines.
- "Corrosion product sampling and analysis" covers the optimum procedures for iron and copper sampling and analysis.

The foregoing documents represent the consensus opinions of the world's top chemists. National organizations from 21 countries provide the foundation for IAPWS, which makes its standards on cycle chemistry for fossil-fired steam and combined-cycle plants available to all at no cost.

IAPWS, founded in 1929, does much more than develop cycle chemistry standards. It also is the developer of IF-97, which forms the basis for every steam table in the world. Plus, the organization is responsible for all the formulations of water, steam, heavy water, ice, and seawater, as well as all the thermophysical properties of water and steam (density, viscosity, etc).

Dooley also is a member of the ACC Users Group steering committee. Learn more about this organization at www.acc-usersgroup.org.

CCUG recognizes four engineers for their contributions to the industry

The Combined Cycle Users Group recognized four power-industry professionals—Clyde V Maughan, Patrick C Myers, Peter So, and William Wimperis—with its 2013 Individual Achievement Award at the organization's annual meeting, held last September in Phoenix.

Individual Achievement recognition is earned by industry professionals who have demonstrated excellence throughout their careers in the design, construction, management, operation, and/or maintenance of generating facilities powered by gas turbines. The four outstanding individuals honored in 2013 were selected by the CCUG's Awards Committee, chaired by Andy Donaldson, VP projects for WorleyParsons. Nominations for the 2014 awards are now being accepted (see sidebar on p 34 of this issue).

The career accomplishments of the 2013 recipients are outlined below:

Clyde V Maughan, president, Maughan Engineering Consultants, Schenectady, NY, spent the first 36 years of his career after graduation from the Univ of Idaho (BSEE, 1950) at the General Electric Co as an engineer and manager in generator and turbine engineering design/service/development/manufacturing and a variety of other positions. Since retiring from GE, Maughan has been in private practice.

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

Plus, Maughan has served on several IEEE and IEC committees and working groups; managed a couple of major projects for EPRI; written or coauthored more than two-score major technical papers; published a handbook of more than 200 pages on generator repair and conducted nearly three dozen seminars (total of more than 1000 attendees) worldwide based on that work; and still had time to get an MS in Mechanical Engineering.

Most recently, the energetic 87 year old, has focused on disseminating to engineers worldwide the volumes of information he has compiled over the years. Much of this effort has been facilitated by the International Generator Technical Community™, an online forum that he helped to create. The IGTC library contains most of his technical documents. CCJ-online.com hosts the articles Maughan has published in the Combined Cycle Journal, as well as a series of webinars he conducted for CCJ ONscreen.

Patrick C Myers' career contributions to American Electric Power (AEP) and the Ceredo Generating Station that he manages are believed "immeasurable" by colleagues. Like many in the industry, Myers is a mechanical engineer who got his start at the General Electric Co as a field engineer. Later, he spent a couple of decades with the Columbia Gas Transmission Co before transitioning to AEP.

Following a series of relatively recent natural-gas explosions that caused deaths and considerable loss of property, Myers was appointed chair of an AEP internal team that designed and implemented venting and purging procedures for that fuel. This work earned Myers industry recognition and speaking assignments and his company a top Best Practices Award from the Combined Cycle Journal.

Myers has been the de facto leader of the 7EA Users Group steering committee for several years. This organization, which covers 7B-E models, as well as 7EAs, has benefitted considerably from his willingness to share knowledge and experience.

Peter So, project development manager for Calpine Corp, has been involved in the development of several leading-edge technologies in his more than two decades of work on gas turbines in simple- and combined-cycle service. Currently, So manages the development of new projects and major plant modifications for Calpine in the West—including those involving fast starting, fast loading, and reduced startup emissions.

Over the years he has been awarded patents in the following areas:

- Inlet bleed heat and power augmentation.
- A method for providing off-gas to a combustion system.
- GT engine controls for minimizing combustion dynamics and emissions.

The former General Electric Co DLN specialist and startup engineer previously served Calpine as a senior performance engineer and as manager of turbine controls. Among his many accomplishments, So led the software development of the first PSM LEC III retrofit on a 501D5. Plus, he was the lead controls engineer for the company's Humid Air Injection Project.

So also has been a long-term active participant on the steering committee for the 7F Users Group, contributing significantly to the organization's growth. A former co-chairman of the 7F Users, he currently serves as treasurer.

William Wimperis, who retired from Constellation Energy at the end of 2012 and recently joined Energy Services Inc, is one of the electric power industry's pioneers in the formation, organization, and development of user groups for sharing technical information on gas turbines. He served more than two decades as a member of the steering committees for the 7F, 501F, and 501G User Groups.

One of the founding members of the 7F Users Group, Wimperis was chairman of that organization for several years. His comprehensive notes from the early meetings are legendary. After 10 years on the 7F steering committee, Wimperis moved over to the 501F Users Group from 2000 to 2007 as his company's fleet diversified. Most recently, he served the 501G Users Group from 2008 to 2012, in lock-step with Constellation's purchase and completion of the 2 × 1 Hillabee Power Plant.

Wimperis managed several combined-cycle projects for Constellation during his 30 years with the company. His last position prior to retirement was director of project management. Responsibilities included overall technical management and leadership for all matters involving both engineering and development of new gas-fired generation.

Wood Group, Siemens update industry on joint venture

At a press conference conducted during Power-Gen International, Mark Dobler, CEO Wood Group GTS, Neil Sigmund, CEO TurboCare, and Chris Watson, CFO Wood Group GTS, updated the electric power industry on developments surrounding the

Dobler

recently announced joint venture between Wood Group GTS (51%) and Siemens' TurboCare business (49%).

Dobler, Sigmund, and Watson comprise the senior leadership team for the JV, which has yet to be named. Final approvals on the joint venture are expected in the first quarter of 2014. The business will have about 4500 employees worldwide and generate approximately $1 billion in annual revenue.

All of Wood Group's maintenance and power solutions businesses—except for its Rolls Wood Group, TransCanada Turbines, and Sulzer Wood JVs—are incorporated in the new entity along with TurboCare's aftermarket gas turbine, steam turbine, and generator design, repair, and manufacturing services.

Dobler described the new business this way: "The JV will bring together Wood Group's capabilities in the areas of asset operations, maintenance, risk management, and life-cycle optimization, with the aftermarket design, repair, and manufacturing capabilities of TurboCare to deliver greater flexibility, greater market reach, and an expanded footprint to service customers. The JV will be a significant integrated rotating-equipment service provider to the global power generation, oil and gas, and industrial sectors."

How the joint venture will benefit powerplant owner/operators is evident in the details presented below for each of the new entity's four primary business activities:

- **OEM.** The JV will be the OEM provider of parts, components, and associated overhaul and repair services for the generally more mature Fiat and Westinghouse (up to W501D4) turbines, and through Wood Group Pratt & Whitney, the P&W FT4 and GG4 products.
- **Authorized service provider to OEMs.** The JV will be an authorized provider of certain maintenance, supply-chain, and construction services to OEMs—including Siemens—for gas turbines, steam turbines, generators, and other rotating equipment.
- **Independent aftermarket service provider.** The JV will provide a broad independent aftermarket capability for gas turbines, steam turbines, and generators across a range of OEM equipment—including GE and Solar Turbines. This capability will include parts, components, and associated overhaul and repair services.
- **O&M and EPC service provider.** The new joint venture will provide O&M and EPC services for powerplants in cogeneration, combined cycle, and simple-cycle gas-turbine configurations.

Preservation program protects plant equipment during lay-ups

Inactive powerplant equipment can suffer rapid and oftentimes irreversible damage when left unprotected and exposed to the natural environment. Such exposure can occur before the plant has been completed (Fig 1), as well as after commissioning.

Prior to commercial operation, preservation procedures should be implemented and sustained from

1. Construction was stopped on several plants in the early 2000s because of changing economics. In some cases, equipment was not protected well from the elements the time equipment is manufactured until the plant for which it is intended is declared operational. During this period, warranties, insurance, and other considerations typically dictate that the OEM's and EPC contractor's procedures be followed.

Recall that construction on several combined cycles was halted in the early 2000s when the gas-turbine ordering boom went bust and equipment was put in storage, both indoors and outdoors, (Fig 2) as well as in partially completed plants. Following proper lay-up, equipment monitoring programs were put in place under the watchful eyes of preservation professionals to assure degradation mechanisms were being suppressed as intended. A great deal that was learned about equipment preservation during the bust—at plants such as NV Energy's Lenzie, Constellation Energy's Hillabee, Associated Electric Co-op Inc's Dell, and Copel and Petrobras' Araucaria—is of value for post-commissioning lay-ups. Use the search function at www.ccj-online.com to dig deeper.

After COD, the owner generally controls decision-making regarding preservation procedures—except possibly in cases where the maintenance of major equipment is governed by long-term service agreements. A big difference between preservation activities before and after commercial operation is that for the former, procedures are specific to individual pieces of equipment; for the latter, a more holistic approach is likely.

Example: One plan for the steam side of the heat-recovery steam generator (HRSG) also may cover HP and reheat steam piping and valves, and the steam turbine.

There are many reasons a plant might be laid up for anywhere from a month to several months—possibly longer. A typical retrofit project—even a major inspection—might require an outage of from four to six weeks; a good snow-pack might keep fossil-fired plants out of service for an entire spring to maximize hydro generation; legal issues could keep a unit from operating for years after completion.

An effective preservation program requires careful planning and diligent management. The fundamentals of these activities recently were compiled into a guidelines document by the engineers and scientists at European Technology Development Ltd, "Preservation Guidelines for CCGT and Conventional Power Plants during Short- and Long-Term Shutdowns," prepared by ETD's W Moore, J Ford, T Callagy, and Dr D G Robertson. The guidelines for both wet and dry preservation are based on the practical experiences of industry experts at power producers in both North America and Europe. Write Eur Ing David Slater (dslater@etd-consulting.com) for more information on contents and price of the 69-page ETD Report 1274-gsp-188.

In a telephone interview with the editors, ETD's Dr Ahmed Shibli said the major issue with long periods of inactivity is prevention of corrosion and its associated damage, which would adversely impact the plant's reliability during re-commissioning and subsequent service. He said ETD found information available on powerplant lay-up procedures fragmented, dividing the issues between chemistry and engineering considerations. Some information also was subjective, often linked to the use of a company's products. The objective of the EDT guidelines, Shibli continued, is to provide a broad view of the options together with the pros and cons.

The guidelines cover storage procedures to accommodate the type of plant, its history, outage time, locally available facilities, materials of construction, etc. Most plant shutdowns are planned, the metallurgist said,

2. Proper storage both indoors (left) and outdoors (right) requires rigorous procedures to protect equipment

giving advanced notice that lay-up procedures will be required. However, there are generating facilities—combined cycles in particular—that need procedures ready for immediate application to accommodate the vagaries of the markets they serve.

Shibli stressed that owner/operators consider the *entire plant* when developing their lay-up procedures, not just the major equipment. Here's a checklist of components/systems, among others, he recommended they include: HRSG water and gas sides, lube oil, steam turbine, condenser, generators, condensate/feedwater, water treatment plant, cooling water, transformers, switchgear, etc.

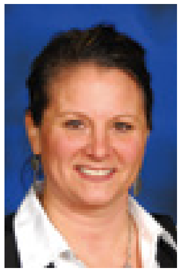
A few of the takeaways from report follow:

- Lay-up procedures depend to a large degree on the materials specified for plant equipment and systems. Example: If austenitic steels are present, then there will be a preference for all-volatile storage solutions (ammonia, for example) and chlorides should be limited to 0.3 ppm to minimize the risk of stress corrosion attack.
Take care, Shibli said, to exclude solid alkalis, such as tri-sodium phosphate. The preferred storage method for plants containing copper alloys (condenser tubes, for example) is dry storage. If wet storage

3. Pitting and rusting in a boiler steam drum after a hydraulic test and no preservation treatment

4. Breakdown of the passive oxide layer in an HP steam line that stood for six months without preservation treatment

is unavoidable, bear in mind that high-pH ammonia-based procedures are not suitable—particularly under aerated conditions.
- The length of the lay-up period and the local environment significantly influence lay-up procedures. In general, wet lay-up is preferred for short shutdowns, dry lay-up for longer periods.
However, today's world is not so straight forward. Grid demands may make it impossible to determine just how long a lay-up will be at the planning stage; sometimes generating units are recalled to service with little notice.
Alternatively, if a wet lay-up is prolonged, it is necessary to have a circulation system installed to keep



water chemistry balanced throughout the HRSG and to assist in the mixing of any additional chemicals that may be required for the duration of the outage.

- Whether storage is wet or dry, routine checks are required to assure that the preservation plan is working correctly and that the optimal lay-up environment is being maintained (Fig 3).
  In general, equipment should be checked daily until the storage team is satisfied that the preservation program is stable and reliable. At that point, the frequency of monitoring typically can be relaxed to twice weekly.
- Some plant modifications likely will be required to implement either wet or dry lay-up. The guidelines summarize available storage procedures and provide an overview of required modifications for each. If the planned storage is expected to be of limited duration, temporary solutions may be satisfactory. But if you expect to put a unit in storage regularly (such as each spring to maximize hydro production), well-designed permanent facilities should be considered. A series of logic diagrams is provided in the guidelines to assist in the development of suitable storage procedures.

Global forum for gas turbines launched

A global technical forum for gas-turbine owner/operators and others with interest in this equipment has been established at www.powerplanttechnicalforum.org. This site also serves the highly successful Generator Technical Forum, and the Steam Turbine Forum announced at Power-Gen in November 2013. Most subscribers to CCJ ONsite and the print CCJ are familiar with the generator forum, now completing its fourth year of service to the industry. It has 2000 registered members from nearly 90 countries.

The Gas Turbine Forum is an online network connecting industry professionals worldwide. Like the Generator and Steam Turbine Forums, it is managed and conducted by industry volunteers with financial support from National Electric Coil. The forum's mission is to facilitate access by electric-power professionals to technical information on gas turbines.

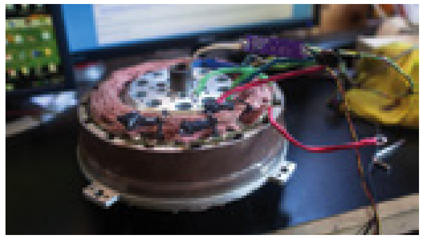
Here's a list of the moderators for the Gas Turbine Forum, their company affiliations, and the forum subject matter that is their responsibility:

Forum Master: Justin Voss, AES.
Overhaul Best Practices: Jeff Fassett, PE, IEM Energy Consultants Inc.
Component Life Cycle Management: Dr Maxine Watson, Quest Integrity Group (NZ).
Maintenance Issues: Sal Paolucci, GT Accent Services.
Control Systems and Monitoring: Joseph Clappis, MD&A.
Efficiency: Rodger Anderson, PE, DRS Power Technology Inc.
Governing Protection and Control: John Downing, Turbine Controls & Excitation Group Inc.
Auxiliary Systems Reliability: Scott Cavendish, PE, Independent Turbine Consulting.
Aeroderivatives: Bill Torrance, C Eng, Independent Consultant (UK).
High Impact/Low Probability: Sep van der Linden, Brulin Associates.

Important for users to understand is that this new forum does not replace any forums already existing within the gas-turbine community, it complements them by focusing on engine technology as it is applied to all types of gas turbines the world over. There are many valuable forums addressing specific engine models, several of which are hosted by users groups on their websites—such as the Western Turbine Users Inc, 501D5-D5A Users, 7F Users Group, and CTOTF™. Other forums—such as those for the 7EA, 501F, and 501G Users Groups—are hosted at http://www.users-groups.com.

5. Daedalus, the Univ of Minnesota's entry in the 2013 World Solar Challenge, conducted in Australia two months ago, finished fourth in class. The name in Latin means "skilled craftsman" (left)

6. Wheels, designed by engineering students, were made by Cutsforth's manufacturing team (below)



Bridging the gap between raw talent and experience

Power-industry executives are often heard lamenting about the ageing industry workforce and the difficulty they have finding new and capable employees for their businesses. Two thoughts:

- Turnover is not always a bad thing. It creates space for the innovative thinking needed to drive the organization forward.
- The responsibility for developing the talent needed to advance the business is yours, not a university's, the military's, or any other organization's.

Many generating companies, and manufacturers and services firms associated with the electric power industry, provide financial support for training programs, internships, and university courses to help develop future talent. That's the "right thing" to do and commendable. Cutsforth Inc took its involvement in the development of future engineers to the next level by working directly with students from the Univ of Minnesota who needed help manufacturing custom wheels for their entry, Daedalus, in the 2013 World Solar Challenge (Fig 5).

The wheels for the ultra-light solar vehicle were designed by the engineering students; Cutsforth's manufacturing team CNC-machined them from solid blocks of aluminum to a tolerance under 0.003 in., thereby eliminating the need to balance the wheels after the tires were mounted. In an innovative approach to space and weight savings, portions of the electric motors were designed to be housed inside the wheels themselves. Cutsforth's manufacturing team helped to make this goal a reality (Fig 6). More than 80 hours of programming and CNC machining time went into wheel production. All labor and materials needed to make the four wheels were donated by Cutsforth.

The World Solar Challenge, held every two years in Australia, runs north to south from Darwin to Adelaide, a distance of nearly 1900 miles. The Univ of Minnesota team finished the grueling race, placing fourth in the Cruiser Class.

Summing up Cutsforth's involvement in the innovative project, GM Benjamin Warums said, "The electric power industry is where we work and this project allowed us to help the students working toward the advancement of alternative forms of energy. We were honored to be approached by the Univ of Minnesota and take great pride in our manufacturing team's ability to hold tight tolerances. Helping future innovators was a natural fit for Cutsforth. We congratulate the university's solar car team for its creative work and for finishing the race."

Peaker produces 180 MW in 12 minutes, holds emissions within California limits

Over the last couple of years, Siemens Energy Inc and Mitsubishi Power Systems Americas Inc have strengthened their positions among the technology leaders for frame gas turbines. Siemens' successes include H-class and fast-start/fast-ramp combined cycles, Mitsubishi's include 501GAC-powered combined cycles and its giant J-class gas turbine.

Power producers evidently have been impressed, judging from the two-to-one advantage the two companies held over perennial market leader GE Energy in sales of frames for US electric generation in 2012 (capacity basis).

More recently, Siemens and Mitsubishi collaborated to assure the success of NRG Energy Inc's four-unit, nominal 720-MW Marsh Landing Generating Station, a simple-cycle facility in Antioch, Calif, about 40 miles northeast of San Francisco. It began commercial operation May 1, 2013. Siemens supplied four SGT6-5000F (501FD4) gas turbines equipped with ULN (ultra low NO_x) combustion systems, four SGen-1000A generators, the SPPA-T3000 control system, and balance-of-plant equipment, as well as technical support for installation and commissioning.

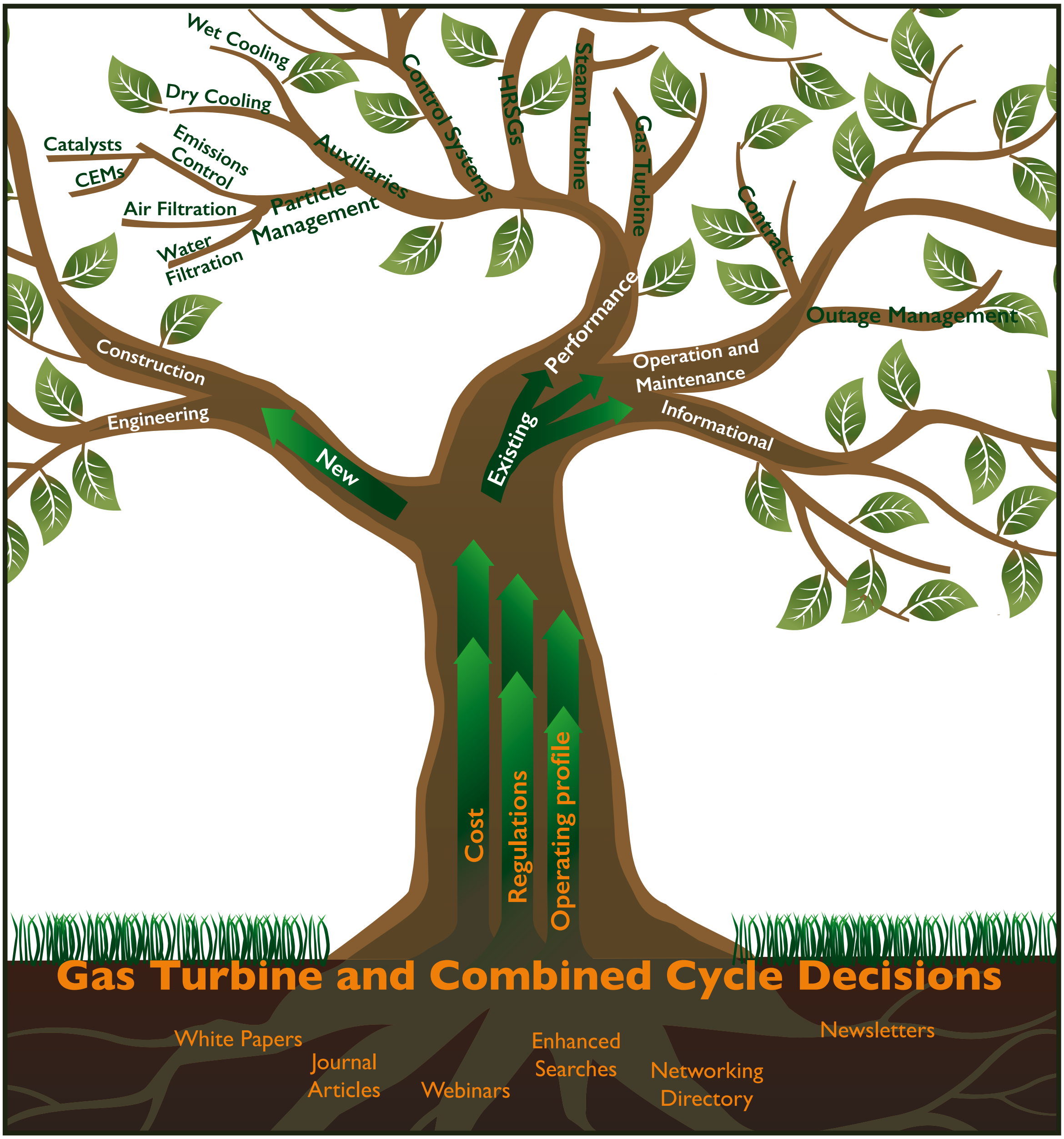
Mitsubishi provided a leading-edge dilution SCR system for each engine to reduce the 9 ppm NO_x/4 ppm CO in turbine exhaust to 2.5 ppm/2 ppm out the stack. Ammonia slip is restricted to 10 ppm. Cormetech Inc and Johnson Matthey supplied state-of-the-art SCR and CO catalyst formulations, respectively, to guarantee emissions conformance.

Siemens partnered with NRG to implement an integrated control technology that allows the plant to maintain low emissions while navigating fast, intermittent load ramps. All four units demonstrated ramp rates of up to 32 MW/min, reaching base load in 12 minutes while holding emissions within permit limits. Siemens refers to this as its Clean-Ramp™ technology.

Mitsubishi's scope included CFD and physical flow modeling to guide the design and supply of all equipment from the gas-turbine expansion joint to the stack, including the following:

- SCR catalyst modules and drop-in CO catalyst panels.
- Inlet and outlet transition ducts and all expansion joints.
- A 2 × 100% tempering-air/purge-air skid complete with accessories and interconnecting ductwork from the fans, including tempering-air distribution devices within the SCR system casing.
- Ammonia forwarding skid, vaporization skid, and injection grid with balancing manifold.

Accelerate the decision-making process with:



If you are an owner, operator you can register free of charge at:
http://www.mcilvainecompany.com/GTOReg.htm

If you are a supplier and want to participate learn more at:
http://www.mcilvainecompany.com/GasTurbineMarket.htm

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- PLC-based SCR emissions controls and control logic interface to the DCS.
- Exhaust stack with advanced silencing systems.

Marsh Landing, located on a 27-acre brownfield site in a challenging seismic zone, complies with some of the nation's most strict limits for NO_x, CO, VOCs, and particulates. The facility sits adjacent to the Contra Costa Power Plant, a nominal 680-MW station with two 1960s gas/oil-fired steam units; it was retired the day the new facility began commercial operation.

Marsh Landing relies on water and wastewater infrastructure owned by the city of Antioch and the Delta Diablo Sanitation District. Its planned water consumption of 50 acre-ft/yr is a 99.99% decrease from what Contra Costa required. The old steam plant had a once-through cooling system.

NRG has a 10-yr power purchase agreement with PG&E for the entire output of the facility. Electricity is delivered to the utility's existing switchyard adjacent to Marsh Landing via 230-kV lines. Natural gas is supplied via a new pipeline that connects to PG&E's interstate gas transmission line about ¼ mile from the plant.

Hill to succeed Fusco as CEO; Calpine has a good 3Q

Calpine Corp's board of directors has selected Thad Hill, the company's president/COO, to succeed Jack Fusco as CEO when the latter assumes the role of executive chairman of the board in May 2014. The change is part of a planned leadership transition. Hill joined Calpine in September 2008 from NRG Texas where he served as president in 2007-2008.

Calpine is said to generate more electricity than any other independent power producer in America. Its fleet of 93 powerplants totals 28 GW of nameplate capacity in operation or under construction. The company reported an increase in third-quarter operating revenue of 18.3%, year over year; net income increased by more than 11%.

Beyond the financials, Calpine plant and central engineering personnel contributed to the company's success in the third quarter by:

- Producing more than 30 million MWh.
- Achieving a record-low year-to-date fleet-wide forced outage factor of 1.4%.
- Delivering record-high year-to-date fleet-wide starting reliability of 98.8%.
- Reducing year-to-date plant operating expenses by about 7%.
- Maintaining top-quartile safety metrics: 0.85 total recordable incident rate year-to-date.

Significant plant developments in the third quarter include the following:

- Russell City Energy Center commenced commercial operation in August. The facility, which produces 429 MW of base-load and 464 MW of peak capacity, is under contract to deliver its full output to PG&E for 10 years.
- Los Esteros Critical Energy Facility was recommissioned as a combined-cycle plant and resumed delivering power to the grid in August. The facility began life in 2003 as a four-unit LM6000 peaking facility with a rated output of 188 MW. Conversion to combined cycle increased generating capability to 309 MW while increasing efficiency and environmental performance.
- Osprey Energy Center achieved 100% starting reliability and 0% forced-outage factor.
- Pastoria Energy Center achieved 92% capacity factor and 99.8% availability.

Products/services

Camfil Farr Power Systems' lab-on-wheels (the Camlab) allows gas-turbine users to evaluate, in real time under the actual operating conditions at their sites, alternative filtration solutions simultaneously with no risk to operating equipment.

Clark-Reliance Corp announces Safe View™, a shield for use on armored-glass liquid-level gauges to protect operators from high-pressure leaks, a rare but potentially dangerous situation. The shields are easily retrofitted on C-R Jerguson® gauges as well as on similar gauges made by others.

Company news

Wood Group GTS is awarded a six-year contract to provide maintenance services for a GE 7EA at a manufacturing facility in Texas. This includes all major maintenance services—including parts, repairs, field services, and the installation of M&D technology for predictive performance management. . . .A southeastern power producer selects the company to supply ECOMAX™ combustion tuning and dynamics monitoring systems for a fleet of 7FA gas turbines.

International Generator Technical Community (http://www.generatortechnicalforum.org) announced its highly successful discussion forum for generator professionals now has 2000 members in 88 countries. Also, that it has expanded into steam turbines. Bios for the steam-turbine discussion moderators, volunteers all, and their areas of expertise are posted on the website.

Mistras Group reported its acquisition of Carmgen Engineering Inc, a professional engineering consulting and technical training services provider, capable of helping clients shorten the duration of their outages and extend the interval between shutdowns without compromising safety and reliability.

Metso and Turbine Services Ltd agree to use the Metso DNA turbine automation system on all future projects where TSL supplies turbine components and other materials.

NRG Energy Inc enters into an agree-

7. Magnolia project team members attending the reunion were Glenn Turner, Ron Maxwell, Bill Carnahan, Scott Mellon, Frank Messineo, Himanshu Pandey, Ron Davis, Stephen Cole, Fred Fletcher, Ira Joffee, Bill Hutchings, Matt Gonzales, Gary Rose, and Bruce Blowey (l to r). Camera shy: Victor Luke and Tom Roth. The 16 team members represent 462 years of power-industry experience

8. Maryland Heights REC technicians Frank Dains, Dennis Blasé, and Stanley Oberlohr display the 2013 Pacesetter Plant Award in the plant's control room

ment to acquire Edison Mission Energy's 8-GW portfolio of powerplants.

Portersville Valve Co LLC and PRD Technologies LLC, both suppliers of pressure-relief systems for powerplants, agree to merge.

Hamon Deltak Inc opens an office in Denver.

People

NAES Corp opens a new facility for its Industrial Services Div in Sulphur, La. . . .hires Tom French, most recently self-employed, as VP Quality Assurance. . . .hires Kevin Taylor, former president of MasTec Inc, as senior VP of engineering and construction.

Victory Energy hires Vijay Patel to help lead the company's business expansion efforts in the power and utility markets.

ProEnergy announces the addition of Charlie Athanasia as COO and Craig Kingsley as VP turbine services. Athanasia was VP of Alstom's thermal services business in North America; Kingsley has more than 20 years of operations and general management experience in the heavy industrial turbine market with Dresser-Rand, TGM, Sulzer, and GE.

Plant news

Burbank Water & Power, Magnolia Power Plant. Bill Hutchings, a long-term CCJ supporter, reports that the project team for the award-winning 1 × 1 Magnolia combined cycle recently celebrated the 10th anniversary of the project's groundbreaking (Fig 7). Located in downtown Burbank, the unit incorporates the world's first GE HEAT™ (high-efficiency advanced technology) steam turbine, operates solely on reclaimed water, and includes an advanced zero-liquid-discharge system.

Ameren Missouri's Maryland Heights Renewable Energy Center receives CCJ's 2013 Pacesetter Plant Award for advancing the state-of-the-art for the electric power industry in the use of renewable fuels for carbon management, the combustion of challenging fuels in advanced gas turbines, and the integration of automation, monitoring, remote capability, digital intelligence within PLC architecture (Fig 8).

Patriot CCPP, Clinton Twp, Pa, orders two H-class gas turbines from Siemens Energy Inc. The 829-MW facility is expected to begin operation in 2016. These are the 26th and 27th H-class GTs sold by Siemens worldwide.

Lakewood Cogeneration Plant, owned by Essential Power™, commissions a Symphony Plus control upgrade supplied by ABB.

COMBINED CYCLE Journal 3Q/2013

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