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COMBINED CYCLE Journal

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2011 meetings for GT Users

Early 2011, 501D5-D5A Users, Mid-Year Meeting. Details as they become available at www.501D5-D5Ausers.org.
Contact: Gabe Fleck, chairman, gfleck@aeci.org.

February 14-18, 501F Users Group, Annual Meeting, San Diego, Paradise Point Resort & Spa. Chairman: Russ Snyder, russ.snyder@cleco.com.
Contact: Caren Genovese, meeting coordinator, carengenovese@charter.net.

February 14-18, 501G Users, Annual Meeting, San Diego, Paradise Point 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.

March 20-23, Western Turbine Users Inc, Renaissance Palm Springs Hotel/Palm Springs Convention Center. Chairman: Jon Kimble, jkimble@wellhead.com. Visit www.wtui.com for more information.

April 4-6, HRSG User's Group, 19th Annual Conference & Exposition, Manchester Grand Hyatt San Diego. Contact: Robert Swanekamp, executive director, info@hrsgusers.org.

April 10-14, CTOTF—Combustion Turbine Operations Task Force, Spring Turbine Forum & Trade Show, West Palm Beach, Fla, PGA National.
Contact: Wickey Elmo, group and conference coordinator, info@ctotf.com.

May 9-13, 7F Users Group, Conference & Vendor Fair (May 11), Westin Galleria Houston. Contact: Sheila Vashi, meeting and exhibition coordinator, sheila@vision-makers.com. Visit http://ge7fa.users-groups.com for details as they are made available.

June timeframe, 501D5/D5A Users, Annual Conference & Expo. Details as they become available at www.501D5-D5Ausers.org.
Contact: Gabe Fleck, chairman, gfleck@aeci.org.

June timeframe, Southwest Chemistry Workshop, 20th Anniversary Meeting. Details as they become available at www.combinedcyclejournal.com/SouthwestChemistry.html.

June 6-9, Frame 6 Users Group, Annual Conference & Vendor Fair, Scottsdale, Ariz, Doubletree Paradise Valley. Details as they become available at www.Frame6UsersGroup.org.
Contact: Wickey Elmo, conference coordinator, wickelmo@carolina.rr.com.

June timeframe, V Users Group, Annual Conference. Dates and venue not yet available.
Contacts: Bob Pasley, chairman, bpasley@aeci.org;
Dawn McCarter, conference coordinator, dawn.mccarter@siemens.com.

September 11-15, CTOTF—Combustion Turbine Operations Task Force, Fall Turbine Forum & Trade Show, Scottsdale, Ariz, Doubletree Paradise Valley.
Contact: Wickey Elmo, group and conference coordinator, info@ctotf.com.

Now serving the entire Western Hemisphere

Journal boosts circulation to reach owner/operators responsible for 460,000 MW of gas-turbine-based generation in North, Central, and South America, and the Caribbean, and for the installation of another 135,000 MW by the end of 2015

Welcome new subscribers from Central and South America and the Caribbean. You no longer have to read the COMBINED CYCLE Journal online. Beginning with this issue, hard copies are available to owner/operators of gas-turbine-based generating facilities throughout the Western Hemisphere. Until now the quarterly journal was mailed to qualified recipients only in North America (US, Canada, and Mexico).

Please tell your colleagues on the deck plates and those in the company's central engineering offices that they too can receive the CCJ by accessing the electronic subscription form at www.combinedcyclejournal.com/subscribeonline.html and providing the information requested. The whole process should take only two or three minutes.

Requirements for a complimentary subscription: Employment by an owner/operator and responsibility for design, engineering, construction, operation, and/or maintenance of gas turbines (GTs) larger than 5 MW.

It's sometimes difficult for industry people to believe that the first GT for commercial power generation in the Western Hemisphere was installed only 60 years ago at Oklahoma Gas & Electric Co's Belle Isle Station. That 3.5-MW engine, developed by General Electric Co, was used to both generate electricity and preheat feedwater for a conventional 35-MW steam/electric unit.

It really wasn't until the early 1970s that gas turbines gained acceptance by *some* utilities as a viable method for producing power during periods of peak demand. The overwhelming majority of engines installed then were rated less than 25 MW; 60 MW was about the top size.

Fast forward. Today GTs produce power in fast-start simple-cycle facilities, cogeneration plants, and combined cycles. The largest commercial units develop well over 300 MW. Duty cycles include standby, peaking, intermediate, and base load. Simply put, GTs are the most versatile of the big-power options available to utilities, merchant power producers, and industry—as well as the most efficient.

So popular are these machines that gas-turbine-based plants now account for 32% of the total generating capability in the Western Hemisphere. More specifically, the CCJ now reaches personnel responsible for the operation and maintenance of 460,000 MW of installed generation, plus engineers and managers involved in the design and construction of an additional 135,000 MW scheduled for commercial service by the end of 2015. Both numbers include the capability of steam turbines in combined-cycle plants.

Central and South America and the Caribbean together have 49,000 MW of GT-based capacity in operation and another 32,700 under construction or planned. Half of the capacity in service was installed in the last 10 years and many plants have engine models popular in the US. For example, there are 78 LM

Mexico, Altamira III and IV. Each a gas-only, 518-MW, 2 × 1, GE 7FA-powered combined cycle

Chile, San Isidro 1. A dual-fuel, 379-MW, 1 x 1 combined cycle powered by a Mitsubishi 501F

(General Electric aeros), including 51 LM6000s; more than 70 GE frames in operation or planned; 38 W501 machines in service, including 17 W501Fs.

What might be most surprising to someone spending most of his or her time working in the US is that there are 75 Alstom/ABB engines in operation, being installed, or planned in the region—including 29 GT11s. Two other facts of interest: (1) 54 peaking units rated more than 100 MW are under construction or planned; (2) 81 engines rated 60 MW or more are dual-fuel capable.

If you want to learn more about your company's opportunities for new business in the Western Hemisphere, or anywhere else in the world, consider ordering the Combined Cycle and Gas Turbine Data Set from UDI, a unit of Platts (www.udidata.com). The authoritative database gives unit-level data critical to deciding which assets to contact—such as, unit rating, COD, type of facility, fuels, GT model, HRSG manufacturer, steam conditions, type of NO_x control, etc.

The photos show several generating plants south of the US border which are operated and maintained by the CCJ's new subscribers. They were provided by the folks at Indust-Cards. Access www.industcards.com to get information on powerplants of all types in every region of the world. **CCJ**


Power Generation Co of Trinidad & Tobago

Trinidad & Tobago, Point Lisas. Site has the following gas-fired engines: Two GE Frame 5N, four Siemens W501D, three Alstom GT11, and two Siemens W501D5A


Suez

Peru, Chilca Uno. Two gas-fired, 174-MW V84.3A gas turbines

Class *of* 2009/2010

Cornell Combined Heat and Power Plant

Ithaca, NY

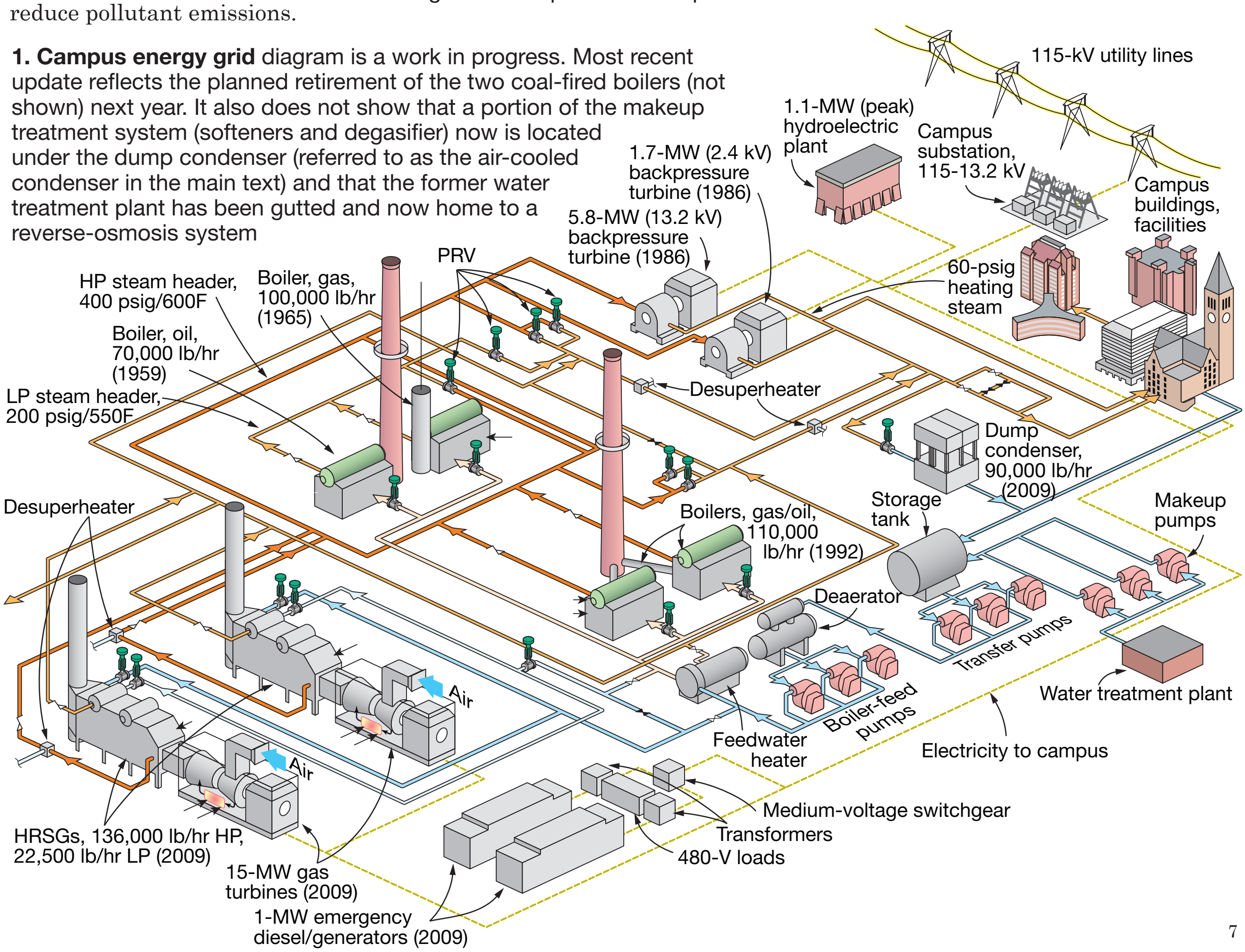
Cornell University

Transforming a steam plant into a full-service utility

Cornell University has a respected engineering school and many people on campus—faculty and students alike—know a thing or two about thermodynamics, plus there are others who are very knowledgeable in the environmental sciences. So it was only a matter of time before the Ithaca campus's conventional steam plant, which burned coal as its primary fuel, would undergo major renovation to improve efficiency and reduce pollutant emissions.

Monument was created from rock unearthed during construction from the glacial till deposited at the plant site

The commercial operation last December 18 of two 15-MW gas turbines (GTs) and their accompanying heat-recovery steam generators (HRSGs) was the latest step taken by the university to modernize its energy infrastructure. For Cornell, the process of continual improvement began about 25 years ago. At that time, the central plant, constructed in 1922, was steam-only; all electricity was purchased from the local utility.



1. Campus energy grid diagram is a work in progress. Most recent update reflects the planned retirement of the two coal-fired boilers (not shown) next year. It also does not show that a portion of the makeup treatment system (softeners and degasifier) now is located under the dump condenser (referred to as the air-cooled condenser in the main text) and that the former water treatment plant has been gutted and now home to a reverse-osmosis system

Recent history

In 1981, two run-of-river hydroelectric turbines were installed—one rated 800 kW, the other a nominal 1100 kW (Fig 1). Both produced power at 2.4 kV. Peak capacity from the facility was 1100 kW, stream flow permitting.

A 90,000-lb/hr (400 psig/600F) spreader-stoker-fired boiler also was added in 1981. The new steam generator and an existing 175,000-lb/hr, overfeed-stoker-fired boiler together burned about 65,000 tons of low-sulfur eastern bituminous coal annually and produced about 90% of the steam required for campus heating.

Five years later, with the nation embracing cogeneration, two back-pressure steam turbines were installed—one rated 5778 kW, one 1692 kW. Both noncondensing units operate as campus steam demand permits. The generator coupled to the large turbine feeds the 13.2-kV bus, the other supplies the 2.4-kV bus serving the campus area with the oldest buildings.

Around the same time, the university decided to upgrade the campus electric distribution system to address power-quality issues, and reduce its electric bill as well, by installing a substation to receive utility power at 115 kV. Up until 1988, all electricity not produced onsite—roughly 85% of annual consumption—was delivered by the local utility, New York State Electric & Gas Corp (NYSEG), at 13.2 kV.

The so-called Maple Avenue Substation's two 100%-duty transformers, each rated 30 MVA, were connected to two independent 115-kV lines, thereby providing the higher level of electric-system reliability needed to support an expanding campus and research activities. This arrangement allowed one transformer to serve the endowed campus, the other the state campus, to facilitate operations and billing (Sidebar 1).

The electrical design team from O'Brien and Gere, Syracuse, provided the capability for one transformer to supply the entire Ithaca campus, if necessary. O'Connell Electric Co, Victor, NY, was the general contractor on the substation project. Payback on the investment was a nominal eight years.

Shortly after completing the electrical upgrade project, Cornell added two 110,000-lb/hr (nominal output at 400 psig/640F), D-type gas/oil-fired packaged boilers, allowing the university to "park" its older 200-psig (550F) packaged boilers in standby service (refer back to Fig 1). This1992 improvement, engineered by Gryphon International Engineering Services Inc, headquartered in St. Catherines, Ont, provided greater operating flexibility while reducing emissions and boosting the efficiency of steam production.

Peer

The next major project focused on reducing the amount of energy needed to produce the approximately 40-million ton-hours of chilled water required campus-wide in the late 1990s. At that time, Cornell Utilities operated and maintained four chilling facilities in Ithaca, one alongside the cogeneration plant (Sidebar 2).

The "free-cooling" energy management solution implemented in 2001 was made possible by the university's location. It is only a stone's throw from the southern end of Cayuga Lake, the longest (almost 40 miles) of New York's glacial Finger Lakes and the second largest in surface area (66 square miles). Average depth is 182 ft (435 ft at the deepest point); volume is 2.27 cubic miles.

What Cornell did, following substantial research and a lengthy permit process, was to pull 40F water from about 250 ft below the lake's surface and use it to extract heat from the campus closed cooling-water (CCW) system via plate heat exchangers located shoreside. Water is returned to the lake at about 55F with no adverse environmental impact.

CCW at about 45F is distributed campus-wide for space conditioning and process cooling. The centrifugal chilling plant/thermal storage tank located alongside the cogeneration plant was retained (the other three were deactivated) in case additional cooling is required on hot summer days as the campus expands. Management thinks it might be difficult to permit more "free" cooling from the lake. The so-called Lake Source Cooling Project reduced the energy required for cooling by 86%, including more than 20 million kWh annually.

Paradigm shift

Success in implementing large-scale energy-conservation and emissions-reduction solutions prepared the Cornell Utilities' staff for handling what was to become the biggest step yet in the organization's rich history: The conversion of a superannuated steam plant with some residual electric production into a bona fide "utility" capable of producing about three-quarters of the kilowatt-hours the university consumes annually, as well as all of its thermal (heating and cooling) needs (Sidebar 3).

Project manager for the Cornell Combined Heat and Power Project (its tongue-twister acronym shortened to CHP for this article) was Timothy S Peer, PE, recently named energy plant manager. Heart of the CHP system is two Titan 130 gas turbine/generators (Solar Turbines Inc, San Diego) and their accompanying HRSGs from Rentech Boiler Systems Inc, Abilene. However, there was much more to the overall project, including the following:

1. Cornell's mission

Cornell University, founded in 1865, is a privately endowed institution. Additionally, it is the federal land-grant institution of New York State and a partner, through the Contract Colleges, of the State University of New York (SUNY). In pursuing its mission of teaching, research, and outreach, Cornell provides facilities that serve tens of thousands of faculty and students. Its Ithaca campus alone supports more than 11,500 faculty and staff and about 20,000 students.

Roughly 40% of the main campus serves SUNY's statutory contract colleges; another 2-3% is dedicated to federal and private research facilities. The balance is the endowed segment of the institution.

2. Vital utilities

A key component of Cornell's Division of Facilities Services is Utilities and Energy Management, headed by Director James Adams. The five dozen or so full-time employees in Adams' group are responsible for operating and maintaining the central heating and cooling production and distribution facilities on the Ithaca campus, as well as the following systems: electric substation and distribution, potable water production and distribution, sanitary and storm sewer collection, and campus-wide energy management and building operations.

Referred to internally as Cornell Utilities, the group serves more than 150 buildings totaling about 14 million ft^2 of floor space.

3. The changing face of power

Cornell University's central steam plant, built in 1922, was expanded—and support facilities added—over the years to accommodate new boilers, backpressure steam turbine/generators, etc. When the first aerial in the sequence below (A) was snapped in 2003, the plant was home to two coal-fired boilers, four boilers capable of burning gas and/or oil, two steam turbines, and all the auxiliary systems and equipment required to operate the facility. The plant was capable of supplying all the thermal energy, and about 15% of the electricity, required by the university.

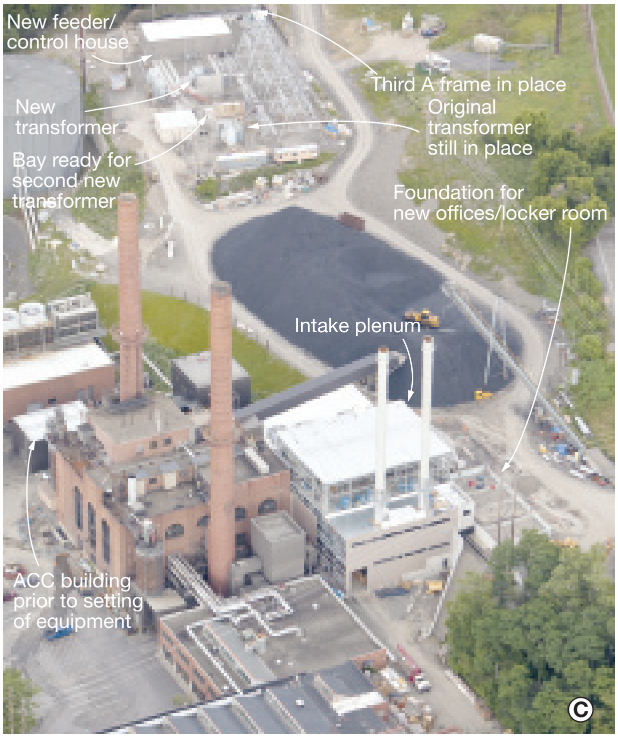
Five years later, the transformation from a steam plant to a utility was well underway. Photo B shows the access roads carved out around the coal pile and substation to allow equipment deliveries and provide parking for workers. A new coal conveyor had been installed to minimize fugitive dust emissions—this work done only a couple of years before the decision was made to decommission the stoker-fired boilers.

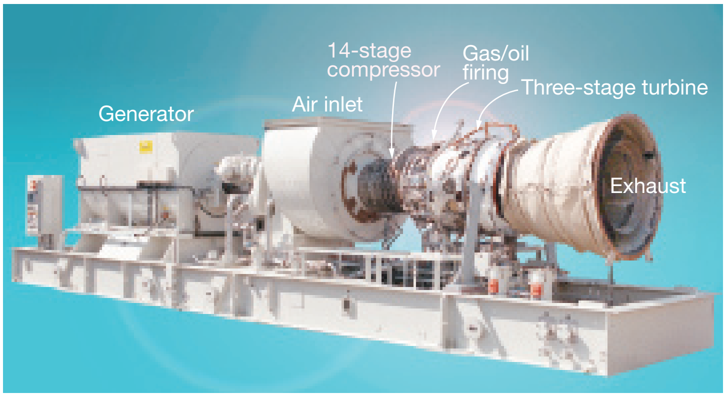
Note, too, that the gas turbines and heat-recovery steam generators were rough-set on a floor mat before the CHP building was constructed. Also, the resid tank in Photo A had been rehabilitated for distillate, and upgrade of the thermal storage tank was complete.

Photo C, taken in July 2009, reveals construction of the CHP building well underway, construction of the steam condenser building awaiting installation of the air-cooled condenser on its roof, work progressing on the campus substation, and new feeder/control house in place and installation of new switchgear under way.

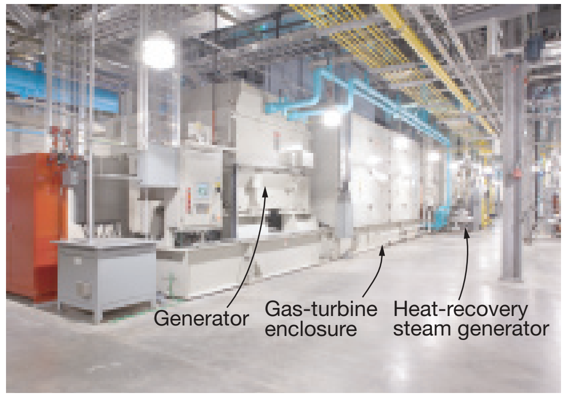
Photo D, taken last April, shows all major work complete: substation upgrade, CHP facility, ACC, etc, right down to the installation of solar thermal panels on the roof of the new staff offices to provide building heat and domestic hot water.

All photos in this sequence were taken by Ithaca-based Jon Reis Photography (www.jonreis.com). Reis also shot the photos for Figs 3, 5, 8, and 9 in the main article.

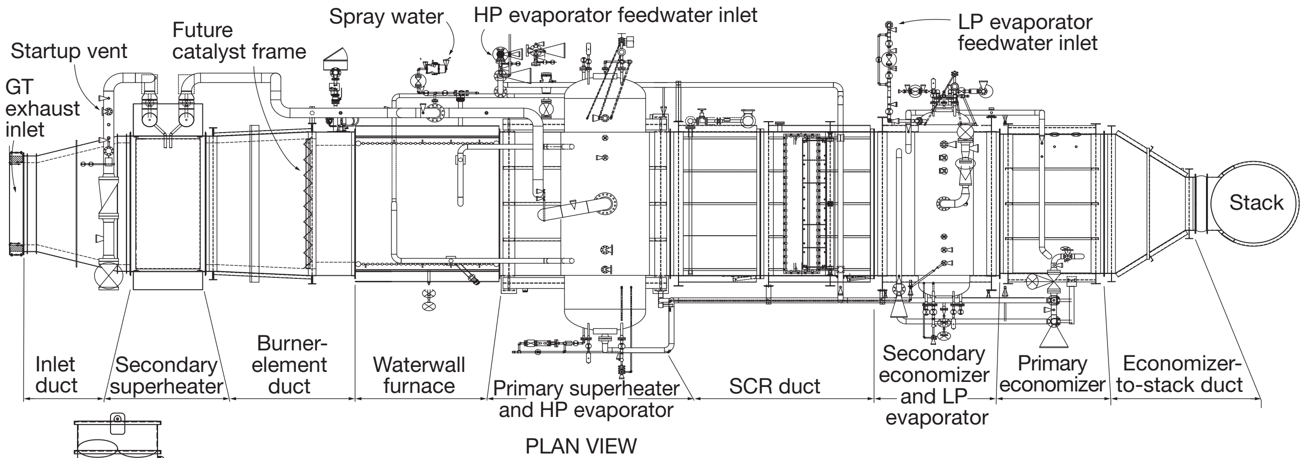


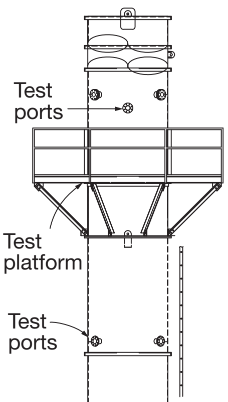


2. Titan 130, at 15 MW, is a relatively large gas turbine for a university powerplant (above)



3. GT/HRSG train looking back toward the boiler from the generator on the compressor end of the Titan 130 (left)

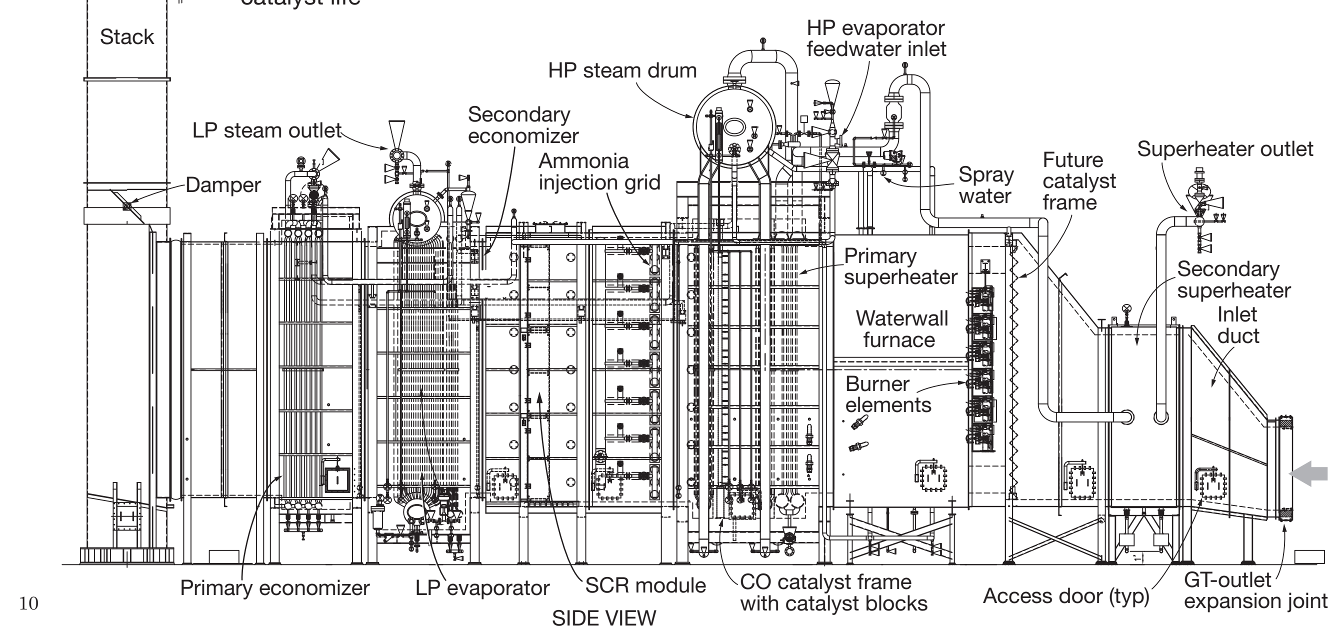




4. Dual-pressure HRSG, uncommon in this size range, reveals waterwall surface adjacent to the duct burner to reduce maintenance, and CO catalyst and SCR optimally located for top performance and long catalyst life

- A major addition to the old plant (18,000-ft^2 footprint) for the GTs, HRSGs, and their auxiliaries, plus new engineering and administrative offices, training room, and shower/locker-room facilities.
- Installation of a new natural-gas supply system.
- Installation or upgrade of auxiliary systems to support the CHP—including air-cooled condenser, fuel-oil storage, ammonia storage (SCR reagent), black-start diesel/generators, etc.
- Reconfiguration of the Maple Avenue Substation and upgrade of medium- and low-voltage switchgear serving the campus.
- Decommissioning of Cornell's coal-fired boilers and support infrastructure, which will happen next year.

The engineer of record for the CHP project was GIE Niagara Engi-



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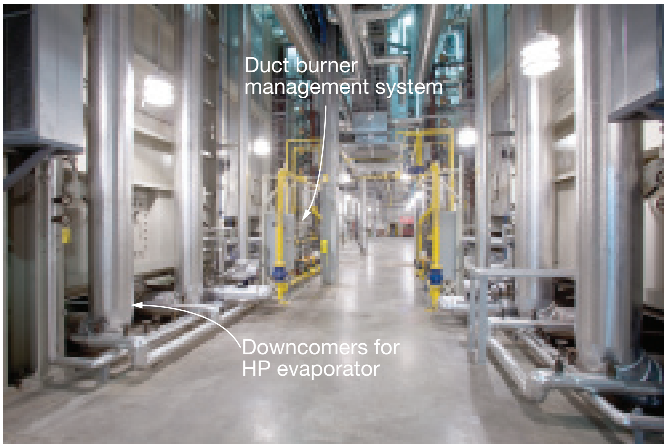


5. HRSGs are at the right and left looking down the CHP building toward the GTs

6. Duct-burner gas skid sits alongside the HRSG that it serves

neering Inc PC, the US affiliate of Gryphon International Engineering Services. Environmental permitting was done by ENSR International Corp, Westford, Mass; construction management by LeChase Construction Services, Rochester, NY.

The single-shaft Titan 130 has a 14-stage axial compressor operating at a 17.1:1 pressure ratio (Figs 2, 3). Output at the 59F/sea level design point is 15 MW; heat rate is 9695 Btu/kWh and engine efficiency measured at the generator terminals is 35.2%. Numbers assume no inlet, exhaust, and accessory losses, 60% relative humidity, and natural-gas fuel with a lower heating value of 940 Btu/scf.

Combustion chamber for the dual-fuel (natural gas and ultra-low-sulfur distillate) engine has 21 conventional fuel injectors. Transfer to oil from gas (and from gas to oil) can be done with the GT in operation. Operating permit restricts operation on oil to 2000 hours annually between the two machines.

The Titan 130's three-stage, axial-flow turbine drives its generator via an epicyclic gear train which reduces the 11,220-rpm turbine output to 1800 rpm. The wye-connected synchronous generator has a brushless exciter.

The machine's integrated lube-oil system includes turbine-driven, pre/post, and backup oil pumps, oil cooler, oil tank with heater, oil mist eliminator, and simplex filter. Chilled water for cooling GT inlet air, lube oil, and the generator is provided by the campus network.

Gas turbines came equipped with Solar's Turbotronic™ 4 PLC-based control system, which includes all circuitry, instrumentation, and software required for engine control, monitoring, and protection. The supervisory control system provided by controls integrator The Rovi-Sys Company, Aurora, Ohio, allows plant personnel to conveniently operate and monitor the GT using the iFIX HMIs installed as part of the total CHP plant control system (PCS). The engine also can be operated from an OEM-supplied control panel at the unit or from an auxiliary panel in the data logging room.

The turbine control system receives and sends most of the data required for operation via the Ethernet. But it has some hardwired discrete I/O connections to the PCS as well to assure the highest level of safety possible. One of these links initiates automatic transfer to liquid fuel when gas pressure drops below a specified setpoint. Another provides for secure transfer of start permissive and trip signals from the HRSG control panel.

The Titans run to satisfy thermal load. Typically two engines operate in winter, one in summer; one unit is cycled during the shoulder months. Cornell's generators operate in parallel with the grid allowing the university to export some power in winter (perhaps 5-6 MW) when satisfying thermal demand means producing surplus electricity. In summer, Cornell is a net importer from NYSEG.

Cornell has a GT maintenance agreement with the OEM, called an IDSA or Intermittent Duty Service Agreement. Solar "takes care of everything," Peer told the editors, and provides an availability guarantee of 98%. A penalty/bonus arrangement penalizes lower availability, rewards higher.

The Rentech HRSGs are dual-pressure units capable of providing 46,000 lb/hr of HP steam (400 psig/600F) and 14,000 lb/hr of LP steam (nominally 60 psig/saturated) with no duct firing, and comparable numbers of 135,000 and 19,000 with duct firing at the maximum temperature of 1800F (Fig 4). Duct burners with 40:1 turndown capability were provided by Coen Company Inc, Tulsa (Figs 5, 6).

HP steam is delivered to the existing HP grid and supplies the existing backpressure turbines (refer again to Fig 1); LP steam is routed to the campus steam headers.

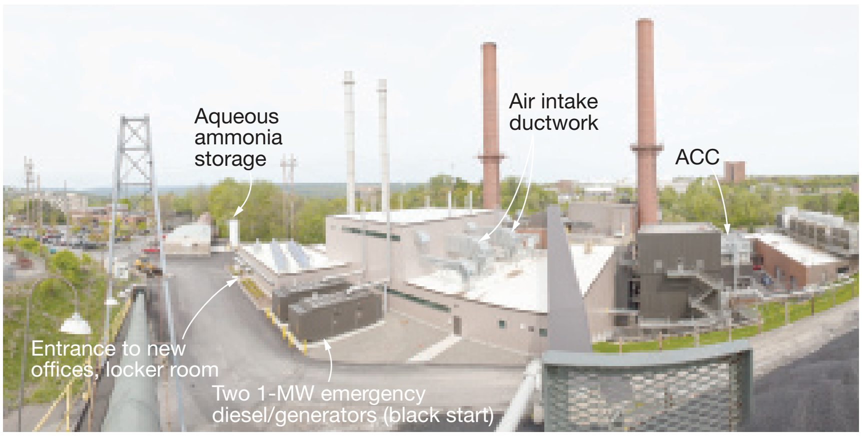
Rentech engineers Kevin Slepicka and Cory Goings told the editors that dual-pressure units of this size are uncommon. They said that Cornell was deeply involved in design and manufacturing decisions and wanted a separate LP boiler section because the university intended to "push" the HRSG on oil to prevent deposits on downstream heat-transfer surfaces. Thus LP steam can range from a nominal 60 psig to as much as 150 psig.

Goings said other features of the Cornell HRSGs are a CO destruction system, selective catalytic reduction (SCR) system to minimize NO_x emissions, waterwall surface in the firing duct and automation of drains, stack damper, etc. Primary goal of the waterwall surface is to reduce maintenance, Goings continued, there's not enough heat absorbed in this section to have a significant positive impact on efficiency.

Emissions limits for the CHP facility are 10 ppm CO, 2.5 ppm NO_x, and 5 ppm ammonia slip; annual limit on NO_x is 40 tons. There is no annual NO_x limit for the integrated powerplant (CHP plus fired packaged boilers). However, use of the gas/oil-fired boilers installed in 1992 is limited because HRSG duct burners are turned on before those units are called into service. Winter peak sendout today is 380,000 lb/hr, all but about 70,000 lb/hr of which can be handled by the HRSGs; summer-

7. Ammonia skid receives reagent for the SCR from a 12,000-gal storage tank located a couple of hundred feet from the CHP building (left)

8. Reception area for new offices faces coal pile planned for removal. Note aqueous ammonia storage tank in the distance and two black-start emergency generators alongside the building (below)



time demand is in the neighborhood of 55,000 lb/hr.

Rentech supplied a PLC-based boiler control system to monitor and regulate water levels and pressures in the HP and LP steam drums, duct-burner fuel modulation, steam temperature, operation of the SCR and associated ammonia system, etc (Fig 7).

The OEM also provided the aqueous ammonia storage facility located about 100 yards from the CHP building. It includes a 12,000-gal vertical tank for the 19% ammonia solution specified as the SCR reagent, as well as skid-mounted off-loading pumps and controls. System provides for leak detection and containment of spills. Impoundment drains to a spill sump, which discharges to the central steam plant's equalization/retention tank for treatment before controlled discharge to the sanitary sewer connecting to the Ithaca Area Wastewater Treatment Plant.

NO_x, CO emissions. Peer left "no stone unturned" in his review of design, manufacturing, and construction activities. To illustrate: Concerned about the long-term reliable performance of emissions controls, he hired Dan Ott of Environex Inc, Devon, Pa, to review the HRSG design. Ott is known to many readers for his presentations at user-group meetings (visit www.combinedcyclejournal.com/archives.html, click 3Q/2008, click "SCR working well? Don't take that for granted" on the cover).

Ott told the editors that Environex provided oversight on emissions control for Cornell with the goals of minimizing initial risk, assuring proper operation, and adequate maintenance access for both the SCR and CO catalyst systems. One of the things he focuses on is where boiler designers want to install the CO catalyst.

For CO catalyst, hotter usually is better for turbine applications, Ott said. If it's in a relatively "cool" location, there's a risk of deactivation even when small amounts of sulfur are present in the fuel, he continued. Roughly half of the units, by Ott's count, that have CO catalyst where the gas temperature is lower than about 600F have suffered sulfur poisoning. He added that catalyst can be deactivated in weeks, even days, when high concentrations of sulfur are present.

Steady deterioration of catalyst performance over three or four months usually points to sulfur contamination of fuel—including natural gas. Catalyst can be washed, sometimes with good results, but replacement or re-engineering is the only sure thing, Ott concludes. The Rentech design shown in Fig 4 satisfied Ott's acceptance criteria.

New digs. The CHP plant is located immediately adjacent to the central heating plant—a site historically used for Cornell's utility operations. Unlike most of the campus, the site is not generally visible to the community and requires escort by an authorized employee of the Utilities and Energy Management department for access.

The new addition is accessible on two levels. Major equipment is on the lower level which essentially is hidden from view because of the steep grade behind the heating plant. Direct entry into the approximately 3000 ft^2 of reception, office, training, and locker-room space is from the other side of the property and the architecture is consistent with that for a professional building (Fig 8).

Primary electrical gear is located on an intermediate level. Industrial decking also is located at this level over portions of the operating floor below, to facilitate access to upper portions of primary mechanical equipment (such as steam drums) and allow space for appurtenant equipment (Fig 9).

Inlet air filters for the gas turbines are located in a mechanical penthouse covering a portion of the building roof. Two stages of filtration are installed; the entire system was provided by Donaldson Company Inc, Minneapolis. Pocket prefilters cover one side of

9. Balcony facilitates access to steam drums and their appurtenances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10. Permanent walkway facilitates access to GT prefilters—an important safety best practice (left)

11. Gas turbine air inlet and its pulse-type inlet filters is to the right of the prefilters, shown from the back side

12. Gas receipt terminal alongside the steam condenser building assures particulates and liquids are removed from the fuel before it is forwarded to the GTs and boilers (left)

13. Operator Tom Brown is within easy reach of punch button to both stop gas flow and vent the line in an emergency. Two operators run the CHP facility and the existing infrastructure in the central steam plant. Total energy complex has a union staff of 22, including four I/C technicians (below)

the penthouse—a catwalk and permanent ladder allowing safe access to all filters (Fig 10). The primary filters are of the reverse-pulse type and located in the GT air inlet structure to the right of the prefilters in Fig 11.

Gas supply system. NYSEG's existing natural-gas distribution system could not support the needs of the CHP facility, requiring installation of a new 8-in.-diam gas delivery line from an interstate pipeline 3.2 miles from the university. Maximum operating line pressure is 600 psig. The pipeline project required, under New York State Public Service Law, an environmental review separate from that of the CHP plant. Gas supply is firm, non-interruptible.

A secure metering and regulation station designed, constructed, operated, and maintained by pipeline owner Dominion Resources is located on land owned by Cornell near where the interstate and delivery lines intersect. The university owns and operates a companion facility for adding odor to the gas and for conducting pipeline inspection and cleaning activities.

The dedicated pipeline terminates at a gas regulating station located adjacent to the steam condenser building (Fig 12). It consists of filters, pressure regulators, gas heater, vents, etc, needed to remove particulates and liquids from the incoming gas stream and reduce its pressure to the nominal 450 psig required by the GTs. A second pressure-reduction step provides the 30-psig gas required for duct burners and the packaged boilers.

Regarding safety, the regulating station is designed to instantly stop gas flow to the GTs, HRSGs, and packaged boilers on operator command and to vent safely the complete gas system downstream of the main stop valve. Emergency punch buttons, hardwired to the solenoids of actuators for critical valves, are within easy reach of plant operators in two locations (Fig 13).

Air-cooled condenser. It's helpful to have some knowledge of the makeup treatment, condensate return, and feedwater systems before getting into the details of the ACC and how it operates. Makeup treatment is relatively simple given the 400-psig/600F steam system. Before the CHP was installed, potable city water was filtered, softened, and degasified in the water treatment plant shown at the lower right in Fig 1 and pumped to a storage tank in the central heating plant where it was mixed with condensate returns from the campus network.

The makeup treatment system was reconfigured and upgraded as part of the CHP project. New softeners and degasifier were installed in the steam condenser building located under the ACC; the old water treatment building was gutted and a reverse-osmosis system installed at that location. Today, city water is delivered to the steam condenser building, softened, and then pumped through the RO membranes to the original storage tank.

Water withdrawn from the storage tank flows through the existing

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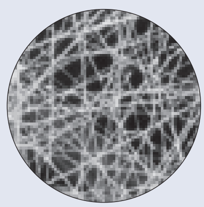

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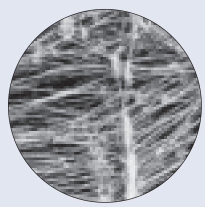

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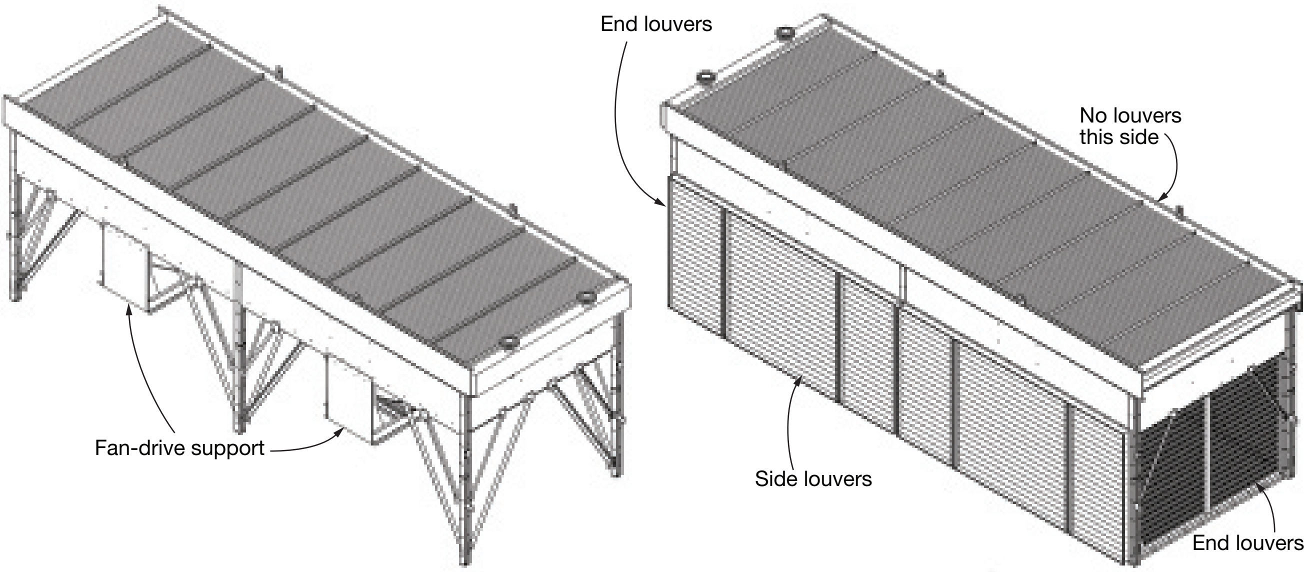

14. One bay of the ACC accommodates two fans (left). Louvers are wrapped around the bay that operates in winter as well as summer (right)

15. New substation with three 20-MVA transformers brings in 115-kV power from the utility system, provides 13.2 kV for the campus distribution system

deaerator in the old steam plant and sent directly to the HRSGs. The feedwater heater shown in the diagram, which uses LP steam as the heat source, is used only for the packaged boilers. Note that HRSG attemperator water pumps take suction from the storage tank to control steam temperature.

The ACC condenses steam produced in excess of demand. This can be expected during some transient conditions—such as when starting a GT or packaged boiler, or when steam demand is satisfied and there's a need for more electricity.

When steam output exceeds requirements, campus header pressure increases and controls act to limit the pressure rise and maintain header pressure at the high limit by automatically bringing the ACC into service. Note that pressure in the campus grid normally is maintained at about 35 psig in summer and 75 psig in winter.

However, to allow the thermal grid to absorb normal steam-load fluctuations and avoid excessive start/stop cycles of the ACC, pressure in the steam system is allowed to rise to 55 psig in summer and 95 psig in winter before the condenser kicks in. The allowable pressure rise can be adjusted by the plant operator at the iFIX HMI; allowable range is 5 to 25 psi.

The ACC, supplied by Smithco Engineering Inc, Tulsa, more resembles an air-cooled heat exchanger one would find in lube-oil cooling service, for example, than the A-frame type dry condensers typically used in F-class combined-cycle plants (Fig 14). Cornell's ACC sits on the roof of the steam condenser building and consists of two heat-transfer modules or fan bays, each with an air-to-steam heat-exchange tube bundle and two fans. The bays are designed to operate independently of each other.

In the summer, both modules may be required to operate at the same time to condense the maximum design heat load (90,000 lb/hr) when ambient temperature is high (91F design). In winter, defined as ambient air at or below 40F, only one of the modules is used. It is designed specifically for cold weather: Intake air louvers and preheaters prevent freeze-up. Maximum condensing capability for the one module in winter is 61,000 lb/hr of campus steam.

In the unlikely event the ACC is not available for service or the amount of excess steam exceeds the heat-exchanger's design capability of 107.4 million Btu/hr, a relief valve would vent steam to atmosphere until system pressure drops to the high-pressure limit.

Design pressure/temperature for the ACC is 150 psig/600F. The 1-in.-diam × 0.083 wall tubes of SA179 seamless cold-drawn carbon steel with imbedded aluminum fins have 149,400 ft^2 of total surface. Each 14-ft-diam, adjustable-pitch fan has ten aluminum blades; a 40-hp, 460-V, 1180-rpm motor drives the fan, via a V-belt reducer, at 198 rpm.

Two 1-MW diesel/generators, located near the CHP building's

reception area and offices in soundproof enclosures, are connected in parallel with the grid and provide black-start capability (refer to Fig 8). Plant operator can control and operate each emergency package locally, from a panel in the electrical room, and via the iFIX HMIs.

Two upgrade projects conducted during CHP installation involved the chilled-water and fuel-oil systems. The 4.5-million-gal thermal storage tank was rehabilitated to assure four hours of peak cooling capability. The cold water is produced by the centrifugal chiller plant located between the CHP building and the storage tank.

The existing No. 6 fuel oil tank was cleaned and refurbished to provide 700,000 gal of storage for ultra-low-sulfur distillate (refer to Sidebar 3).

Electrical upgrade

Major electrical work that accompanied the CHP installation included the following: (1) conversion of the Maple Avenue Substation from two 30-MVA transformers to three 20-MVA generators, (2) replacement of the main switchgear building, and (3) primary-circuit reconfiguration to support campus load growth.

The main driver for renewal of the substation was the need to have a grounded wye on the high side of the transformers to meet the NYSEG interconnect agreement for protective relays. Recall that when the substation was installed in the late 1980s, Cornell's generators were operating in parallel with the grid but not exporting to the utility.


Wanck

Today, the university typically exports some power in winter when the thermal demand is at its peak and the campus electrical system is configured to island if problems arise on the grid. Plus, Cornell is subject to certain grid security rules being enforced nationally by the North American Electric Reliability Corp because of its interconnect agreement with NYSEG. This limited editorial access to information on Cornell's electric distribution system.

The original transformers installed at the Maple Avenue Substation were configured with a delta high side and grounded-wye low side. An engineering review recommended the installation of new transformers and the sale of the old ones. The three-transformer configuration means the university now has an installed spare for future expansion. Note that all self generation is on the secondary side of the transformer and below the utility meter.

Another component of the renewal project was the installation of three zigzag transformers on the delta side, making the entire campus distribution system resistance-grounded and limiting any ground-fault current to 800 A.

Project Engineer Brian Wanck explained to the editors that the conversion from two to three transformers was accomplished with at least one transformer always serving load. Here's how: First step was to install one of the three new transformers between the switchgear building located at the far end of the substation (extreme right in Fig 15) and the first of the two original transformers (those closest to the powerplant).

Having the first of the new transformers in service allowed plant personnel to de-energize the original transformer on the opposite end of the substation and to remove what had become the middle transformer. Benefit was that the substation could be cleared of personnel and the de-energized transformer returned to service within one hour if it were needed.

New firewalls, containment pads, ground grid, and drain system, as well as new switchgear—all part of the Maple Avenue work—facilitated maintenance and improved safety. One important safety feature: The three-bus lineup with a ring connection from the end busses permits connection of any two busses. This means maintenance personnel can switch loads to another bus and work on a dead bus.

Temperature and humidity of the new switchgear building is carefully controlled; plus the building is under positive pressure so leakage is from the inside out. Another benefit: The upgrade made it possible to create a "self-healing" electrical system, meaning that faults are bypassed automatically.

When it comes to minimizing energy losses, the Utilities and Energy Management team sets a good example. For example, use of variable-frequency drives for pumps and fans selected for the CHP facility, and the implementation of other energy-saving ideas, reduces the house load to only about 400 kW in the shoulder months with one GT in service. CCJ

Make it right!

Air inlet houses seldom get the respect they deserve. Properly equipped and maintained, they help assure maximum output and high availability of your gas turbines (GTs). Yet they are almost an afterthought at many plants, the focus being on rotating equipment.

That's interesting because everyone reading this article knows their GTs require fuel and air to operate. And that there's relatively little you can do to fuel delivered by pipeline to improve engine performance and reliability except possibly heat it up a bit and remove particulates and moisture with fairly standard equipment.

You prepare air for combustion in much the same way: filter, add or subtract moisture, heat or cool. But there's a great deal most owner/operators can do to the air their compressors receive to improve overall plant performance. This report begins with suggestions on how to conduct a proper inspection of the air inlet house and decide what improvements are required and how quickly to do them.

Air filtration is next. It offers a backgrounder on the subject as well as the latest experience on the use of HEPA (high-efficiency particulate air) filters. They have the *potential* for keeping your compressor pristine and *possibly* eliminating the need for online and offline water washing.

Of course, the specific benefits of HEPA filters to your plant—such as little, if any, degradation in compressor performance over time—must outweigh their initial cost, which can run four or five times the price of conventional filters. Plus, personnel may be required to make more frequent inspections and be more vigilant about maintenance of the air inlet house, because air bypassing the filters would compromise compressor cleanliness.

Inlet cooling is a sure way to boost power output, but the effectiveness and value of a given method—evaporative cooling (media or fogging) or chiller—are influenced by ambient conditions, operating requirements, and commercial considerations. Evap coolers are most common and may be the easiest to operate and maintain. But care and upkeep, often forgotten, are required to maximize their cooling potential and avoid issues associated with carryover, poor water treatment, etc.

Fogging and its close relative, wet compression, often are criticized because they inject free water into the air stream. Many GT users fear that slugs of water may enter the compressor and damage the engine. Those with the greatest concerns seem to be owners of GE F-class machines, many of which have first-stage compressor blades that are particularly sensitive to moisture and easily damaged by direct impingement of water droplets.

But as with most everything, the selection of quality fogging equipment and its proper installation and maintenance are critical to achieving expected performance. Sizing and orientation of spray-nozzle holes, and the location/orientation of spray nozzles, are important considerations.

Chilling is well known for its ability to deliver air at 50F, or less, to maximize power production. However, it often is not considered seriously by merchant generators with energy-only contracts because of the relatively high capital cost and power drain.

But chilling can provide significant benefits to owners with contracts for capacity and some other ancillary services. Proof: Several post-bubble combined cycles recently have converted from evap cooling to chillers. The value proposition is improved when a thermal energy storage (TES) tank is integrated into the chilled water system. Another benefit of chilling: It reduces the airborne emissions per kilowatt-hour produced.

As you read this report, keep in mind that there may be very good reasons that your gas turbines' air inlet houses were (1) fabricated of materials not ideally suited for the plant location; (2) equipped with filters generally not recommended for ambient conditions at the plant site; and (3) not outfitted with the most effective cooling system for your operating paradigm.

Most often the decisions were

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purely financial; overriding goal was to get the plant in service as fast as possible and for the lowest cost. Long-term performance made little sense for a facility that probably would be flipped in the near term.

Your challenge under new ownership, and probably a different contractual arrangement with the ISO (independent transmission system operator), is to meet expectations with an air inlet system that may not be conducive to the goals. Make it right! As you'll see from the case histories included here, judicious upgrades and modifications can offer significant returns.

Inspection

What to look for and where

Air enters the gas turbine via structure that is referred to most often as the filter house, air inlet house, or inlet air house. In reality none of those names truly describes the function of this integrated package of systems and components vital to achieving GT performance and availability goals (Fig 1).

More accurate would be "gas turbine inlet-air conditioning facility." But for simplicity's sake the editors have opted for "air inlet system," which is what Donaldson Company Inc, Minneapolis, a leading supplier of GT filters and related components, calls it.

Judging from the open discussion at various user group meetings, there doesn't seem to be an "industry bible" on inspection and maintenance of air inlet systems. What you hear in these sessions typically is common-sense give and take: Here's what we found, here's how we found it, here's what we did to correct the situation. Nothing wrong with that, of course, but it only benefits those present in the room.

Hopefully, the methods and ideas offered here will help those who have not had the opportunity to share experiences with deck-plates personnel outside their respective plants. Most of the material below was compiled from notes taken during individual discussions with the following people:

- David Brumbaugh, founder and owner, DRB Industries LLC (www.drbindustries.com), Broken Arrow, Okla, has an extensive background in air inlet system inspection and maintenance. He is a member of ASHRAE (American Society of Heating, Refrigerating and Air-Conditioning Engineers) and is certified by the National Air Filter Assn as an Air Filtration Specialist.
- Barry D Link, aftermarket sales manager, Donaldson (www.donaldson.com).
- William Stacey Davis, Turbine Maintenance & Plant Services LLC (wdavis34@satx.rr.com), spent 10 years on the front lines of combined-cycle plants before forming his own consultancy at the end of June. Most recently he was plant manager for maintenance and outages at Guadalupe Power Partners—two 2 × 1 7FA-powered combined cycles in the PSEG Texas portfolio.

A weather hood is provided at the entrance to the air inlet structure for most gas turbines today. Its purpose is to protect filter elements from direct impingment by rain, snow, flying birds and insects, dirt, etc. Some are equipped with screens to prevent birds and large airborne debris (such as leaves, plastic bags, etc) from entering (Fig 2), moisture separators to remove large water droplets from the incoming air, and coalescing filters or drift eliminators to remove small moisture particles (such as fog).

Inspection goals are obvious: Check the condition of the rain hood and screens, moisture separators, etc, required for trouble-free operation. Also, the inlet heating system, if installed, to protect against icing and filter blinding in winter.


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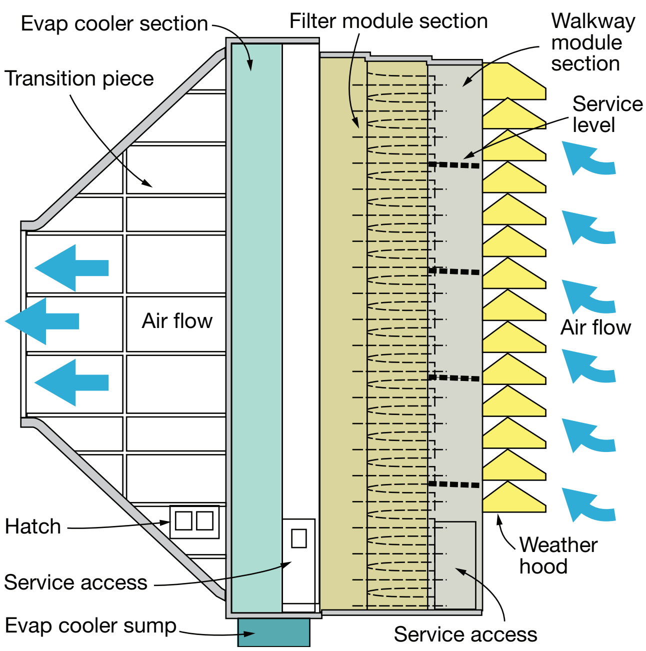
2. Absence of bird screens brings unwanted visitors



1. Air inlet house for a typical F-class gas turbine identifies components requiring periodic inspection

Air filtration

Condition assessment of the filtration system is considerably more involved and may require expert guidance if you're doing it for the first time. It's not very difficult to see a hole in a filter or other physical damage. Nor is it difficult to identify corrosion/rusting of metal components, which is of greatest importance if it occurs on the clean side of the media.

It's also easy to identify fouled media. But the dirt you see might not be a bad thing and not a reason for replacement. Dirt is evidence that your filters are doing their job. In fact, fouled media has a higher filtration efficiency than new, so you probably don't want to replace filters until the pressure drop across the filtration system is, say, 4 in. H_2O—1.5 in. H_2O for the prefilter if installed and 2.5 in. across the final filters. A delta p of 4 in. H_2O translates to about a 1.4% loss in output and about half a percent loss in heat rate. Check the pressure drop before beginning your inspection: No sense spending time assessing filter condition if replacement is imminent.

But pressure drop doesn't tell the whole story. Some filters—particularly those in peaking units—may show no visible signs of problems but should be replaced. Media degrades over time (it shouldn't be mushy or brittle), faster in some areas than others because of ambient conditions and airborne contaminants. If your filters have been in service more than three years, it's a good idea to remove a

couple of elements and have their physical properties tested. You can have this done by an independent lab for a nominal fee or by the filter supplier.

While you're checking the filter media, inspect holding frames and grid plates, evaluate retaining hardware (Fig 3) and assure proper torque, check the quality of the seal between the filters and the holding frame (caulking might be necessary), and for pulse filters, verify that the filter tripods (yokes) are straight and in the right position (12, 4, and 8 o'clock). Note that yokes often are bent by installers who stand on them; continuous supervision of ongoing work is important.

Readers with self-cleaning filters may recall that the cylindrical and conical filter sections have neoprene gaskets to help prevent air bypass. In particular, ensure that the gasket between the final filter and tubesheet is airtight. Also important: Verify that solenoid valves, pulse cleaning controls, compressed air, and electrical systems are functioning properly.

If you find rusted frames, you have two options: replace (Fig 4) or remove offending rust and apply a suitable coating. Regarding the latter, the method used to remove rust anywhere in the air inlet house is very important (Fig 5). Knowledgeable plant maintenance personnel warn against a grit blast because it is virtually impossible to remove all the foreign material before restarting the engine. Use a needle scaler instead.

An aggressive cleanup is critical to protect the turbine. Broom clean does not pass the cleanliness test. Vacuum brushes and complete wipe-down with lint-free rags before recoating are recommended. A premium two-part epoxy seems to be the preferred coating system.

Leakage paths for unfiltered ambient air to enter the compressor include (1) poor sealing between filters and support frames and between the frame structure and the walls, floor, and ceiling of the compartment, (2)

3. Galvanic corrosion from moisture ingress quickly chewed up metal portions of the original pulse-type filters

AFC-Advanced Filtration Concepts

4. Framing for new static (barrier)-type filters is of stainless steel to minimize corrosion potential

AFC-Advanced Filtration Concepts

5. Corrosion of air-inlet floor must be addressed to prevent metal from flaking off and being ingested by the gas turbine

DRB Industries

holes in the compartment's walls, floor, and ceiling, (4) access through compartment drains, (5) at joints in the ductwork, etc. They typically can be identified by standing inside the darkened air inlet house on a bright day and looking for sunlight. Another method is to pressure wash the ductwork from the outside and look for water ingress.

That's the easy part. An important part of the inspection process, particularly if you are new to the plant and are in a supervisory position, is to check the arrangement of the filtration system and verify its suitability based on current ambient conditions. To illustrate: Self-cleaning filters, although installed may not be appropriate for plant locations where the humidity is high.

Verify, too, that air velocity is uniform across the inlet duct and that the face velocity across the filter elements is within design limits. A couple of experts told the editors that they have encountered air inlet houses that are undersize for the service. The result: Velocities significantly above those recommended for the filters, evap media, and mist eliminators.

Telltale signs of high velocity include corrosion of silencers, streaking on side walls downstream of the mist eliminators, standing water, filters that have blown out, and compressor fouling caused by particulates in the air bypassing the filters.

Use an anemometer to check air velocity across the filter face. If the plant doesn't have an anemometer, buy one; only costs about a grand. The OEM's specification for your air inlet house should provide the design velocity for comparison purposes.

Where evap coolers are installed, Munters Corp, Ft Myers, Fla, the leading supplier of this equipment for GT applications, recommends a face velocity of 525 in the middle of the filter field, 650 ft/min at the corners. These numbers assume a drift eliminator is installed.

Don't be surprised if you find velocities at the corners of the filter array and the evap-cooler media that are twice what you measure in the center. Re-engineering of the inlet structure may be necessary to correct the problem and properly protect the compressor both from water carryover and from corrosion products that spall off ductwork, filter supports, inlet silencers, etc.

If re-engineering is in your plant's future and the air inlet structure must be rebuilt—it's not a big deal, really—be sure to evaluate beforehand how the current materials of construction have performed. If you're seeing corrosion, or peeling of galvanized coating, consider stainless steel for new construction—preferably Type 316L.

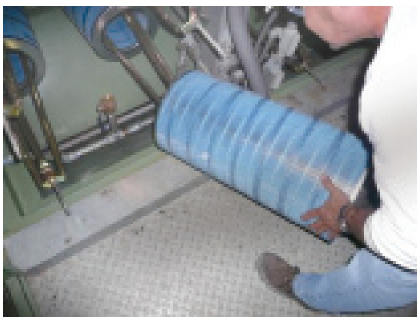
This also is a good time to review the plant's experience in maintaining the air inlet system. Perhaps access to the filters can be improved with addition of more doors, permanent stairs and platforms, etc. Think about improving safety as well with handrails, guardrails, etc. Look back through the OEM's advisories and technical information letters as well and implement those recommendations.

One inlet-cooling expert the editors spoke with suggested that users might want to consider eliminating inlet silencers if the plant is in a remote location and sound attenuation really is not necessary—especially so if a fogging system is installed. Reason: Silencers, or any other component in the air flow path downstream of fogging nozzles, promote droplet agglomeration. And that includes trash screens. All are a potential source of hard particles from corrosion and erosion processes.

Open discussions at the many GT user-group meetings often acknowledge compressor damage from water droplets and hard particles associated with having trash screens, but none, to the knowledge of the editors, identified the trash screen with preventing a catastrophic loss by stopping foreign material from entering the unit.

Hire a pro to do the design work for the re-engineering effort. And do some research on your own. Confer with colleagues at the next user-group meeting. Also troll the online discussion forums supported by the various user groups to identify a couple of plants that have recently done work like you are planning and connect by phone to learn more about what works, what doesn't.

When new filters are necessary, resist the temptation to make a snap decision and simply replace "in kind." Or purchase based on lowest first cost. In the three years or more that your filters have been in service there may have been changes in ambient air quality and operating schedule that could impact filter selection. Plus, offerings from the filter vendors have changed. For example, HEPA filters recently have emerged as a viable alternative where continuity of compressor cleanliness is a business advantage. It's certainly worth starting with a clean sheet of paper and making a proper evaluation.


Donaldson

6. A pulse-type filter, typically specified for dry environments, is installed

Who's going to replace your filters (Fig 6): plant staff, filter supplier, contractor? This is a big job for a 7FA—450 pulse-type filters by one maintenance manager's count (each consisting of a cylindrical and conical section)—especially the first time, when you have to figure out how best to accomplish the task.

Use of contractors sometimes draws a caution flag in industry discussions because of unsatisfactory experiences. Who can't change filters? You don't want to learn. So, unless you know the contractor or can validate its competency you might want to pass. The filter manufacturer is a safe choice as is your staff.

If plant personnel are available and you choose to handle the project in-house, here are a few questions to ask yourself:

- How will you get the new filters—they are not light—to where they're needed? An extended-reach aerial platform is one idea.
- Do your old filters qualify for disposal in any landfill or must they be shipped to a special disposal facility? What tests are required for a disposal permit and what laboratories do this work?
- What are the paperwork requirements for transporting the old filters to a certified disposal facility? Insurance?
- How will you get the old filters into the disposal container without releasing fine dust, which might be considered a health hazard? An enclosed chute to a dumpster is said to work well.

Inlet cooling

Of the three inlet cooling options, evap coolers and foggers require particularly close inspection during a walkdown of the air inlet house. Where chillers are installed, there only are a few heat-exchange coils to look at.

Evap cooler. Inspection of the air side of an evaporative cooler is similar in some ways to that described earlier for air filters. For example, you want to verify there are no gaps between media segments that would allow air and water droplets to bypass the cooler. But here you also want to verify there is no water bypassing the media because that would reduce efficiency. Also, carefully check water flow rates and distribution. Dry streaks on the media are indicative of poor distribution.

Look at the walls of the air inlet house downstream of the drift eliminator. If you see streaking, something's not right. Cause could be high air velocity, water bypassing the evap cooler, and/or a defective drift eliminator. Important to locate the source of the problem and correct it.

Evap media should last three to five years (depending on conditions), according to the experts at Munters. It's pretty difficult to miss scaling of the media (note the white scale at the top of the media in Fig 7) and fouling, such as that evident in Fig 8. When you see problems such as these, both of which adversely impact efficiency and reduce the effective lifetime of media, call the plant chemist. Tighter water chemistry should prevent further scaling; use of a proper biocide will eliminate microbiological activity. Sample water regularly—perhaps weekly—to assure system chemistry is within guidelines.


Donaldson

7. Scaling at the top of the media (frosty deposit) impedes proper operation of an evap cooler


DRB Industries

8. Microbiological fouling reduces efficiency and media life, can produce objectionable odors downstream, and can promote corrosion of framing

One expert quantified the impact of severe scaling this way: Blocks forming the top row of the media weighed in at 150 lb, or 30 times their original weight. Air velocity below the scaled media was in excess of 900 ft/min.

Other signs of media deterioration that demand your prompt attention include a "mushy" rating on the "feel" test and a delta p across the media that is double the as-installed pressure drop.

In addition, remember to do the following:

- Check framing, drift eliminator, sump, piping, pumps, and support systems for corrosion. Repair as necessary.
- Verify integrity of seals, gaskets, and caulking.
- Flush the sump and piping system thoroughly annually or more frequently.
- Send samples of the media and water to the evap-cooler supplier annually for evaluation.

Fogging system. If you have just taken a position at a plant with fogging system and you have no experience with this cooling technique, it's important to verify, to the best of your ability, spray patterns and uniformity of flow among the various nozzles. It is considered good practice to send nozzles for flow testing annually, or every couple of years if they see relatively little service time.

Make sure the spray patterns do not directly impinge on the walls of air inlet house. This would cause the fine mist particles to agglomerate and possibly cause problems by slamming into compressor blades and vanes. Check, too, the material used to fabricate the ductwork. Galvanized steel can present problems because the high-purity water used for fogging is so aggressive that it can remove the zinc present and deposit it on inlet guide vanes and other compressor parts.

Having a window at the bellmouth for visual inspection of pooling or running water during operation is a good idea. If one is not installed consider it. Flowing water at the inlet can be avoided by setting the fog-system control parameter so the system always "under-fogs." Translation: Maintain the air flowing into the compressor at slightly less than 100% saturation.

Finally, the fogging pump skid located outside of the air inlet house must be checked as well. Verify proper operation and seal integrity for the pumps, instrumentation, and other components in these very-high-pressure fluid systems.

Filtration

Static or pulse filter: What's best for your plant? Have you ever considered HEPA?

Subscribers who began working at GT-based powerplants within the last 20 years may not be aware that many gas turbines installed in the 1960s and 1970s for peaking duty don't have inlet filters. Most do have bird screens, however. These relatively low-power machines might run 50, 100, possibly 200 hr/yr to meet peak demand. So how much of a return, if any, could there be on an investment in air filters?

Readers responsible for such ageing infrastructure are lucky because deciding on what filters to buy for today's high-efficiency GTs is a challenging task. Some reasons why maintenance managers get frustrated:

- Air-inlet filter standards do not focus on the specific needs of GT owner/operators. The same standards are applied equally across unrelated markets —such as HVAC, pharmaceutical clean rooms, and powerplants.
- There are European- and US-based standards organizations and they have different specifications.
- Some methods for measuring filter effectiveness—arrestance (or weight of captured particles), for example—are meaningless for fine-dust filters that do most of the work protecting against compressor fouling. The small particles of greatest importance do not weigh much, but they outnumber large particles by several orders of magnitude.
- Standards and test methods are continually evolving.

In addition, there are filter-media options to consider—synthetics versus cellulose, nanofibers versus microfibers, etc. The optimal selection for your plant depends on ambient conditions (table). For example, what works best in a dry or wet clime, near seacoast where salt is entrained in the air, near industry, in a pristine location?

As with everything you buy, be wary of the low-cost sales proposition. No one wants to spend more than necessary, but the purpose of the filters is to protect the most important piece of equipment in the plant. A simple cost/benefit analysis will prove that it's worth paying a little more to assure high availability and a clean compressor to maximize performance.

Simplifying selection

While it's certainly worthwhile doing some background reading on filters, be prepared for an onslaught of material if you simply "Google" the subject. At the most basic level, filter choice comes down to either a static (barrier) or a pulse (self-cleaning) design. Pulse systems usually consist of some form of weather protection followed by a deep-pleated cylindrical and/or conical filter. The filters are cleaned periodically by means of a reverse pulse of air.

Static systems typically have weather protection as well, plus prefilters to remove coarse contaminants and high-efficiency filters to get the fine dust. There are many types of each to choose from. Because static filters do not self-clean like the pulse filter, when they reach a certain pressure drop replacement is necessary. Prefilters are changed more frequently than high-efficiency filters, which may last anywhere from 8000 to 24,000 hours depending on the environment, operating duty, etc.

Another option: Swap out the conventional fine-dust filter with a HEPA filter, or install a HEPA downstream of the fine-dust filter, if eliminating performance degradation and/or online and offline compressor washes are critical goals.

The standards recognized today for GT filter specifications are ASHRAE 52.2 and the European Committee for Standardization's EN779. If you're going the HEPA route, add EN1822 to the list.

ASHRAE filter designations are MERV (Minimum Efficiency Reporting Value) 1 to 16, which you're probably familiar with. MERV 2 through 4 are specified most often for prefilters; MERV 13 through 16 for fine filters, with 14 and 15 most popular.

The equivalent filter designations for EN779 are G2-G4 for large particles and F7-F9 aligning with MERV 13 through 16.

HEPA designations H10, H11, and H12 associated with the limited number of powerplant applications to date are specified by EN1822, which was updated his year. The existing standard for fine filters, EN779, cannot classify HEPA filters because HEPA-filter performance exceeds the testing capability of the standard. Think of this as trying to measure 1 in. with an ungraduated 12-in. rule.

Both the ASHRAE MERV 1-4 and EN779 G1-G4 classification tests reflect the *weight percent* of standard synthetic dust particles in the size range of 3 to 10 microns removed by the filter without exceeding a speci-

Filtration system selection guide

Environment	Dust level	Weather protection	Filtration system
Hot and dry	High	Weather hood	Pulse
Hot and dry	Low/medium	Weather hood	Static
Humid	All	Weather hood	Static
Coastal	All	Weather hood/ separator	Static, downstream separator
High rainfall	All	Separator	Static
Ice and snow	High	Snow hood	Pulse
Ice and snow	Low/medium	Snow hood	Static, anti-icing

fied pressure drop. Both the MERV 1 and G1 filters collect less than 65% of the particles by weight, MERV 2, 65% to 70%; MERV 3, 70% to 75%; and MERV 4, more than 75%. By contrast, the G2 range extends from 65% to 80%; G3 from 80% to 90%; G4 filters capture more than 90% of the particulates by weight.

For establishing fine-dust filter classifications, ASHRAE uses synthetic dust particles in the range of 0.3 to 1 micron with an average size of about 0.65 microns. However, the percentages here refer to the percentage of particles removed rather than the weight percent removed for MERV 1-4.

The ratings: MERV 13, fewer than 75% of the particles from 0.3 to 1 micron are removed; MERV 14, between 75% and 85%; MERV 15, between 85% and 95%, and MERV 16, more than 95%. MERV 13-15 also remove more than 90% of the particles in the inlet air between 1 and 10 microns; MERV 16 removes more than 95%.

The EN779 fine-dust classifications differ from ASHRAE in that the Europeans use a synthetic dust comprised of 0.4-micron particles—in effect a more demanding test than 52.2. An F7 filter captures between 80% and 90% of the particles, F8 between 90% and 95%, and F9 more than 95%.

While the ASHRAE and EN779 standards appear challenging at first glance because of the high percentages, keep in mind that any filter with a MERV rating could allow virtually all particles smaller than 0.3 micron to pass through and still meet the specification; for EN779 classifications, particles smaller than 0.4 don't have to be removed from the air stream.

Perspective is important here: The normal particle distribution in a typical urban ambient air reveals that there are 100 times more 0.1-micron particles than 0.5-micron particles. This is why you can buy a top-of-the-line MERV 16 filter and still watch compressor performance drift downward until you wash online and/or offline.

The EN1822 standard for HEPA filter classification differs significantly from ASHRAE 52.2 and EN779. Note that there is no comparable US standard at the present time and there are only a few laboratories capable of measuring the very small test particles required for HEPA classification. Test equipment is quite expensive.

HEPA ratings as defined by EN1822 are based on the minimum capture rate of the most penetrating particle size (MPPS). In plain English, MPPS is the particle size that has the lowest capture efficiency for the media tested. The defining size usually is in the 0.05-0.2 micron range, which coincidentally is the range of particle sizes oft associated with compressor fouling issues.

So for a standard test using dust particles from 0.04 to 0.5 micron, you might capture 99.95% of 0.05-micron particles, 99.90% 0.07-micron particles, 99.85% of 0.15-micron particles, 99.5% of 0.13-micron particles, etc. In this case the MPPS would be 0.15 micron.

Rules of classification require that MPPS particle capture (in percentage of particles) must be at least 85% to be rated H10, 95% for H11, and 99.5% for H12. The 99.85% capture of MPPS 0.15-micron particles for the example described qualify the filter for H12 status.

Perhaps the most worthwhile and current reference on GT air inlet filters for powerplant personnel can be downloaded from the Gas Machinery Research Council website at www.gmrc.org. The 122-page "Guideline for Gas Turbine Inlet Air Filtration Systems," prepared by Southwest Research Institute and published April 2010, is a comprehensive effort, both practical and scholarly, that offers something of value to everyone involved with gas turbines.

It begins with the consequences of poor inlet filtration; discusses all aspects of filter selection, including life-cycle cost analysis; operation and maintenance; and testing, which gives details on ASHRAE 52.2, EN779, and EN1822.

HEPA: an alternative to compressor washing

Relatively few US gas-turbine owner/operators were familiar with the use of HEPA filters for GT air-inlet applications before the V Users Group's 2007 meeting in Glen Cove, NY. It was there that RWE npower's John Macdonald explained to the industry how high-efficiency filters could eliminate the need for online and offline compressor washing. That sounded important to several owners of GE F-class turbines in the room who had been told washing could be an underlying cause of R0 blade failures.

One concern of attendees was the potential for high pressure drop across the filter bank and its associated cost. But the experienced Macdonald, who is based in the power producer's UK central engineering offices, assured the group that the delta-p impact is not as great as most might think—at least based on his rigorous analyses.

While an H12 filter could increase the pressure drop across an existing inlet filtration system by 50%, he said, the degradation in power production is relatively constant over time and the plant would not get the "big hit" caused by fouling.

At the time, he and his colleagues were evaluating the addition of a HEPA stage to the filtration systems for Didcot B's gas turbines. They were encouraged by the favorable experience with HEPAs at ScottishPower's Damhead Creek Power Station in southern England, and International Power's Saltend Power Station, near Hull in the northeastern part of the country. Neither plant was washing online or offline.

Macdonald described the arrangement of air filters for RWE npower's Didcot B, which consists of two 2 × 1 combined cycles capable of producing up to 1360 MW. The facility is located alongside Didcot A, a 2000-MW coal-fired station. The inlet air houses for the Didcot B GTs have rain hoods, followed by coalescers, and two filtration stages (prefilter and F8 final filter). Coalescers were washed periodically; life of the final filters was about two years. Using this filter lineup, compressors were online washed approximately weekly and offline washed periodically.


Macdonald

The alternative considered by RWE: Retain the coalescer, prefilter, and swap out the F8 filter with an H10. This project was completed only recently, Macdonald told the editors in mid August, so no operating data are available yet. If expectations are met, the H10s could be replaced with H11s or H12s when they reach end of life.

A similar retrofit project is being evaluated at Little Barford Station 2. That site has two GE 9Fs with two-stage static filters, one operating with F9 final filters and the other with H10s. Despite the relatively short operating period for comparison purposes, performance of the H10 has been measurably better.

Compelling evidence that RWE npower views HEPA filters favorably: Combined-cycle units under construction at Staythorpe in Nottinghamshire and at Pembroke in West Wales are equipped with H12s. The first of four Alstom GT26B-powered, 425-MW, 1 × 1 combined cycles at Staythorpe began acceptance tests in August. Plans are for the entire station, located on a compact brown-field site and former location of two coal-fired units, to be operational by year-end.

The five Alstom GT26-powered, 400-MW, 1 × 1 combined cycles at Pembroke are scheduled for operation in 2012. This site previously supported an oil-fired station since decommissioned.

A little digging revealed that HEPA filters had been installed on several aero GTs—both onshore and offshore—years before they were adopted by the large frame engines. American Air Filter International, Louisville, told the editors about land-based GE aeros being equipped with their HEPA filters as far back as May 1992; an offshore Frame 5 was so equipped in 1981.

Mitsubishi experience. Interestingly, AAF is part of a Japanese consortium that considers itself the world's leading provider of air filters. This connection undoubtedly has facilitated a relationship with Mitsubishi Power Systems. Several M501F, M701F, and M501G machines have been installed in Bangladesh, Hong Kong, Spain, Taiwan, and Mexico with HEPA filters.

A top-level Mitsubishi manager told the editors, "We encourage our clients to use HEPA filters. We have impressive examples in Mexico where one client has them and another next door (exactly the same configuration) doesn't. Comparisons of compressor fouling and performance deterioration are simply amazing."

HEPA filters reduce or eliminate the need for online and offline washing, he continued; however, this is an economic decision for the customer to make.

Mitsubishi offers a three-stage system which makes use of the existing prefilter and standard filter and adds a third HEPA stage. But considerable effort is required to do this. For example, the air inlet house has to be made larger and structural steel must be reinforced. To avoid major modifications, the company developed an upgraded HEPA filter that can be retrofitted into the filter housing designed for two-stage systems. Typical replacement interval for both systems is one year. Both are designed to remove 99.97% of the particles 0.3 microns and larger.

Careful monitoring both of a turbine outfitted with the upgraded HEPA filter, and a sister unit at the site using conventional filters, revealed an average improvement in output of the HEPA-equipped combined cycle of 1.7% over the two-year study period; average plant efficiency improvement was 1%.

Translating this to dollars for a M501G-powered 1 × 1 combined cycle operating 6000 hr/yr, Mitsubishi engineers came up with an annual increase in net operating revenue of $1.6 million and a $250,000 annual penalty for the higher-cost HEPA filters. Net gain: $1.35 million. The OEM's numbers assume HEPA filters are four times as expensive as conventional filters.

Gore. About 10 manufacturers are actively pursuing GT owner/operators for their replacement filter business. But only W L Gore & Associates Inc, Elkton, Md, seems focused on HEPA filters at present. Perhaps the others believe the cost hurdle is too difficult to overcome: Turbine air filters often are considered a commodity with price the deciding factor in the selection process.

Gore says it has the best HEPA technology. "Field experience with advanced membrane-based HEPA filtration," a paper by the company's Marc Schroeter and E.ON UK's Peter Hall presented at Power-Gen Europe 2010 last June, reports Gore's filter media offers a significantly lower pressure drop and longer effective lifetime than competitors' products.

The company's three-layer HEPA filters feature an expanded polytetrafluoroethylene (ePTFE) membrane for removing very small particles, water, and dissolved salt crystals.

Referring to Fig 9, note that the prefilter layer removes most of the coarse and submicron particles and retains them with a minor pressure-drop penalty. Depth filtration assures long filter lifetime.

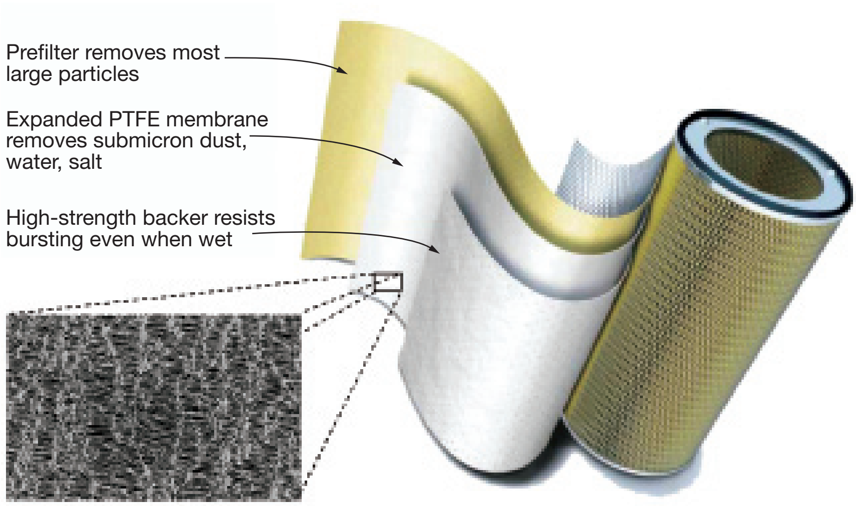
The ePTFE membrane reportedly provides an extraordinarily large surface area and is not susceptible to water ingress. The authors said its nanometer-scale fibrils and nodes minimize pressure drop because of "slip flow." Here's how they explain the phenomenon: The drag force on a nanometer-scale fibril is smaller than that for micrometer-size fibers used in other HEPA designs and the molecular movement of the air molecules contributes to the overall air flow, thereby reducing resistance.

Finally, a high-strength backer provides high burst strength even when wet. Wet burst tests of cartridge and panel filter elements containing this media exhibited burst pressures upwards of 30 in. H_2O. The combination of the three layers is pleated and integrated into standard cartridge or panel designs for installation in most existing filter houses without difficulty, according to the presenters.

Gore recently announced a new Z-panel design (Fig 10) that the presenters said had half the pressure drop compared to an H12 V-shaped panel with microfiber glass media. Another benefit of the Z- or V-shape panels with membrane-based media now commercially available: Only one prefilter stage—either G4 or F5 (EN 779 class)—is required so no structural mods of the air inlet house are necessary.

The filter manufacturer first began testing its membrane-based media nearly six years ago in Europe. All sites reported the elimination of compressor fouling as well as a filter lifetime similar to the F8 or F9 cartridges used previously.

Site 1, an industrial plant on the West Coast of England operating a 31-MW Rolls-Royce RB211. Single-stage filter house had 112 pairs of F9 conical/cylindrical cartridges. Plant operator E.ON UK was experiencing



9. Membrane-based filter media with H12 rating has nanometer-scale fibril compared to micrometer-size fibers in conventional media, thereby reducing pressure drop across the filter bank power loss up to 3 MW before offline washing every other month.

Results with Gore filters installed in March 2008 with an additional prefilter wrap: No drop in output was reported, no compressor washing was necessary. Filters were replaced after 7600 hours, comparable to the F9s which averaged 7550 hours.

Site 2, an industrial site in Spain about a mile and a half from the Mediterranean Sea operating a GE 9FA. Air inlet house had 700 F9 conical/cylindrical cartridges; corrosion and compressor fouling were issues. Since installation late in 2009, the Gore HEPAs have met expectations (no decrease in expected power output, no significant increase in pressure drop across the filter stage).

Site 3, at a desert location in the Middle East offers insight into pressure drop through HEPA H12 cartridge pairs serving a 7.9-MW Siemens SGT-300 (formerly known as the Alstom Tempest). These filters are continuously pulse-cleaned—every 20 seconds two cartridge pairs are hit with 100-psig compressed air to release collected coarse particles. Delta p through the filters after seven months of operation still was an acceptable 0.96 in. H_2O (260 Pa); performance degradation was nil.

Site 4, an industrial site with a GE Frame 6B offers early data on the performance of the Gore Z-panel filter element shown in Fig 10. With G4 prefilters and an F8 stage clipped on to the final H10 filter, operators were online washing monthly, offline quarterly.

Last fall, the 120 panels were swapped out with 78 Z and 42 V panels with the membrane-based media; 66 G4 bags were again selected for the prefilter. Note that space restrictions in the filter house militated against using Z panels throughout. Results for the first four months: pressure drop through the prefilter, same as before; delta p through the final filter stage, 1.4 in. H_2O (350 Pa); no compressor efficiency loss; no decline in power output. Update: After 10 months of operation, the final-filter differential pressure is about 2.4 in. H_2O (600 Pa).

Site 5, TransCanada Corp's Grandview Power Plant, New Brunswick, Canada. Plant Manager Rick MacDonald told the editors his facility has two LM6000PDs (COD December 2004) running base load (8400 hr/yr) in cogeneration service on pipeline gas. Grandview is located at sea level, less than a mile from the ocean, adjacent to a refinery, and in close proximity to other industry. Think for a moment about what witch's brew of contaminants could be entering the air inlets of those GTs.

Gore HEPA filters were installed in Unit 2 two years ago because of performance issues that required a shutdown about every six weeks for an offline wash to recoup the 1 to 2 MW lost because of a dirty compressor. HEPA results impressive over the next year. The upgraded engine was washed every four months when

10. Z- and V-shaped panels with membrane-based media and one prefilter stage are now commercially available

11, 12. Offline soak wash effluent sample for Unit 2 reflects 2505 continuous base-load hours with H12 HEPA filters (left); sample for Unit 1 reflects 1480 base-load hours with conventional filters (right)

mandatory borescope inspections were conducted—simply because it was convenient to do so.

MacDonald said there had been no significant performance degradation; likewise, after the washing there was no uptick in output. The plant manager added that he believed the GTs could go six months or longer between offline washes.

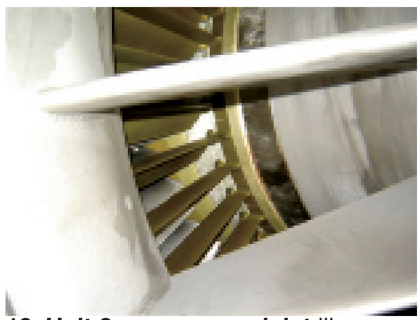
Proof was offered by sampling the washing solutions from both engines. Fig 11 shows the milky white sample (with a hint of gray) from the HEPA-equipped engine, Fig 12 the black sample reflecting deposits removed from the compressor of the engine with the standard filter. Fig 13 shows the Unit 2 compressor inlet after 10,600 hours of operation.

Standard filters on Unit 1 were replaced with HEPAs in October 2009 and the generator cooling-air filters were changed out as well. Fig 14 shows the pleated prefilter insert used to protect the HEPA cartridges from large particulates. MacDonald thinks he'll probably get three years of service from the Gore filters, which is what he was getting with the original product.

MacDonald ran through the economics that justify HEPAs for his engines. As a starting point, he assumed that HEPAs cost five times that of a leading conventional filter. Taking credit for the water and soap saved, plus the disposal cost of the spent washwater solution, MacDonald said HEPAs cost four times more than conventional filters.

For Grandview, which has a tolling arrangement, the ability to maintain clean-engine performance means the plant can produce and sell more power throughout the year. The additional revenue, plus eliminating the expense of shutting down every six weeks, more than offsets the nominal $1000 per month more the plant pays for the HEPAs over a three-year cycle.

MacDonald stressed that the economic analysis for virtually every situation will have a different result. It depends primarily on how a plant is paid for services rendered. The facilities benefiting most probably are those able to bid a higher capacity into the ancillary services market.



13. Unit 2 compressor inlet like new after 10,600 hours of operation with HEPA filters

14. Pleated prefilter protects HEPA from large particles

Inlet cooling

Not meeting expectations? Fix or replace. Don't accept subpar performance

There are several reasons your inlet cooling system may not be meeting expectations. Among them:

- Poor O&M practices.
- Installed equipment not utility-grade.
- Old age: System antiquated or obsolete.
- Inappropriate technology for plant's ambient conditions and/or for meeting the terms of the current power-supply contract.

A proper inspection, as described in the first section of this report, provides information vital to deciding whether it is in your company's best interest to overhaul the existing inlet cooling system or to replace it—in kind, or with another technology.

If you're involved in this process, it might be worthwhile to review the basics of the alternative inlet cooling technologies and to learn more about the latest offerings from the leading suppliers. A good place to begin is by reading the thumbnails below of the cooling methods used most frequently on the front end of gas turbines dedicated to power production. More detail is available on the website of the Turbine Inlet Cooling Assn (TICA) at www.turbineinletcooling.org (sidebar).

Evap coolers are specified most often. They cool via evaporation of water from the wetted media into the GT inlet air. Humidification is accomplished as water flows over the wetted media and air passes through it. The water may require treatment, depending on the GT manufacturer's specifications. A honeycomb-type medium is most common.

Wetted media can cool the inlet air to within 85% to 95% of the difference between the ambient dry-bulb and wet-bulb temperatures. It is one of the least-cost cooling options, despite its high water consumption. Primary disadvantage is that the extent of cooling is limited by the wet-bulb temperature and is, therefore, weather- and climate-dependent. Wetted media is most efficient in hot, dry climates and less effective when ambient humidity is high.

Fogging is the second most popular evaporative technology. It saturates the GT inlet air by spraying very fine droplets of water into the air stream. Droplet size depends on the desired evaporation time and ambient conditions. Fogging typically requires demineralized water.

Fogging systems can cool the inlet air to within 95% to 98% of the difference between ambient dry-bulb and wet-bulb temperatures, so it's slightly more effective than the wetted media. The capital cost is comparable to that for the wetted media and the technology has similar limitations and disadvantages.

Over spraying, also known as wet compression, adds more "fog" to the inlet air than can be evaporated under ambient conditions. The air stream carries the excess fog into the compressor section of the GT where it evaporates, cooling the compressed air further and creating extra mass for boosting the GT output beyond that possible with the other two evaporative technologies discussed above.

Chillers can cool the inlet air to much lower temperatures than those possible with evaporative cooling and can maintain any desired inlet air temperature down to 42F, independent of ambient wet-bulb temperature. It works this way: Inlet air flows across cooling coils within which either chilled water or refrigerant is circulated. Mechanical chillers powered by electric motors or steam turbines generally are preferred over absorption systems for powerplant service.

Cold water can be supplied directly from a chiller or from a thermal energy storage (TES) tank containing ice or only chilled water. TES typically is specified when cooling is required for a limited number of on-peak hours, because it reduces the chiller plant's installed capacity requirements and overall capital cost. Also, TES allows the plant to export maximum power on peak because it is charged at night using off-peak electricity.

The primary disadvantages of mechanical refrigeration compared to evaporative cooling technologies: Higher capital cost, larger footprint, and higher parasitic power load. The impact of its power requirement may increase overall plant heat rate if TES is not used.

It's not just about technology. The editors caught up with John Kraft, president, Caldwell Energy Co, Louisville, at a recent meeting of the Combustion Turbine Operations Task Force (CTOTF) and asked him to put on his TICA vice chairman's hat to discuss the challenges GT owner/operators face with respect to inlet-cooling decisions. By way of background, Caldwell is well known in the industry for its fogging systems.

Kraft summed it up this way: Many considerations impact decisions on turbine inlet cooling; technology is only one of them. First concern of the owner: Does it make economic sense to increase plant output? If not, put away your paper and pencils.

If you pass the owner's "dollars and sense" test, carefully read the plant's operating permit. Anything in it that would militate against the project envisioned?

Next, what will the regulatory authorities think about your plan to boost output? If you will burn more fuel, the project probably will not be viewed favorably. Permitting could be very difficult, possibly a deal killer. In Kraft's words, permitting is a negative driver for TIC improvements.

Water use may be an issue in some areas, particularly if a chiller package with wet cooling is specified. Air-cooled condensers might not work financially.

If you're still in the game at this point, call on the turbine OEM to be sure the proposed inlet-cooling system is suitable for your unit without operating restrictions. Wet compression is one alternative that could require careful analysis by the manufacturer's engineers.

There are many "ifs" in the foregoing because that's the reality of trying to improve a permitted plant. Where the economics are compelling for a given project, you generally can overcome regulatory concerns with hard work and an accommodating design. The Palomar case history in the chiller section near the end of this report is a case in point.

Good idea, but not at this time. The first thing Kraft said regarding the viability of capacity improvements offered by inlet cooling was "It depends on how you get paid." The editors learned this first hand when they met with the engineering manager for a 2 × 1 F-class combined cycle equipped with evap coolers. Two plants nearby—one about 25 miles away, the other about 50—are equipped with chillers. One of the two converted from an evap cooler because of the value proposition.

The manager had a conversion plan ready for his plant and was just waiting for the opportunity to implement it. In this case, the owner assigned a low value for new capacity given other generating resources

Inlet cooling 101: TICA offers a refresher

Today's competitive generation business presents many challenges to owner/operators of GT-based powerplants. One is maximizing output and revenue, especially during the warm months when power prices typically are highest. Perhaps the most efficient way of boosting output is by cooling combustion air before it enters the compressor, says Dharam (Don) Punwani, president of Avalon Consulting Inc, Naperville, Ill, and executive director of the Turbine Inlet Cooling Association (TICA).

Recall that the power output of a GT is directly proportional to, and limited by, the mass of a volumetric flow rate of air. But while the volumetric capacity is fixed, the mass flow rate of air delivered to the compressor decreases as ambient temperature rises above the rated-capacity design point (so-called ISO conditions, 59F and sea level).

The actual impact of ambient air temperature on output depends on GT type, age, condition, etc. Information available at www.turbineinletcooling.org, the association's website, notes that aeroderivative engines are more sensitive to ambient temperature than frame machines.

"Turbine inlet cooling: An energy solution that's better for the environment, ratepayers, and plant owners," a white paper containing many charts and tables useful for go/no-go decision-making, notes that an increase in ambient from 59F to 90F can reduce the rated output of an aero with a 30:1 compression ratio by as much as 13%. By contrast, for an older frame with a 10:1 compression ratio the power loss would be 6%.

It is possible to increase the power output of a GT above its rated capacity by cooling inlet air below 59F. For the aero, delivering 50F air to the compressor would deliver 102.5% of rated output; for the frame, slightly less. But keep in mind that the generator also must be capable of operating above its rated output.

TICA's mission is to promote the development and exchange of knowledge related to GT inlet cooling, which in the group's words "provides a cost-effective, energy-efficient, and environmentally beneficial means to enhance power generation capacity and performance." A particularly valuable contribution of the website is its bibliography of publications on turbine inlet cooling dating back two decades. You can get there by clicking "Library & Links" on the horizontal toolbar at the top of the page.

Many companies offering products and services for inlet cooling are members of the association and they can be accessed via the website. You'll probably recognize the names of several companies and people in lineup of officers and board members below:

- President: Trevor Richter, VP, Stellar Energy Systems.
- Vice President: Annette Dwyer, regional sales manager, Munters Corp.
- Secretary: Russ Thompson, director of industrial business, Turbine Air Systems.
- Treasurer: Pat Graef, engineering and development manager, Munters Corp.

- Chairman, Board of Directors: Kurt Leibendorfer, senior VP, Stellar Energy Systems.
- Vice Chairman: John Kraft, president, Caldwell Energy Co.
- Companies not listed above and represented on the board: The Cool Solutions Company, Chicago Bridge & Iron Co, Natgun Corp, Baltimore Aircoil Co, Pasteris Energy Inc, Danfoss-Nessie High Pressure Water Systems, and Johnson Controls Inc.

in the area and its contract with the ISO. The conversion project is viewed positively by management, but not justifiable at this time. Swapping out the evap coolers for chillers here would be the capacity equivalent of adding an LM6000. You could think of the chillers as a virtual peaker.

But the motivation for doing the project could change. For example, should quick-response capacity be required to back up renewables, grid reliability rather than economics would be the reason to move forward. Delays in licensing new generating facilities to replace the existing plants being forced into retirement for environmental reasons might be another reason to implement the chiller solution.

Evap coolers

Virtually all evaporative coolers for GT inlet service are of the recirculating type and located downstream of the filtration system. The required water inventory is maintained in a sump at the bottom of the air inlet house (refer back to Fig 1). Water is pumped from the sump to a distribution header at the top of the cooler and it falls by gravity down through the media and back to the sump.

Air flows approximately perpendicular to the falling water and its *sensible* heat is transferred to the water, becoming *latent* heat as water evaporates. Resulting water vapor mixes with the air stream, carrying the latent heat along with it.

The dry-bulb temperature of the air is reduced because it gives up sensible heat. Wet-bulb temperature is not affected by the absorption of latent heat because water vapor enters the air at the wet-bulb temperature.

System chemistry is maintained in much the same way as it is for a wet cooling tower. Water specifications provided by the evap cooler supplier, plant chemist, and/or an outside consultant have, at a minimum, limits on turbidity, pH, hardness as calcium carbonate, and the concentration of sodium plus potassium. Makeup water is added to replace evaporation and blowdown losses.

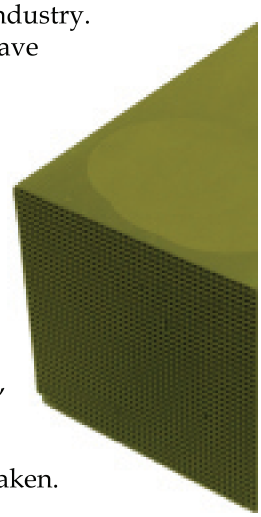
Makeup water specifications are important as well. It is important not to use straight demineralized water in evap coolers as you would in a fogging system. Such aggressive water softens the media and may damage the evap cooler framework, depending on the material used. Some plants use city water where available and of suitable quality, others might mix demineralized water with that from another source. Consult the media supplier to be sure you're going down the right path.

Spend quality time evaluating media alternatives both for new and existing systems; product offerings are always changing, usually for the better. Regarding the evap cooler now serving at your plant, recall that suppliers recommend changing media after three to five years of service to maintain top performance.

Several types of media for GT service are offered by Munters Corp, Ft Myers, Fla, considered by most users as the industry leader (www.munters.us).

The company promotes a special product for gas turbine applications, citing high efficiency, low pressure drop, low drift, and other attributes. It reportedly can be used in applications with average face velocities of up to 750 ft/min.

Finally, don't forget the drift eliminator. While water carryover from a properly designed, installed, operated, and maintained evap cooler should be negligible, critical parameters change over time and a drift eliminator immediately downstream of the media is necessary to protect the health of both the air inlet system and the compressor.



Fogging out, evap cooler in

Savvy powerplant managers generally know what works best for improving performance, safety, etc. But it often takes a long time to get management buy-in for ideas requiring significant expenditures. To be fair, executives must be careful how they spend the owners' money; good idea or not, return-on-investment criteria are unforgiving.

A case in point is a 7FA-powered 2 × 1 combined cycle located in the Mid-Atlantic region that began commercial operation in 2003 with the OEM's fogging system installed in each of the coated carbon-steel air inlet houses. The operations team leader for this facility told the editors the fogger was ineffective.

Thinking on the deck plates was that the relatively large droplets created by the nozzles were not evaporating as designers intended and the power boost with the fogger in service was marginal at best. So the system was not used. An editorial pause here: The names of the owner, plant, and operations team leader are not presented because there was insufficient time for corporate review.

Four years after COD, the business case for replacing the fogging system with an evap cooler was accepted. On the ideal day—85F and 45% relative humidity—the plant would produce an additional 15 MW; the improvement on any given day typically would be between 5 and 10 MW. Conservative calculations put the payback at around three years with the plant in cycling service. It is now running more hours, which translates to a faster return on the investment.

The project was bid competitively and Munters was selected. Contract labor installed the evap cooler in three months; however, the plant was shut down for only half that time. The 45-day outage had been planned for total plant overhaul. Work involved extending the air inlet house and ductwork modifications.

The plant owner was proactive at the design stage. Its highly experienced central engineering team reviewed evap-cooler best practices company-wide to assure the system installed would meet expectations. Maintainability was a key goal. Adequate space and platforms were built into the air inlet house to facilitate inspection, media replacement, and maintenance.

Plus, the fluid-handling skid was placed at ground level for easy access to system pumps, water sampling points, instrumentation, etc. Stainless steel was specified for all piping and pump impellers for long life. A new makeup system was installed for city water to replace the demin-water system required by the foggers. Tap-water quality is good at this location and can be used for evap-cooler service without pretreatment.

The first-year inspection and system flush were completed only a couple of weeks before the editors called the plant. No deficiencies were noted. A Munters representative was on hand for the inspection and compared the baseline water analysis with that done a year later. No significant change. The operations team leader praised the supplier's effort on the project and continuing customer service.

Replace old-style evap cooler, air inlet system

When Greenwood Energy Center (GEC) was built in the mid 1970s, long-distance road running was just coming into its own and there were more than just a few people participating in their basketball sneakers (Nike was incorporated in 1972). Today, you'd probably be hard pressed to find anyone in canvas tops running a marathon. The reason is obvious: High-tech shoes are critical for success.

The same is true in the generation business, which seems to grow more competitive by the day. Unless your facility has a great grandfathered grid deal, you're just not going to dispatch ahead of GTs with modern "front ends" capable of wringing the last few Btus out of their fuel.

The first of GEC's four simple-cycle, distillate-fired GE 7Bs began commercial operation in 1974, equipped with a rudimentary (by today's standards) ground-level evap cooler familiar to many readers (Fig 15). In 1996, the units were converted to dual-fuel.

Corrosion of the internal perforated galvanized-steel wrappers for the air inlet houses was virtually impossible to arrest and metal flakes and chunks were being ingested by the compressor. Maintenance procedure was to scrape off loose metal during the annual spring outage, sweep it up, and run another year. Tom Miller, who manages the Combustion Turbine Dept for Missouri-based owner Kansas City Power & Light Co (KCPL), said Greenwood personnel were filling a 55-gal drum with debris annually (sidebar).

Problems attributed to age and continued use of old technology included the following:

- Reduced peak output.
- Reduced efficiency.
- Compressor FOD (foreign object damage), requiring replacement of R1 blades.
- Snow blinding of barrier air filters during blizzards.

Bill Grace and his colleagues at Tulsa-based Braden Manufacturing LLC got their first glimpse at GEC's air inlet challenges in 2005. He recalled that the owner, Aquila at the time, was leaning towards taking the inlet air house's internal surfaces down to bare metal and coating with epoxy—a fast and inexpensive way to keep foreign material out of the compressor.

But a thorough engineering assessment revealed that the evap cooler and the inlet house had, practically speaking, reached end-of-life. The project then evolved from a repair job to a new intake system. Braden proposed replacing the ground level air inlet with an elevated system having Type 304 stainless steel internals. The company also suggested switching from barrier filters to a pulse-type filter house—this to prevent a unit trip on high delta p during a blizzard.

Greenwood Energy Center backgrounder

Kansas City Power & Light Co (KCPL), well known to long-time industry professionals, was reorganized under Great Plains Energy Inc in 2001, according to Ellen Flynn Giles, editor of the "UDI Directory of Electric Power Producers and Distributors," published annually by Platts, a division of the McGraw-Hill Companies Inc.

Holding company Great Plains acquired Aquila Inc's Missouri generating plants in July 2008 and combined KCPL's Missouri assets and Aquila's under KCP&L Greater Missouri Operations d/b/a KCP&L. Aquila had previously operated under the name UtiliCorp United Inc.

Tom Miller, a member of the 7EA Users Group steering committee, manages KCPL's Combustion Turbine Dept. He is responsible for a dozen 7Bs, 11 7EAs, three W501D5As, two FT4s, and one Frame 5 located in Kansas, Missouri, and Mississippi.

Miller's affiliation with Aquila began in the mid 2000s when he was construction manager for the South Harper Power Plant, a peaking facility in Peculiar, Mo, which began commercial operation in 2005. He was appointed head of Aquila's gas turbine assets in 2006 and transitioned to KCPL along with the assets he managed.

15. Ground-level air inlet supplied with Greenwood Energy Center's four 7B peakers were rudimentary by today's standards

Braden was awarded a turnkey contract to install new filter houses on the four Greenwood engines—one at a time. The upgrades were completed between 2006 and 2008 (Fig 17).

The proverbial "fly in the ointment" for this project: There was no compressed air available for pulsing the filters. Aquila didn't want the cost of a compressed air system added to the budget so engineers came up with the idea of tapping into the combustion wrapper. Certainly a viable idea, but that air was at about 750F and far too hot for cleaning filters.

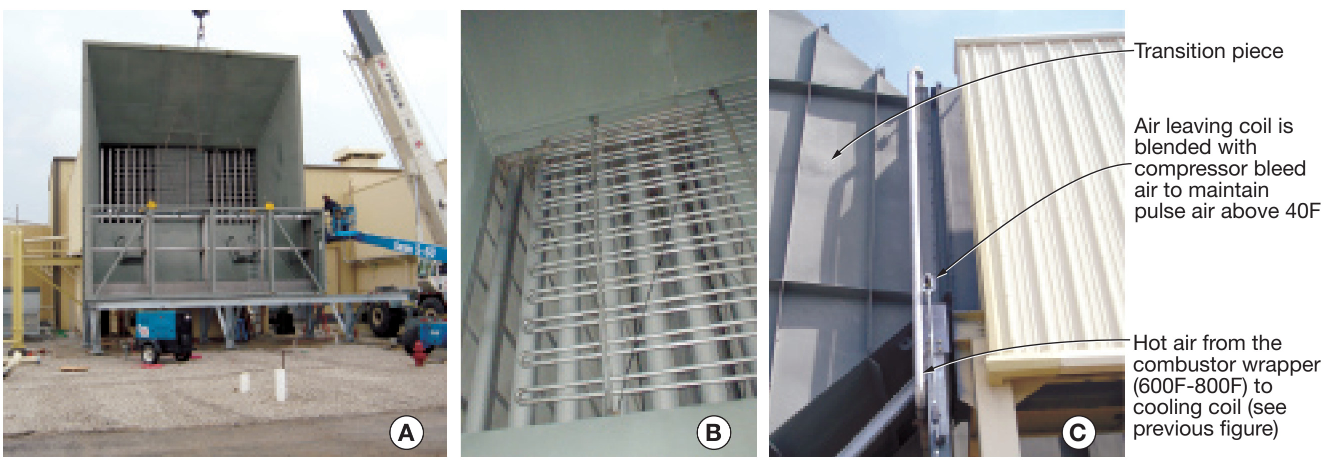
The solution: A heat exchanger, installed in the filter house, to cool pulse air to 95F (Fig 18a and 18b). That worked fine until winter, when the plant experienced freeze-up of the pulse-air system. The fix was to blend some compressor bleed air with the air leaving the heat-transfer coil to maintain the temperature of pulse air above 40F (Fig 18c).

Miller said payback on the retrofit was faster than expected because the turbines produced an additional 3 to 4 MW each with the new evap cooler; the units get capacity payments (Figs 19, 20). Taking air from the combustor case for pulse cleaning has virtually no economic impact. The ability to run through the horizontal snowstorms that often occur in this part of the country is very important.

The editors spoke to Miller via a hands-free phone while he drove to one of the company's plants in Mississippi, so the conversation went beyond retrofit of the air inlets. He said another major retrofit project for

16. Evap coolers were disintegrating and demolished

17. Transition-piece halves for the new air inlet system await installation



18. Heat exchanger (horizontal piping) cools compressor discharge air for pulsing service (A, B). Air leaving the coil is blended with compressor bleed air to maintain pulse air above 40F (C)

Greenwood was replacement of the OEM control system on each engine with Ovation®.

The controls solution from Pittsburgh-based Emerson Process Management, Power & Water Solutions was selected because the company had Ovation in its coal-fired plants and wanted to standardize on the platform to reduce costs. With Ovation the GTs are capable of running reliably on either gas or oil, or a mixture, and swapping fuels "on the fly."

Installation of demisters for the lube-oil system, plus upgrades to the generator-excitation, relay-protection, lube-oil-cooling, and fire-suppression systems also have been completed in the last few years.

The company's investments in its generation assets have paid dividends. Miller said that the fleet-wide starting reliability of its GTs was 98.6% last year. At GEC, he continued, the gas turbines can remain in service at loads down to about 4 MW—essentially spinning reserve. Operational flexibility is important when market conditions are such that "economy power" becomes available. Maintaining a reserve oil supply of 2 million gal onsite adds to the plant's flexibility.

Fogging

A viable inlet-cooling solution with widespread support

John Kraft replaced his TICA hat (see "Inlet cooling" intro, p 38) with one from Caldwell Energy when his conversation with the editors shifted to fogging and wet compression. In this space Caldwell competes with Mee Industries Inc, Monrovia, Calif, the gas-turbine OEMs, and Gas Turbine Efficiency, Orlando. Recall that GTE introduced a fogging system based on its extensive experience with high-pressure water technology for washing compressors about three years ago.

Kraft promoted the higher cooling efficiency of fogging compared to evap coolers and the fact that the former required no ongoing monitoring and control of recirculating water chemistry. Plus, the absence of a slowly increasing pressure drop across media meant fogging systems offered more consistent performance over their design lifetimes.

Fogging systems have been fighting a cloud of negative publicity in recent years as the leading frame OEM associated the failure of R0 blades on at least some of its F-class compressors with water droplets entrained in the air entering the machine. But judging from recent presentations at user-group meetings—the Combustion Turbine Operations Task Force (CTOTF) and D5-D5A Users in particular—the "fog" is starting to lift.

One example is the positive

19, 20. Filter module is prepared for a pick (left), fully assembled replacement air inlet is at right result Midland (Mich) Cogeneration Venture received from a fogging trial on one of its 12 Alstom 11N gas turbines installed nearly 20 years ago. MCV, one of the nation's largest cogen plants, supplies up to 1.35 million lb/hr of steam to Dow Chemical Co and produces up to 1560 MW.

A Mee fogging system was installed on one gas turbine in summer 2009 with the goal of boosting output so the new owners could strengthen their plant's balance sheet. Results validated expectations. Plan is to equip all 12 units with fogging systems by next summer.

Example 2. An update on several years of positive wet-compression experience during a CTOTF session reaffirmed the technology's value. Background: Mid-Atlantic plant with four dual-fuel, simple-cycle 7EAs; water injection for NO_x control. GTs began commercial operation in spring 1990, retrofitted with Caldwell foggers in 2001, and re-equipped by Caldwell for wet compression a few years later.

Operation is relatively simple. Foggers come on first. Wet compression kicks in when the wet-bulb temperature hits 50F and water injection is maintained at a constant 62 gpm. Capacity boost per engine ranges from 6 to 7 MW, depending on conditions. The existing demin system supplies water for both fogging and wet compression; a booster pump was added to accommodate the latter.

Example 3. The Siemens view of wet compression as presented to the D5-D5A Users was simply this: It can restore the drop in GT output attributed to high air-inlet temperature and it has the potential to make a huge step change in power output when needed. Furthermore, wet compression can achieve these objectives in a more cost-effective manner than can competing technologies.

The OEM said that depending on the engine and ambient conditions, the benefits include an increase in power output of from 10% to 20%, a heat-rate improvement of 1% to 2%, and more exhaust energy available for combined-cycle steam production.

Example 4. A user reported on work at his company to install fogging systems on two new simple-cycle 7FAs and on an existing unit (retrofit). Engineering calculations showed fogging beneficial above 60F; a 21 deg F differential is achieved at the compressor inlet on a 95F (dry bulb)/40% RH day.

The plant owner has extensive experience with inlet cooling and offered a few lessons learned/best practices for others considering fogging, including the following:

- Best results obtained with one booster pump and a variable-speed-drive supply pump in series to provide the 33 gpm (maximum) required for each 7FA. The 715-nozzle array is arranged in three zones. Previous systems had up to four pumps and nozzle arrays were arranged in six zones.
- Specify stainless-steel ductwork.
- Equip drains in the air inlet house with loop seals.
- Verify requirements, if any, for discharge of water drained from the bellmouth area.
- Check the bellmouth hourly for the presence of water carryover or streaking.
- Do routine preventive maintenance checks of the compressor inlet and take dental molds as recommended by the OEM. This user ran the fogging system about 250 hours on the existing 7FA equipped with standard R0 blades (the new machines had P-cut blades) and was approaching the OEM-recommended 8-mil erosion limit.

Note that the capacity gained from fogging is classified as "non-dependable power for dispatch" because the driver is ambient wet bulb temperature, over which the operator has no control. Plus, process control is limited by the use of a PLC-based system in this case; fogging is not controlled by the plant DCS.

Adding fogging capability to the existing engine required lengthening of the inlet ductwork. Original was of carbon steel; retrofit section, stainless steel and about 20 ft longer to provide additional residence time for evaporation.

Wanted: a fine mist

Sound engineering is important to success. Droplet size, in particular, must be tightly controlled. In addition, fluid system design and components must be first-rate. Root-cause analysis of fogging-system failures points most often to large droplets and to marginal pumps, valves, flowmeters, seals, location of recirc lines, etc.

Thomas Mee III, chairman and CEO, stresses that droplet size is the most critical factor in GT fogging and suggested 20-micron droplets as the optimum in a recent presentation. You want to avoid liquid-impaction erosion of GT airfoils, he said, adding that very large droplets are conducive to pitting and fractures.

On average, Mee continued, it takes a "good fog" about two seconds to evaporate. To achieve this goal, you should locate nozzles immediately downstream of the air inlet filters. However, in many GE 7FAs, nozzles are installed downstream of the silencers, leaving insufficient time for complete evaporation. The location of these nozzle arrays should be changed, he advised.

Mee Industries claims market leadership in the supply of fogging and wet compression systems with about 800 systems installed worldwide, including more than 80 F-series engines manufactured by GE.

One of Mee's messages is that fog droplets don't directly cause erosion. Rather, compressor suctioning of unatomized, flowing, and pooling water is potentially conducive to problematic wear and tear of critical parts. However, proper design of fogging and drain systems can prevent damage from these sources.

For more detail on fogging and wet compression, access www.combinedcyclejournal.com/archives.html, click 3Q/2008, click "To fog or not to fog: What is the answer?" on the cover; click Spring 2004, click "Recent experience indicates wet compression meets expectations when done correctly."

Chillers

TES maximizes energy send-out during periods of peak demand

Chillers traditionally have been the cooling system of choice for GT air inlets in climes where lower-cost evaporative alternatives were of marginal benefit—such as locales with prolonged periods of high humidity.

But across the broad TIC market, more than just a few owners of generating plants selling only kilowatt-hours considered the relatively high cost chillers a gamble. They would be betting there would be enough "hot" days with a sufficiently high grid price to pay off the bank note in timely fashion. The conservative business people who inhabit the executive suites of power companies typically are not the type to take unprotected bets on weather and grid price.

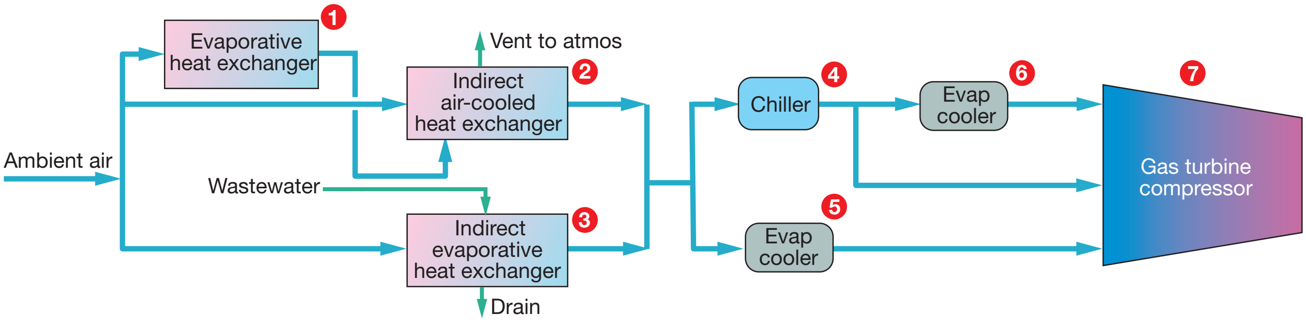
However, with the electric power industry in a period of significant change—fueled in large part by the low price of natural gas, climate-change concerns, and the need to integrate a rapidly increasing amount of power from intermittent renewables with conventional resources—new opportunities are emerging for chillers in locations where they would not have been considered seriously only a few years ago. Proof is in the number of chiller projects under consideration and completed recently.

The big advantage chilling has over evaporative cooling is independence from ambient conditions. A right-sized chiller assures the ability to produce nameplate output year-round. This, in turn, maximizes revenue generation for plants able to secure capacity and other ancillary services contracts from their ISOs.

Thermal energy storage (TES) adds to the value proposition of chillers. Tanks can be "charged" at night when electric demand is down and "discharged" when demand is highest—thereby maximizing power production and revenue.

The two F-class chiller-retrofit projects profiled in this section, Brazos Electric Power Cooperative Inc's Jack County Generation Facility and San Diego Gas & Electric Co's Palomar Energy Center, were selected for coverage because of the valuable insights they offer others contemplating changes to their inlet cooling systems or considering chillers for new projects.

Jack County illustrates how to approach the physical aspects of



21. Options for cooling turbine inlet air on GTs rated less than about 25 MW offered by Everest Sciences may increase net generation and improve net heat rate compared to traditional solutions

the project and provides details on how TES tanks are constructed. The Palomar case study is valuable for the perspective it provides on how to integrate a TES tank into plant operations for maximum flexibility and benefit.

The Palomar conversion was contracted to GE Energy, Atlanta, the Brazos project to Turbine Air Systems (TAS), Houston. Another major player in this sector of the air inlet cooling market is Stellar's Energy Systems Div, Jacksonville. One of that company's projects under review by the editors involves the relocation of grey-market chillers to a power project in the West and the integration of a TES tank to maximize flexibility. Another Stellar chiller project in editorial review, this one in Canada, offers know-how on how design and operate a glycol purge system to prevent freeze-up of the coils.

Finally, the section on optimizing turbine inlet cooling immediately below, offers new options for owner/operators of small GTs, which may involve chilling—or not. It illustrates the value of combining multiple heat-transfer devices into an integrated TIC system to maximize performance and return on investment.

Optimizing TIC

In the minds of most power professionals, GT inlet cooling can be accomplished in one of three ways: evap cooler, fogging system, or chiller. Selection often is made based on the lowest-cost alternative given the plant's ambient environment and power-supply contract.

In general, not much engineering time is expended on this phase of major power projects. Example: For a given plant, fogging may be nixed at the get-go by owners worried about the potential for water-droplet impingement on compressor blades, and chillers may be thought of simply as "too expensive." That would leave a wetted-media evaporative cooler as the "best fit" by default.

Perhaps there's not much an owner would gain by investing in more engineering on TIC, particularly in the merchant power sector where plants are "flipped" regularly. In such situations, low capital cost is critical to return on investment. Also, off-takers and contracts change over time which can alter the value proposition of inlet cooling. Chillers may make perfect sense if your plant qualifies for capacity payments, but what if you just sell energy?

Investment criteria are different when the GTs are installed to serve onsite load, such as at process plants and institutions. Low life-cycle cost, achieved through top performance and high capacity factor, typically is the goal in this segment of the generation business. Gas turbines for all but the largest refineries, chemical plants, and paper mills typically are rated less than about 25 MW, which opens up another option for TIC: Everest Sciences Corp's (Tulsa, Okla) highly engineered air inlet systems.

The company's factory-assembled and -tested modules incorporate filtration, cooling, and inlet noise control elements configured for specific site conditions. They can be installed over a weekend, or in less time, depending on the degree of preparation—for example, having electrical, water, and sewer connections available.

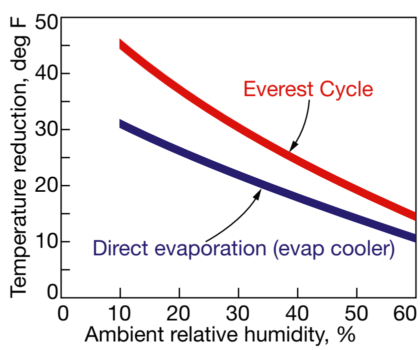
Two packaged TIC systems supplied by Everest have been operating successfully since early 2007, two more are scheduled for operation by early fall. The gas turbines at these installations all are A501K engines (manufactured by Allison and now part of the Rolls-Royce GT portfolio). The company's first LM2500 application is planned for early 2011.

You can look under the hood of an Everest TIC solution but you can't see the guts of the company's proprietary heat-transfer equipment. There's no smoke and mirrors here, the thermodynamics is "textbook." The company's engineers have integrated several components in a manner that significantly improves turbine performance through more effective heat transfer while reducing the amount of power required for TIC.

To understand what Everest has done in principle, follow the processes described in Fig 21. The company offers three general solutions: ECOCool™, ECOChill™, and Hydro-FlexCool™. Each begins with ambient air and ends with conditioned air being injected into the GT compressor.

In the ECOCool process, ambient air is cooled by evaporation in a high-tech crossflow heat exchanger (1 in the flow chart)—an entirely different device than the wetted-media evap coolers you are most familiar with (Fig 22). Air from (1) is used to cool ambient air for combustion in an air-cooled heat exchanger (2).

Key point: Combustion air flowing through (2) is cooled, and its density is increased, without adding moisture. Thus, for a given temperature reduction, mass flow is higher. More specifically, ECOCool reduces the enthalpy of the combustion air (removes heat energy), unlike conventional evaporative methods which cool air, but cannot change its enthalpy. This sensible cooling pro-



22. Everest cooling process is increasingly more attractive than direct evaporation as ambient relative humidity drops cess resembles a chilling cycle but it uses fans and pumps rather than large compressors.

Cool air leaving (2) next passes through a wetted-media evap cooler (5) before entering the compressor (7). Important to keep in mind when you dig into the company's literature at www.everestsciences.com is that the two-stage hybrid cooling process incorporating steps (1) and (2) is referred to as the Everest Cycle™. ECOCool is the name for the Everest Cycle coupled with the air-wash cooling step in (5).

Everest's Marcus Bastianen, PE/SE, sums up the benefits of ECOCool this way: "The hybrid process supplies air to the compressor at *less* than the ambient wet bulb using about the same amount of power required for conventional evaporative methods. It provides turbine inlet air at higher density than any competing evaporative technique."

ECOChill flow path is (1), (2), and (4), where the last is the chiller package. A final evap cooling step (5) may be added to optimize the offering for certain ambient conditions. ECOChill reaches target turbine inlet air temperatures with a chiller that is substantially smaller than one for a conventional refrigeration package because the former is less directly affected by ambient conditions. Air entering the chiller (4) is at a temperature significantly lower than ambient, some cooling already having been done by the Everest Cycle.

Comparing alternative GT air-inlet cooling strategies at 95F, 30% RH, sea level

	Gross power increase, kW		Net power increase, kW		Gross heat rate improvement, Btu/kWh		Net heat rate improvement, Btu/kWh	
Inlet cooling	GT1	GT2	GT1	GT2	GT1	GT2	GT1	GT2
None	Base case		Base case		Base case		Base case	
Evap cooler	7.4%	13.2%	7.3%	13.0%	1.1%	4.5%	1.1%	4.4%
ECOCool	9.9%	18.9%	9.8%	18.5%	1.4%	6.2%	1.3%	5.9%
Chiller	14.1%	29.5%	10.5%	23.9%	1.9%	8.8%	-1.3%	4.7%
ECOChill	14.2%	29.7%	12.0%	26.7%	1.9%	8.9%	Base	6.7%

Source: Everest Sciences Corp GT1=LM2500PC GT2=A501KH-7S
Assumptions: Direct evap is 85% effective; all parasitic loads (delta p, compressors, cooling towers, pumps, etc) are accounted for; analysis of GT1 performed using GE APPS Performance Prediction Program, analysis of GT2 performed using the Rolls-Royce Engine and Performance Prediction Program


Bastianen

The benefits, says Bastianen, are "lower chiller capital and operating costs, more *net* turbine power output, and higher *net* engine efficiency. ECOChill also offers users the flexibility to optimize their cooling processes as ambient and operating requirements change."

Once again, understanding the Everest lingo is important before dialing up the company's website: h^3 is the name Everest uses for its supplemental mechanical chilling process. ECOChill incorporates both the Everest Cycle and h^3.

Note that a separate cooling tower is not required to support chiller operation. Air discharged to atmosphere from the indirect heat exchanger (2) is sufficiently cool to condense the refrigerant. An induced-draft fan is integrated into the Everest package to drive the condensing process.

Hydro-FlexCool is a variant of the Everest Cycle. Its indirect evaporative heat exchanger (3) uses brackish or reclaimed water and air as the first step in TIC. A similar heat-transfer device has been used on large chiller-equipped frame GTs for condensing refrigerant rather than for cooling combustion air.

The Hydro-FlexCool option is ideally suited for gas turbines in arid, remote areas. Units in pipeline service come to mind because locally available brackish well water can be used as the cooling medium.

Advantages of water-to-air heat transfer over air-to-air include the following: simpler TIC system; less heat-transfer surface for a given duty; and evaporation of some plant wastewater (if this is the water source), thereby reducing the amount of wastewater that may have to be treated prior to discharge or stored in onsite evaporation ponds.

The density of combustion air leaving (3) can be increased by using a chiller (4), with or without the final evaporative cooling step, or by simply following the evap cooler route through heat exchanger (5).

Performance improvement offered by ECOChill (Everest Cycle + h^3) for LM2500 and A501KH-7S GTs is compared in the table to a conventional chiller, ECOCool, evap cooler, and base case with no TIC. Data show the significant improvement in net power and net heat rate offered by the Everest Sciences solution over a standard chiller for both engine types.

Reason is that the reduction in ambient air temperature achieved by the Everest Cycle becomes the starting point for the h^3 cycle. This means substantially less refrigeration is required to reach a target turbine air inlet temperature than for the chiller-only case. The Everest solution's much lower parasitic load means added revenue at lower cost for the plant owner.

If you want to see the results graphically, visit the Everest website and review the psychrometric charts. If your thermodynamics has gotten rusty over the years, you might want to review how to use psych charts before logging on. The bottom line, as the two case histories that follow attest, is that the Everest solutions deliver on their promise. All you really have to figure out is if the economics work for your plant.

Case history 1. The utilities manager for a food processing plant located in the California desert told the editors the facility's A501K was installed in 1986 and provided all the power required onsite. Engine operation is controlled to match plant demand. The unit operates in parallel with the grid, so if it is forced out of service, continuity of electrical supply is preserved. The cogeneration facility also has a single-pressure heat-recovery steam generator (HRSG).

The electrical generator is capable of 6 MW, but even with a Cheng Cycle upgrade, which uses steam injection for NO_x control and power boost, the GT wasn't capable of doing more than about 5.7 MW on a typical day. On hot days, when summertime temperatures often hit 110F-115F, the engine couldn't do better than about 5.2-5.3 MW.

The utilities manager the editors spoke with hired on nearly seven years ago. It didn't take him long to tire of the poor performance from the single-stage conventional evap cooler. By then, the cooler had been operating for almost 20 years and had seen better days; the plant runs about 8500 hours annually. Further deterioration in swamp-cooler performance and the GT might not be able to meet in-house demand on some days.

He investigated the conventional alternatives—new evap cooler, fogging, chiller—and what would later become Everest's ECOCool offering. Performance of the Everest TIC system installed was significantly better than the single-stage cooler with only a marginal increase in power consumption (Fig 23).

With the Everest upgrade, the engine can produce 5.6 MW on very hot days, an increase of 300 to 400 KW over that possible with the old evap cooler. Thus less steam is needed for power-boost service, saving on the cost of high-quality makeup water. Addition of the h^3 package wasn't considered because this plant already is producing all the power it needs with just the Everest Cycle front end.

Peltsch

Well water high in calcium and magnesium is used in the evaporative heat exchanger module (component 1 in Fig 21). The design is tolerant of bad water, the utilities manager said. Cycles of concentration are controlled by automatic blowdown based on water conductivity. Only real maintenance is to clean and flush the sump at the bottom of the TIC package quarterly.

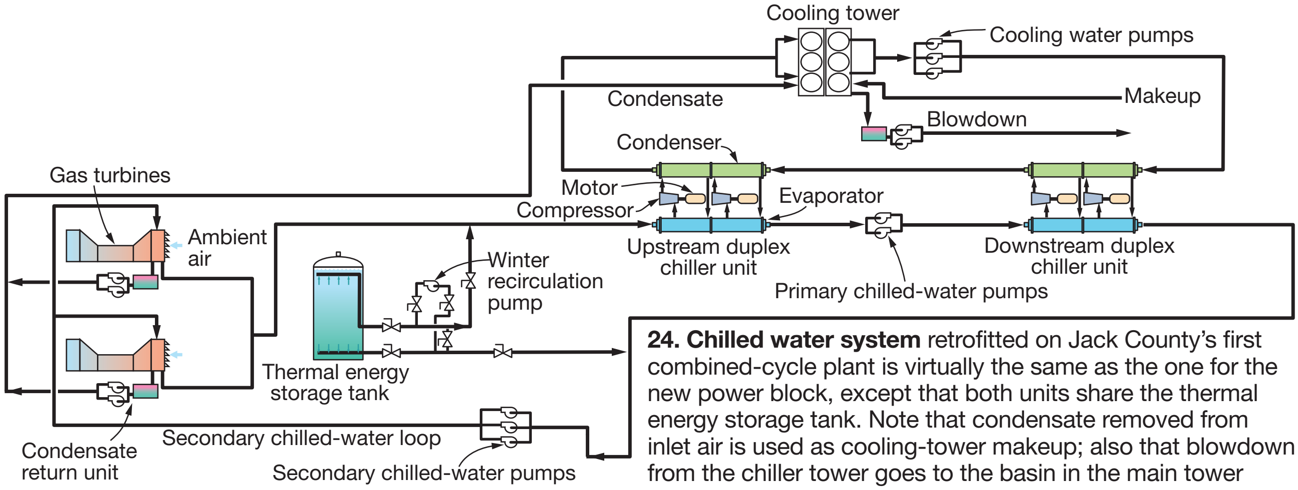
The utilities manager told the editors that the Everest equipment has met expectations and that the company always has shared improvements it has made to the equipment installed.

Case history 2. Chief Engineer Tom Peltsch, Sonoco Canada, Brantford, Ont, also shared his experience with the Everest Sciences equipment: Different climate and different operating paradigm, but the same positive results. Peltsch's powerplant provides all utilities to an ageless mill which now blends a variety of recycled cardboards to make the spiral wound paper used in the manufacture of containers for potato chips and other products.

A new generating plant installed in 1993 is powered by a gas-only Allison KB501 GT capable of producing 4 MW; mill requires 3 MW. Facility has a single-pressure, supplementary-fired HRSG and a gas/oil-fired 40,000-lb/hr packaged boiler to assure continuity of steam supply. Peltsch stressed the need for high reliability to satisfy mill commitments and to export power to the grid when financially viable.

The gas turbine was installed with only media filters on the front end. No cooling of inlet air would be required in Canada, or so engi-

23. Performance of the ECOCool TIC system installed at a food processing plant in the California desert was significantly better than a conventional evap cooler with only a small increase in power consumption



24. Chilled water system retrofitted on Jack County's first combined-cycle plant is virtually the same as the one for the new power block, except that both units share the thermal energy storage tank. Note that condensate removed from inlet air is used as cooling-tower makeup; also that blowdown from the chiller tower goes to the basin in the main tower

neers thought. After a summer with temperatures and humidity in the 90s the plant retrofitted an Everest Cycle + h^3 solution. Peltsch, who was not at the plant when the purchase decision was made, said there was little institutional knowledge on the matter.

The way the plant operates today testifies to the operational flexibility of the TIC system. The chief engineer said the Everest Cycle is turned on about May 1 and off by the end of October. Plant personnel continuously monitor ambient and turbine inlet conditions and bid into the hour-ahead market when there's money to be made.

Grid and gas prices are displayed in the control room, and with the aid of a weather station installed on the plant site and software to run revenue calculations, plant personnel can exploit an opportunity simply by turning on the h^3 (chiller) portion of the Everest TIC system.

Peltsch said the plant can dispatch to the grid 24/7, but the actual time it does depends on price. Operators minimize export and burn less gas when the grid price is low. He thought the chiller ran about 30% of the time during the May to October period.

Operators are continually fine-tuning operations to squeeze top performance from the plant, Peltsch continued. There are times a fan may be turned off because it's not needed and a few more pennies drop into the revenue basket. The GT compressor is online washed weekly to assure maximum efficiency.

Water used in the Everest Cycle comes from the city main. It is monitored for conductivity and bacteria to guide the continuous blowdown system. Peltsch said that the system requires very little maintenance but because a lot of dust is generated in the handling of bales of cardboard, the sump must be washed out on a weekly basis.

Texas chill

Cannon

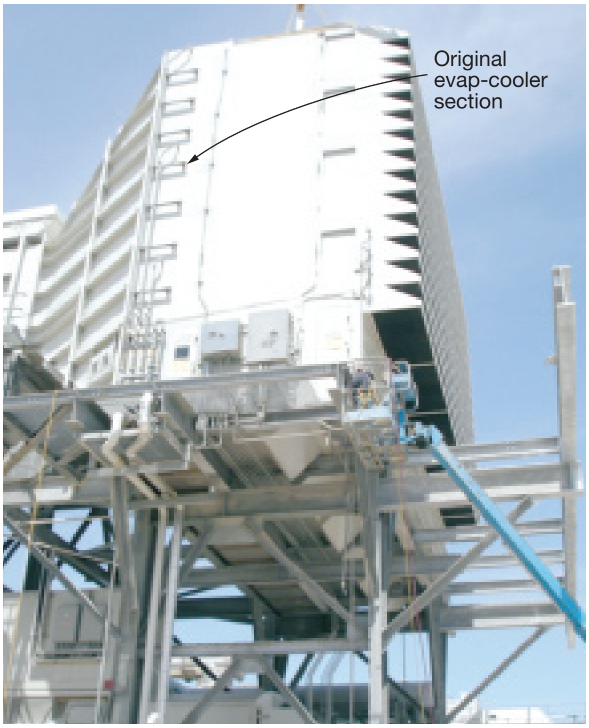
Brazos Electric Power Cooperative Inc is not a household name outside of Texas, but the company's Jack County Generation Facility is well known to industry insiders for its operations and maintenance know-how. In fact, Operations Superintendent Troy Cannon and Water Plant Supervisor Ronnie Johnson recently accepted one Best of the Best and two Best Practices Awards for the plant's innovative work in improving the performance of zero-liquid-discharge systems (see awards article elsewhere in this issue).

Readers may recall that the first 7FA-powered 2 × 1 combined cycle the cooperative installed at its Bridgeport site in 2005 was built in 17 months and for much less than the market price by judicious purchase of secondary-market equipment, which included evap coolers in the air inlet house. For details, access www.combinedcyclejournal.com/archives.html, click 4Q/2006, click Jack County on the issue cover.

Jack County rarely is offline. Bra-

25. Chiller package located below the six-cell cooling tower came in two modules and set on a concrete pad

26. Chillers were installed inside the modules prior to delivery onsite



27, 28. Air inlet house as originally installed is at the left, after removal at the right

Raines

Peterson

zos supplies power to its 16 member co-ops (primarily residential load) and one municipal system, and sells into the spot market when profitable and excess capacity is available (sidebar). Thus the ability to maximize generation is important—as are plant reliability and efficiency. Also important to Brazos: Minimize the risk of having to buy power at the market price to meet its commitments.

When Brazos began design of a second 2 × 1 for the Jack County site (now about 70% complete), it investigated an inlet-air chilling option to maximize output. The combined cycle was capable of producing 560 MW on a hot summer day (95F dry bulb, 75F wet bulb, 41% RH) with evap coolers; 605 MW was possible with a chiller capable of delivering 50F air to the compressor.

Further studies revealed that retrofitting a chiller on Unit 1 made economic sense and Brazos moved forward immediately. Turbine Air Systems (TAS), Houston, was selected to design and install the system (Fig 24). The project began Dec 1, 2008 and was complete by July 4 (Figs 25, 26).

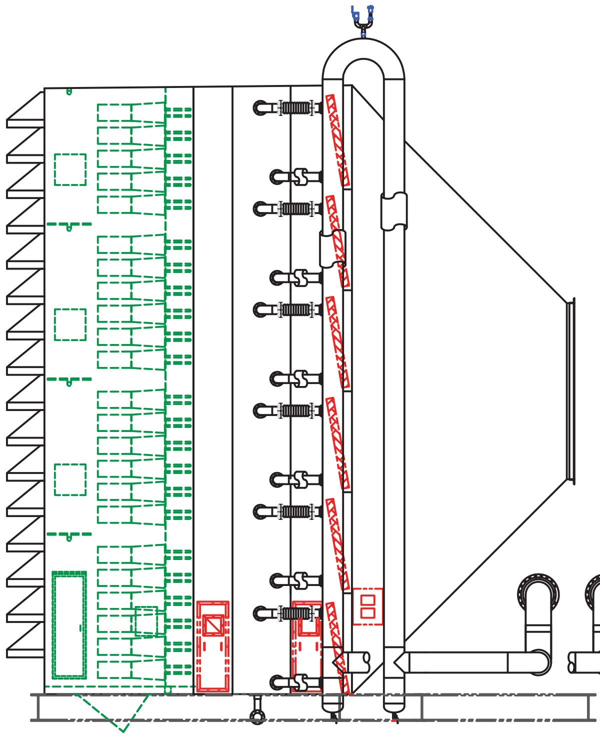
29. Original filter module is lifted into place after installation of the new chiller section and transition duct

A 6.1-million-gal thermal energy storage (TES) tank was installed later that summer and integrated into the chilled water system. The chiller package (two nominal 7300-ton duplex modules) is designed to operate independently or in tandem with the storage tank. The TES tank is designed to receive cold water from the chiller package during off-peak hours (charge cycle) and to supplement chiller output during peak hours (discharge cycle).

The system described in Fig 24 provides a total of 9100 gpm—a nominal 5900 gpm from the chiller, 3200 from storage—to the air-inlet coils on both gas turbines. Cannon, who was on the phone with the editors along with colleagues Carl Raines, operations supervisor, and Greg Peterson, shift supervisor, said the chilled water system was purposely undersized to minimize auxiliary power demand. The auxiliary power requirement is 5 MW.

On most summer days, the chiller runs around the clock although turbine inlet cooling is required for only 14 or 15 on-peak hours; remainder of the time is spent charging the TES tank, which can store up to 111,000 ton-hr of chilling capability. The chilled water systems for combined-cycle Block 1 and Block 2 are identical and share the TES tank.

Cannon said changing from an evap cooler to chiller was relatively



30, 31. New air inlet house, in drawing at left, photo at right, extends 17 ft beyond where the original inlet house ended

straight forward and was accomplished in three weeks during a scheduled outage in April 2009. The original air inlet house (Fig 27), supplied by Donaldson Company Inc, Minneapolis, was removed on the far side of the transition duct just ahead of the inlet-bleed-heat section and where the duct leading to the compressor inlet on a standard 7FA installation turns downward (Fig 28).

After the new chiller section and transition duct were installed, the original filter house—minus the evap cooler—was reinstalled (Fig 29). The mod extended the air inlet house by 17 ft over the generator. TAS subbed out modification of the inlet house to Braden Manufacturing LLC, Tulsa (Figs 30, 31). This work included construction of the chiller section using coils supplied by Aerofin Corp, Lynchburg, Va. Williams Industrial Service Group, Atlanta, a sister company of Braden's, performed the field work.

The piping manifolds at the air-inlet chilling coils are reverse-return for self-balancing, uniform flow distribution to all 14 coils serving each gas turbine under all operating conditions. Temperature control is via a modulating pneumatic butterfly valve in the return line from each coil.

TAS subcontracted the thermal energy storage tank to Natgun Corp, Wakefield, Mass. The company specializes in wire-wound concrete tanks (Fig 32).

Project began by clearing an access roadway around the tank perimeter and leveling the ground for the casting beds used to make wall and dome panels. Casting beds are placed around the tank to facilitate the lifting and placement of panels. Precasting panels onsite combines manufacturing plant quality with convenience. Each panel must pass compressive-strength tests before it is qualified for use.

Natgun's monolithically cast membrane floor is designed to flex in response to minor settlements. The entire tank floor is cast, vibrated, screeded, and final-finished in one continuous operation.

The company says an important feature of its tanks is the use of a watertight steel liner, or diaphragm, embedded in the tank wall. The vertically ribbed diaphragm is equipped to provide a mechanical lock within the concrete.

The construction process seals all spaces between adjacent panels, making the tank a continuous cylinder with an exterior steel shell and corrosion-resistant concrete interior wall. A water-stop encased in shotcrete creates a watertight connection between the wall and floor.

Natgun tanks are placed in permanent compression using a wire pretressing method in compliance with standards of the American Water Works Assn. Here's how this is done: A half inch coating of shotcrete is applied to the steel diaphragm and multiple layers of continuous wire are individually encased and bonded in the concrete.

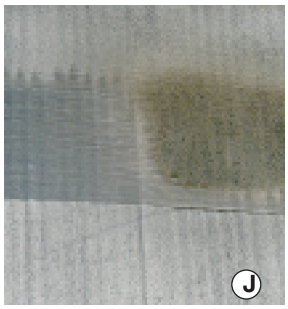
After the wire winding is complete, vertical screed wires are placed on 2-ft centers around the tank circumference to assure that the final coat is applied in uniform thickness. The shotcrete is screeded and given a final finish. A 3-in. layer of Styrofoam™ insulation is applied between the winding wire and the final exterior shotcrete application. The wall and dome receive a two-coat architectural treatment to provide a uniform color and to seal the

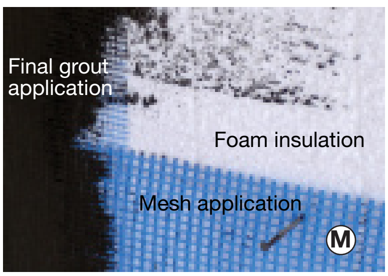
Brazos is Texas' largest G&T co-op

Brazos Electric Power Cooperative Inc, Waco, organized in 1941, was the first generation and transmission (G&T) co-op formed in Texas. It continues to be the largest G&T in the state with a service territory extending across 68 counties from the Texas Panhandle to Houston and a peak demand of about 2900 MW.

Brazos is the wholesale power supplier for 16 member/owner distribution co-ops and one municipal system. Each cooperative member is represented on the company's board of directors. Brazos' mission is simple: Generate, procure, and transmit power at the lowest possible cost.

The company owns four generating facilities: Jack County, described in the main text; Johnson County, a 270-MW 1 × 1 combined cycle also being upgraded with a mechanical chiller system; North Texas Plant, a 71-MW steam/electric station; and the R W Miller Generating Station, which can produce about 600 MW from its conventional steam and gas-turbine-based generating resources.





tank surface.

Winterization. Cannon and his operations colleagues said the biggest challenge posed by the chiller is winterization. Weather patterns in this area are such that you can have a serious cold snap (lower than 30F) and then rebound in a matter of hours to temperatures in the 70s or higher. Brazos can use the chillers during warm days to optimize its operation.

Plant personnel need a method to protect the coils in cold weather while allowing their operation within a few hours. Cannon thinks they'll use the chiller 40 to 50 days between November 1 and April 1, and that temperatures will be 80F or higher a third of that time.

Cannon, Raines, and Peterson figure glycol is probably part of the solution, but no definitive solution has been implemented. Currently, plant personnel winterize the chilled water system by draining the air-inlet chilling systems and cooling-tower basins of water and flushing a glycol/water mixture through the coils before sealing up the system until spring.

Long term, one option is to drain water from the chiller coils and chilled water circuit and fill that portion of the system with a mixture 25% glycol/75% water to provide freeze protection down to 15F; also, to add cooling-tower basin heaters. The glycol and basin heaters would permit wintertime operation of the chiller packages and the coils with the TES tank isolated from the system.

When the chilled water system is brought out of winter layup, the TES tank would be reconnected. Its water would push the glycol/water mixture out of the coils and chilled water piping and the fluids would mix in the TES tank.

A downside of this approach is that annual glycol costs could run as much as $100,000. Remember, too, that glycol in high concentrations inhibits heat transfer. How-

32. Construction of the thermal energy storage tank begins with site preparation and proceeds rapidly to foundation and pad work (A). Pouring of the floor is next (B), followed by erection of scaffolding to support the roof (C). Fabrication of wall (D) and roof (E) panels is done onsite. Once the concrete cured and quality-control checks are complete, tank assembly begins (F, G, H). Seals then are installed between the wall panels to form a continuous cylinder (I). Wire winding puts the tank in compression and gunite is applied (J, K). Insulation and final exterior preparation are final steps (L, M). Photo (N) shows distribution piping supported from the ceiling; (O) the final product

ever, it could take 30 years or so to build up the concentration of glycol in the TES tank to 30%, where it would be prudent to drain and flush the entire system.

Other options include these: (1) Heat water in the chilled water circuit using steam from an auxiliary boiler, and (2) Replace the water with glycol for the winter months and, in spring, drain the glycol to a storage tank for reuse.

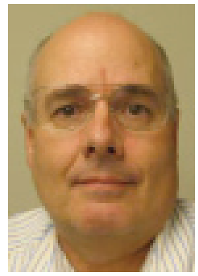
The last option seems most effective, but it would require a one-time investment of approximately $200,000 to implement. Meanwhile, protecting the cooling tower and other small piping systems also presents winterization challenges that could prevent a quick return to service.

Fine-tuning chiller operation to assure top performance

Palomar Energy Center, a 7FA-powered 2 × 1 combined cycle, owned and operated by San Diego Gas & Electric, a Sempra Energy utility, began commercial operation April 1, 2006 with evap coolers in the plant's air inlet houses. But they were not ideally suited for the Escondido (Calif) location or conducive to a strong balance sheet. For a backgrounder on Palomar, access www.combinedcyclejournal.com/archives.html, click 4Q/2006, click the plant name on the issue cover.

Simply put, with evap coolers, the full capacity of the plant was limited by ambient conditions. Palomar was capable of 565 MW, but on a hot, humid day could only produce 505 MW. GT capability changed day to day, hour to hour. The inability to accurately forecast capacity limited the plant's revenue, according to Dan Baerman, director of electric generation.

Baerman



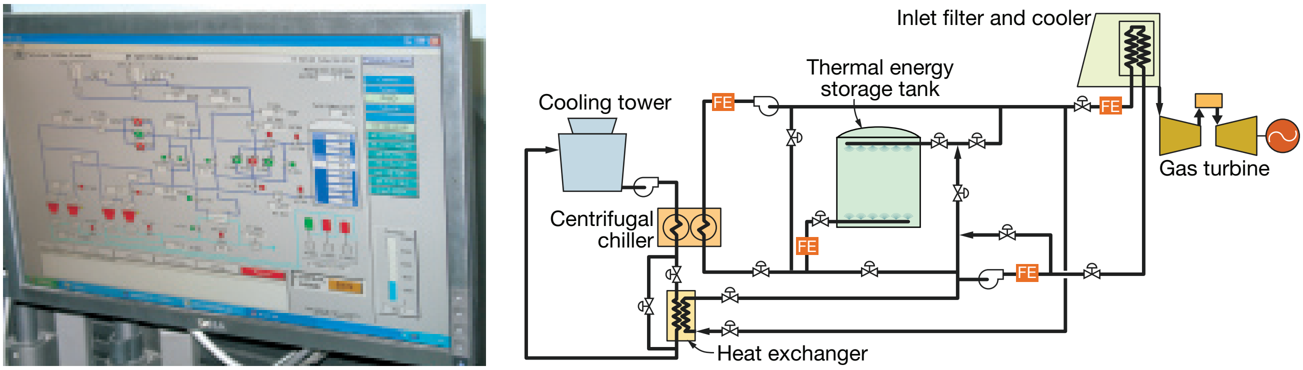
Martin

Plant Engineer Brian J Martin, PE, hired on at Palomar shortly after COD and he recalled that internal discussions on the value of a chiller retrofit already were under way. Martin added value to the dialog because he was party to a successful evap cooler-to-chiller conversion a couple of years earlier at a major California cogeneration plant.

The decision to retrofit chillers at Palomar was a big one for SDG&E because the plant was new and the company had just re-entered the generation business. Recall that California's major investor-owned utilities had been ordered by the state to divest of their generation assets several years earlier.

But economic analyses conducted collaboratively among engineering, marketing, and other stakeholders in the company made a compelling case for the conversion and the decision to move forward was made at the end of 2006. The utility wanted a system that would deliver 50F air to the GT.

GE Energy was selected as the turnkey supplier in competitive bidding. The utility already had a



33. Palomar's chiller plant is supervised by the GE Mark VIe DCS. It decides on the number of chillers to operate and when to turn them on and off. The chiller's PLC-based control system optimizes operation of the centrifugal refrigeration machines. Interactive operator screen is at left, simplified flow diagram at right

34. Variable-capacity chillers are arranged in redundant pairs. Total capability is 9000 tons of refrigeration

35. Chiller condenser receives water from the plant cooling-tower basin through the lower pipe, returns water to the tower via the upper pipe

36. Secondary chilled-water pumps supply the coils in the air inlet house

relationship with the OEM via a long-term service agreement and viewed the vendor as a company that understood what its customer needed. Another plus: The utility team favored GE's control system for its functionality.

The plant DCS has overall control of the chiller facility. For example, it decides on the number of chillers to operate and when to turn them on and off. The PLC controls provided for the chiller plant optimize operation of the centrifugal refrigeration machines. Automated operation, combined with highly flexible system design, assures the most efficient operating mode without excessive operator intervention.

37. Thermal energy storage tank of prestressed concrete construction holds 3.6 million gal of water. Outlet pipe is on the left, inlet on the right. Cold-water manifold at the bottom and warm water manifold at the top of the tank minimize turbulence to keep warm and cold water separated. Temperatures at various levels are available to the operator (see tank on right-hand side of screen in Fig 33)

Signing a contract early in 2007 and looking ahead to project completion was quick and easy. Interfacing with multiple state regulatory agencies and addressing the concerns of neighbors was time-consuming and challenging at times.

Annual emissions essentially "zeroed out," Martin said, but SDG&E still had to walk regulatory personnel through the project and the reasons for doing it. Conversion to chilling was considered a new source review because the plant would be producing power that it couldn't produce previously under certain ambient conditions. The air-quality review took a few months, but it went fairly smoothly, he added.

Review by the California Energy Commission was more involved, Martin continued. The CEC verified all the air emissions data with the San Diego County Air Quality Control District and also evaluated noise, visual impacts, water usage, etc. Then there was a public notice period.

To prevent noise from becoming an

38. Chilled-water sendout/return pipes exit/enter the chiller house. Pipe returning water from the chiller coils in the air inlet house is closest to the reader

39. Chilled-water supply pipe is closest to the reader

issue, the chillers were installed in a sound-attenuated building. Designers also took special care to insure that the chiller building, thermal energy storage (TES) tank, and piping would not be viewed a "visual impairment."

Water concerns were significant, and neighbors worried about the potential for a cooling tower plume. Interveners surfaced and fussed over this. Note that the existing cooling tower, which was slightly overdesigned, could accommodate the refrigeration condensers as well as the main steam condenser.

SDG&E talked over neighbor concerns with the tower manufacturer, SPX Cooling Technologies Inc, Overland Park, Kans, and the vendor produced what Martin called, "an elegant solution." Inlet heating of GT inlet air under certain ambient conditions reduces the tower's cooling load with no increase in water consumption. In fact, judicious use of inlet heating may reduce annual water consumption somewhat.

In addition, charging of the TES tank typically would be done at night when the heat load on the tower typically is close to or at the daily minimum (cooler ambient, off peak electric production) and there would be no visible plume. Another benefit of having a TES tank is that nighttime charging enables GT operation at a higher efficiency point than would be possible without it.

The CEC approved the project early in 2008, about a year after SGD&E and GE had signed the contract. Commissioning of the chilled water system was done in fall 2008 and the project was declared commercial by yearend. Martin said

40. Vertical manifold pipe serving the six chiller coils in each air inlet house is furthest from that structure. Chilled water enters each coil at the bottom, returns out the top via the inside manifold

the primary operational impact—installation of the coils in the air inlet house—was completed during the spring outage. Two other operational impacts—the chiller condenser circulating-water connection to the cooling tower, and medium-voltage electrical work (compressors and circ-water pumps are powered from the 4.16-kV bus)—were completed during later minor outages.

The central chiller plant, which has one supply and one return header, was designed "full-size" so to speak. It met system requirements without taking any credit for having a TES tank rated at 39,000 ton-hours. Four compressors, arranged in two redundant pairs, are capable of delivering the 9000 tons of refrigeration needed to assure 50F air to the GTs on a 97F day with 30% relative humidity.

Think of the chillers as an alternative to adding an LM6000 in terms of capacity, at a much lower heat rate—7000 Btu/kWh versus 10,000 for the peaker—and with no increase in emissions. Plus, they can reach maximum capability in about 10 minutes—table stakes in the grid world for fast-start capacity.

System arrangement. The chilled water system as it appears on the operator's screen with critical pressures, temperatures, flow rates, and equipment on/off indication is at the left in Fig 33, a simplified flow diagram to the right.

Three 50% primary pumps deliver chilled-water returning from the air inlet houses, or warm water from the top of the TES tank, to the centrifugal chillers. Cold water leaving the chillers is routed to the bottom of the TES tank or via the secondary pumps (also 3 x 50%) to the coils in the air inlet houses. The secondary chilled-water pumps also can take water from the top or bottom of the TES tank to supply the coils (Figs 34-40).

Three 50% auxiliary circulating pumps, installed in a small basin connected to the cooling-tower basin, deliver water to the chiller condensers. The small basin, protected from direct sunlight to prevent algae growth, was installed as part of the chiller-building construction project.

A plate-and-frame heat exchanger is installed in the circulating-water return line to the cooling tower. It recovers heat for warming compressor inlet air as a means for improving GT performance at low loads and in cool weather. Capturing heat from the circ-water return water reduces the thermal load on the cooling tower and conserves water.

Operating flexibility

System operating flexibility is critical to delivering top performance.

Baerman and his team drew on past experience of personnel and conducted an economic analysis with all viable options. Ultimately, station staff decided on eight modes of operation depending on ambient and other conditions. The details:

Mode 1. Turbine inlet cooling (TIC) using only the chiller. Electric chillers cool the water that absorbs heat from incoming combustion air. This mode of operation is used only when the thermal energy storage (TES) tank is out of service.

2. TIC using only water discharged from the TES tank. The centrifugal chillers are not operated, to conserve parasitic load. Chilled water stored in the TES tank is pumped directly to the GTs for inlet cooling. This is the most common daytime operating mode and the one that offers the best heat rate.

3. TIC with simultaneous chiller operation and TES tank discharge. This mode achieves maximum turbine inlet cooling capability and meets plant requirements on an extremely hot and humid day. It typically is used on the morning of an expected warm day to "save the tank."

4. TES tank charging. The centrifugal chillers charge the TES tank; gas-turbine inlets are neither cooled nor heated in this mode. Note that the tank can be charged without operating the GTs. This is, perhaps, the second most widely used option; it assures a "full" tank in terms of cooling capability.

5. Inlet heating/freeze protection. A heat exchanger is used to transfer heat from the circulating water system to the chilled-water loop. The warm water flows to the GT for inlet *heating*. This mode is used when (a) ambient temperatures approach freezing, regardless of GT operating status or load, and when (b) GTs are operating at part load with ambient temperature less than the circ water/cooling tower temperature. Inlet heating at part load (with IGVs at less than fully open) increases GT efficiency.

6. Inlet heating while TES charging. While charging the TES tank with the chillers, the chiller waste heat is transferred to the chilled water loop via a plate-and-frame heat exchanger. This takes the chiller load off the cooling tower (conserving water and fan power) while simultaneously providing extra warm inlet heating to the part-loaded GTs to improve turbine efficiency. This mode is not used as frequently as Mode 5.

7. Free heating and free TES charging. This mode takes advantage of warm days and cool nights. At night, warm TES tank water is circulated through the gas turbine to provide inlet heating while cooling the TES water. During the day, the cooled water is circulated to the gas turbine for inlet cooling, which heats the TES water. Ambient conditions conducive to this option do not occur frequently. However, on a really cool evening (35F-40F) you can extract the warmer water from the top of the tank and return it at a temperature consistent with that at the bottom of the tank.

8. Efficient TES charging. This mode is preferred when the ambient temperature is lower than the TES water temperature, but not cool enough for free TES charging. The warm water from the top of the TES tank is pumped through the turbine inlet coils for initial cooling. It is then pumped through the second chiller stage for final cooling before being returned to the bottom of the TES tank. The centrifugal chillers can be run at greatly reduced capacity in this mode. CCJ

P91 commands respect

Dean Motl called about the time of the spring equinox to say New Harquahala, the plant he manages, was inspecting P91 piping and found some off-spec material that he thought the industry might want to know about (sidebar).

Motl has benefited from collaboration with his peers in the 501G Users Group over the years and knows the value of sharing information. He mentioned soft pipe and the use of incorrect filler material on P91 welds as two issues identified. Also, that Maintenance Manager Chris Bates would be attending the upcoming HRSG User's Group meeting (held April 12-14 in Jacksonville) and suggested that the editors meet with him to dig into some of the details.

They did. Bates worked for a mechanical contractor when he learned first-hand about some of the problems associated with P91—such as pipe cracking. He added to knowledge acquired on the job by speaking with industry colleagues and by attending HRSG User's Group meetings. To refresh your memory, access www.combinedcyclejournal.com/archives.html, click 1Q/2005, click "Industry alert" on issue cover; click 2Q/2007, click HRSG User's Group, scroll to "Piping," p 4.

When Bates transitioned from the mechanical contractor to New Harquahala a couple of years ago, one of the first things he did was ask questions concerning the paper trail on the plant's P91. His experience suggested materials specs, heat-treatment reports, weld inspection reports, etc, often went missing. Another thing he had learned: A significant level of expertise was required to plan and conduct the proper metallurgical inspections and to analyze the data collected.

Motl

Bates

Some critical data needed to certify New Harquahala's P91 piping as "meets today's industry quality standards" was not available—just as Bates had thought. He championed the idea of conducting a comprehensive inspection program with the hope of recertifying the material installed.

Gaining experience in P91 inspection and analysis, and in developing inspection and testing guidelines, also would help others. NAES Corp, Issaquah, Wash, the plant's contract operator and Bates' employer, had perhaps another hundred plants under management that might also benefit from the lessons learned.

Due diligence of possible contractors for planning and conducting the requisite inspections and for analyzing the data pointed to Structural Integrity Associates Inc (SI, San Jose, Calif) as a company with significant and relevant P91 experience. SI was on NAES's preferred vendor list and had done work at other plants the company manages so the decision to hire this consultant was relatively easy.

The editors also were familiar with SI's work in the field having attended one of the company's P91 workshops a couple of years ago. However, just how the firm acquired its expertise was an unknown until Fred DeGrooth and Steve Gressler, both of whom were involved in the New Harquahala project, offered the following backgrounder:

SI, a leading participant in EPRI (Electric Power Research Institute, Palo Alto, Calif) and international research efforts on P91, first identified material issues in 2000. One of SI's clients was building a combined-cycle plant and had some questions regarding heat-treatment specifications. Inspection revealed off-spec material.

1. Knowing where to take hardness measurements is an art. This 20-in.-diam 90-deg elbow in New Harquahala's HP steam system had "chronic" softness. Several points show hardness readings below 190 HB, the suggested lower limit for P91

New Harquahala

That's not a tongue-twister, merely a four-syllable plant name pronounced just the way it's spelled. New Harquahala Generating Co LLC is located about 60 miles west of Phoenix in Tonopah. It is equipped with three natural-gas-fired 1 × 1 combined cycles power by Siemens Energy SGT6-6000G engines (formerly know as W501Gs). The plant, operated by NAES Corp, Issaquah, Wash, is managed by Dean Motl.

Another client, having suffered a fire at one of its plants, called in SI to see if the heat had adversely impacted the material. The firm again found off-spec material, but determined that the P91 softness (an indicator of substandard material) could not have been caused by the fire.

Not accepting the two findings of softness "a coincidence," metallurgists immediately began developing an aggressive program to learn more about P91's behavior and how to reliably and accurately identify material of poor quality. SI moved quickly to find any problems before warranties ran out.

Gressler said that an initial step in current P91 evaluation programs is to screen out the bad material. Specifically, eliminate the outliers—material that clearly has diminished properties. The current range of acceptable hardness for parent metal is 190 to 280 HB (Hardness, Brinell), he added, noting that the upper and lower limits have evolved over time. Weld hardness can be higher.

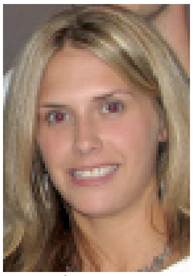
Hardness is only used for screening, Gressler continued. "Hardness by itself doesn't determine material health, it's merely an indicator." Hardness doesn't tell you when you're going to have a problem and in that regard it's much like your cholesterol level.

A baseline inspection is all-important. You must have current material properties to determine both a corrective course of action and how quickly the work must be done. But inspection is not as easy as it might appear.

Knowing where to take the hardness measurements is an art, Gressler said, and data collection an iterative process. If you find some soft material, he added, you have to go back and take more measurements to see how large the affected area is, and how deep (Fig 1). Sometimes the softness is just at the surface in the decarburized layer and the base material is satisfactory.

New Harquahala's strategy was to conduct its baseline inspection over a five-year period so most of the work could be done during regular planned outages and the project would have a manageable impact on the plant's balance sheet. Bates said inspections focus on the high-pressure (HP) steam system from the heat-recovery steam generator to the steam turbine, and the hot-reheat (HRH) system from the HRSG reheater outlet to the inlet of the intermediate-pressure (IP) turbine section. All available drawings and materials and fabrication records for those systems were retrieved by plant personnel before SI began work.

An important step in the process was to prioritize which welds, fittings, and sections of pipe would be checked first, second, third, etc. SI prioritizes inspections based on a detailed review of plant design, procurement, and erection, using a method similar to the company's Vindex™ method developed for lower-alloy piping. The Vulnerability Index is a semi-quantitative damage-ranking methodology that considers both inspection history and component characteristics. The damage consequences considered in Vindex methodology consist of safety and/or lost generation.



Armstrong

First year's work. Inspections of New Harquahala piping spools and girth welds assigned Priority I status are scheduled for completion in 2010. Unit 2 was inspected early this year during a 45-day outage that included major compressor work. Next came Unit 1; work was completed during a 15-day outage scheduled for other purposes.

Some inspections have been done on Unit 3; remainder should be completed by year-end. Only about 10% of the piping in the HP and HRH systems was classified Priority I. Priority II and III each total about 30% of the P91; Priority IV represents the remainder.

Bates told the editors that the demanding Unit 2 outage absorbed all of the plant's available manpower, leaving no one to work alongside SI on the metallurgical evaluation.

NAES considers the central engineering support it provides plant O&M teams a competitive advantage in business dealings. For the New Harquahala P91 evaluation, the company assigned Nancy Armstrong, a staff metallurgist located at corporate headquarters, to the plant for several weeks. That was an important move.

One reason: Armstrong's experience. She has a solid background in the design of piping and pipe-support systems from her days as a component engineer at Ontario Power Generation Inc's Pickering Nuclear Generating Station.

Another: Some inspection results were surprising and the knowledge Armstrong gained on the project enabled her to develop a set of best-practices guidelines on P91 inspection and testing to assist other plants in the NAES family.

Unit 2, Phase I results

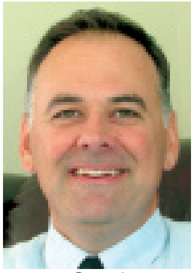
Positive material identification (PMI) and hardness tests were conducted on four HP steam and four HRH components and their respective girth welds. Low hardness values—approximately 170 HB—were found on two 90-deg bends and one tee on the HRH line (Fig 2). These anomalies suggested that in-depth testing was warranted.

Metallurgical replicas were taken at representative test points and sent to SI's Material Science Center in Austin, Tex. If analysis confirms

2. Technician takes hardness readings on main steam pipe

3. Weld joint was found with 1.25Chrome filler material instead of the required 9Chrome

4, 5. Off-spec weld was removed with a clamshell pipe cutter (left) and the joint prepped for rewelding after verifying that no cracks were present in the material (right)


Gressler


DeGrooth

the suspicion of metallurgists that the material has an improper microstructure—and by extension, reduced creep strength—further evaluation will be required.

This might include one or more of the following:

- Determine the depth of material softening by plug sampling and metallurgical analysis.
- Estimate future serviceability through engineering analysis conducted using conservative material properties in combination with actual design and operating conditions.
- Install high-temperature strain gauges to monitor strain accumulation. This would be done in combination with engineering analysis for life prediction.
- Replace the component.

DeGrooth and Gressler paused to stress the importance of proper microstructure in minimizing creep damage. They said that all materials suffer from creep in high-temperature environments, adding that creep-induced cracking of P91 has been found at several plants in the US and UK.

P91 accumulates creep and fatigue damage much like the older P22, which is more familiar to powerplant owner/operators. But because P91 piping has a thinner wall than P22 for equivalent service conditions it is less prone to thermal strains caused by temperature variations over time. Gressler said that an operating temperature of only 20 deg F above the design point can reduce material life by half.

Unexpected surprise

You may wonder why PMI testing is necessary. Perhaps you even think that it's make-work for the consulting team. Consider this: Even if when all necessary drawings and materials certifications are available, do you really know if all the inspections that should have been done during construction (both at fabrication shops and in the field) actually were done, and how well they were done? Paranoia? Possibly. But lives may be at risk so you can't afford to skip PMI in the inspection process.

SI's work at New Harquahala uncovered low-alloy filler material in a critical weld in Unit 2's HP steam system (Fig 3). Then metallurgists found the same material in the same weld on both Units 1 and 3. Clearly, this was unexpected and of great concern. You can ask yourself, "Why did this happen? How did this happen?" But you'll probably never know, and the only question that really matters is "How can we correct the situation, and how quickly must we react?"

Background. PMI revealed that the circumferential girth weld joining the P91transition piece in the main steam line to the P91 steam-turbine stop valve was fabricated using 1.25Chrome material (P91 is 9Chrome). Decision: Replace the weld (Figs 4, 5).

The weld repair was not straight-forward because of the difficult location and the different sources of P91 material for the transition piece and the valve body. Regarding the latter, the valve, fabricated to European code standards, was tempered at a lower temperature than that used to temper P91 piping.

Documentation provided by Siemens Energy, which supplied the steam turbines as well as the gas turbines, indicated that for welds requiring heat treatment, the temperature range must be between 9 and 45 deg F *below* the last tempering temperature of the valve body: 1346F.

Industry experience indicates that exceeding the temperature can damage the base material during postweld heat treatment (PWHT). However, the Siemens requirement is not consistent with guidelines presented in Section I of the 2009b *ASME Boiler and Pressure Vessel Code,* table PW-39, which recommends 1375F. But it does conform to the current version of ASME's B31.1 Power Piping Code.

SI's position was that the lower PWHT was acceptable but would require a significantly longer time at that temperature than it would at the higher temperature—specifically nine and a half hours at 1346F versus four hours at 1375F. Both the consultant and the plant thought this a reasonable compromise for achieving the required hardness while satisfying the Siemens request.

Hardness tests indicated a successful weld repair. All Brinell values were between 180 and 280 and full transformation to the desired tempered martensitic structure was achieved. More welcome news: There was no damage to the valve. Some softening of the pipe base metal occurred, mostly unavoidable given the extended PWHT soak time.

6. P91 pipe is prepped prior to taking hardness measurements

What might have been.

Had the out-of-spec weld not been identified and repaired in a timely manner, failure was highly likely. What often occurs over time when materials of different chromium content are welded together: Cracks initiate and propagate through the carbon-depleted zone that forms during the welding process.

P91 guidelines

The "P91 Inspection and Testing Guidelines" prepared by Armstrong, based in large part on the New Harquahala experience, provides personnel at other plants managed by NAES a foundation in best practices for evaluating the metallurgical condition of material installed and for correcting deficiencies.

The process suggested in the guidelines essentially follows the same path as that described above for New Harquahala:

- Gather materials tracking reports and inspection records.
- Collect records of material processing, induction bending, PWHT, etc.
- Conduct surveys of critical piping systems—including supports.
- Review stress analyses done by original designers
- Map HP and HRH steam systems and identify all components.
- Prioritize inspections and results.
- Identify inspection locations.

Next, Armstrong offered background on the approach generally taken when conducting P91 evaluations in the field—this to help plant personnel evaluate procedures proposed by companies bidding on inspection work. Three big caution flags before work begins:

1. Never conduct tests when a unit is running.

2. Make sure the steam supply system is isolated according to LOTO procedures.

3. Do not test piping when its temperature exceeds 100F and/or line pressure is greater than 2 psig.

The basic inspection approach:

- Verify material composition using x-ray fluorescence spectrometry.
- Map pipe-wall thickness prior to and following surface preparation at hardness test sites, both to confirm material removal to clean metal and that minimum wall thickness has been maintained.
- Map out locations for hardness measurements. They should extend around the pipe circumference at the 3, 6, 9, and 12 o'clock positions on both welds and base metal.
- Prepare locations by grinding only after a hot work permit is in place. A light disk grind of 5 mils or less generally is recommended, followed by use of a flapper wheel 120 grit (Fig 6).
- Test for hardness using the ultrasonic contact impedance method with supplemental testing using pin-Brinell.
- Accept hardness results in the acceptable range of 190 to 280 HB. If hardness is below 190 HB, disk grind 20 mils using a flapper wheel 120 grit to verify that the base material is soft and the hardness reading is not being influenced by surface scale. If the hardness is still low, and there is sufficient remaining wall to confirm that the material would not be compromised, examine further using replication or core or boat sample.
- Use metallurgical replication to examine microstructure at suspect locations.
- Site report should document the results and provide recommendations regarding any corrective action or additional testing.
- Nondestructive examination of the highest-priority weld location may include one or more of these methods: wet fluorescent magnetic particle, linear phased-array ultrasonics, and replication.

Once all the inspection data are collected and analyzed, Armstrong suggested development of a detailed plan both for future inspections and evaluations and for needed piping modifications. Other sections of the report detailed requirements and procedures for heat treatment, welding, and record-keeping. CCJ

Options for monitoring generator condition and their limitations

Clyde V Maughan, Maughan Generator Consultants

Editor's note: Predictive analytics (PA) generally gets favorable reviews across the electric-power industry as an effective means for backing up shrinking powerplant operating staffs. Monitoring and diagnostic (M&D) centers that suck data from plant historians, analyze the information, and advise when problems loom are a "hot" service offering today.

However, before signing a contract you'll probably want to understand exactly what kinds of damage PA can identify—a cracked turbine blade, for example—and to what degree it is capable of "protecting" different types of equipment. One success story: PA has saved several owners from significant losses by warning operations staffs of impending failure of gas-turbine hot-section parts.

But how effective is PA's early-warning system for generators? While trends in coolant and rotor temperatures are somewhat helpful, most of the information experts need to assess a generator's health is not captured by the plant historian and generally not available for use in PA.

This means it's up to plant personnel, perhaps with expert help, to develop the most effective program possible for generator condition monitoring. You'll find Clyde Maughan's article a helpful guide in this effort—in particular for its frank assessment of current diagnostic methods.

Generator stators and fields historically have been monitored by relatively unsophisticated instrumentation to detect over-current, under-current, general over-temperature conditions, local overheating, abnormal vibration, incorrect pressures, field ground, phase current unbalance, stator single ground, and stator line-to-line fault.

But standard instruments do not detect some common generator failure modes. To increase the likelihood of identifying deterioration, consider adding advanced instrumentation—such as a generator-condition pyrolysis monitor, partial-discharge measurement systems, field turn short detector, end-winding and slot-bar vibration monitoring devices, gas-discharge-rate monitors on liquid-cooled stator windings, etc.

These devices typically are affordable if they can be installed during a major outage.

Advanced monitoring devices provide an additional measure of protection against important failure mechanisms—such as slot discharge, some forms of stator-bar and end-winding vibration, field turn shorts, some additional forms of localized overheating, stator insulation delamination or cracks, stator over-flux, and some forms of series/phase joint deterioration.

Limitations. However, even with the best monitoring systems installed, generators remain with little or no detection capability for some common and serious deterioration and failure mechanisms, such as the following:

- Stator-bar vibration without partial discharge (PD) or vibration sparking.
- Stator-bar strand-header water leaks.
- Developing cracks in stator-bar connections.
- Field coil/turn distortion.
- Developing field turn cracks.
- Retaining-ring corrosion and cracking.
- Forging cracks.

Unfortunately, instrumentation

1. A well-programmed DCS can provide plant operators valuable guidance regarding corrective actions in the event of an alarm or other abnormal output from available instrumentation

capable of detecting problems such as these is not yet on the horizon. This means that several of the most serious failure mechanisms cannot be monitored and that performing generator maintenance on a predictive basis—one based on instrument readings—will continue to be imprecise and uncertain.

But the situation can be mitigated somewhat by optimum use of the capabilities of a modern distributed control system (Fig 1). A well-programmed DCS can provide operators valuable guidance regarding corrective actions in the event of an alarm or abnormal output from the available instrumentation. This capability is particularly valuable given that generators typically alarm infrequently on several of the devices—for example, stator-winding RTDs and TCs, and generator condition monitor.

The following section describes the types of generator monitoring equipment available to you and summarizes the value proposition. It is divided into mechanical, thermal, electrical, and PD monitoring equipment.

Mechanical

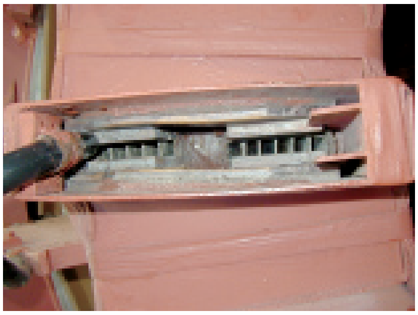
Field vibration. To balance and properly monitor the mechanical performance of a field, vibration levels associated with its rotation must be measured accurately. This can be accomplished by installing shaft-riding or proximity vibration detectors directly on the journals. They are vital for assessing problems such as vibration related to field temperature and/or current. If both vibration magnitude and angle are measured, you can determine the length and angle of a "thermal vector" and identify the optimum corrective action.

Stator end-winding vibration. Generators larger than about 100 MW have a history of in-service failures caused by excessive stator end-winding vibration. Problems can result from both general and locally resonant vibrations. Vibration detectors now available can be mounted safely on stator end windings (Fig 2). They are relatively easy to install but because they still are relatively new, some technical assistance may be necessary.

These detectors allow for the first time routine and accurate measurement of end-winding vibration levels. This is an important advancement because heretofore end-winding vibration has been a major cause of generator forced outages. The instrumentation allows trending of general and local end-winding vibrations

VibroSystM Inc

2. Stator end-winding vibration sensor pickup, relatively easy to install, helps prevent generator forced outages



3. Stator winding RTDs and TCs can alert on significant change in winding copper temperature. Hose (arrow) picks up discharge air flow from stator bar and directs it to an RTD

to help determine when an outage should be scheduled.

Thermal

Generator-condition pyrolysis monitors identify local and general sources of excess heat. With the addition of temperature-sensitive paints, there's a general indication as to where the problem may be occurring.

Early monitors were vulnerable to malfunction, particularly if not maintained in good condition. Such malfunctions were conducive to false alarms. Excessive false alarms at some plants caused operators to disregard alarms altogether, which was a mistake in at least a few instances where generators failed in service because alarms were ignored.

However, current models—those produced after about 1990—are more reliable and can be a valuable monitoring device. These instruments are offered by Environment One Corp, Niskayuna, NY, and General Electric Co.

Stator-winding RTDs and TCs. There's a strong inclination for plant personnel to operate generators based on measured winding temperatures. But the information obtained from the standard resistance temperature detector (RTD) or thermocouple (TC) is only peripherally related to the actual temperature of the winding copper.

Reason is that these devices typically are embedded in the slot where they read a temperature average of surrounding media: tooth iron, cooling gas, and copper (through a thermal insulation blanket). This "average" temperature typically is 20 to 30 deg C lower than the actual temperature of winding copper.

On generators with gas-cooled stator bars, OEMs may locate sensors to read the outlet gas temperature from a few stator bars—typically one TC per half-phase, or a total of six. These TCs are valuable because they can immediately identify a failed bar connection in a typical two-parallel-circuit bar structure.

For water-cooled windings, TCs typically are located in the water discharge circuit from each bar or pair of bars. However, in many designs, a common outlet is used for top and bottom bars. If this is the arrangement on your generator, be aware that if one of the bars is starved of coolant flow, or if no flow exists, the TC may not be sensitive to that condition.

Furthermore, on some designs the connection rings are cooled in series with selected stator bars, and it is important to separate the TCs into the two comparable groups when evaluating readings. The net result: It is difficult to determine if the generator is malfunctioning, and predicting winding maintenance requirements becomes challenging.

Electrical

Field grounds. Both single and double field-ground conditions can be hazardous to both personnel and equipment, which is why industry standards recommend that the unit be brought offline in the event of a field-ground alarm. Industry focus is on the hazard associated with a double ground in a field winding.

But remember that single grounds frequently result from a break in the copper winding. In all such cases, the ground likely is associated with arc burning of the field forgings. This damage can be rapid and severe (Fig 4). The field-ground device offers no information as to where the ground might be within the field, or external to the field.

Field inter-turn short detec-

tion (flux probe). Field inter-turn short-circuit detection equipment has been available for many years, but only relatively recently has this device come into extensive use. The field must be removed to install a permanent probe (Fig 5) and the field slot wedges under the probe region must be non-magnetic in order to obtain a reading on the slot. Ordinarily, the latter is not a problem.

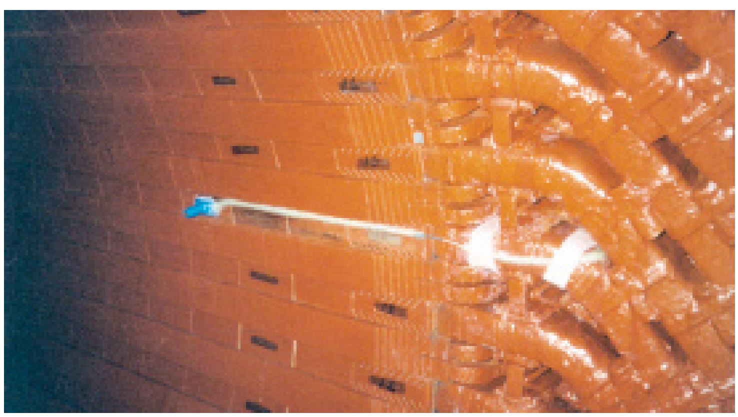
The flux probe is highly reliable, with little exposure to error or ambiguous readings. It can determine the precise coil in which the short exists, and can detect a single-turn short in a 30-turn coil. However, it offers no information as to the axial or radial position of a short. Flux probes are available from all major OEMs and Generatortech Inc, Schenectady, NY.

Although isolated shorted field turns are undesirable, their existence is not necessarily a serious concern. If generator operation is satisfactory—that is, vibration levels are within spec and field current is not excessive—an immediate outage to perform the complicated and costly repair may not be warranted. In this situation, it may be practical to plan for a short-turn investigation and repair at the next scheduled outage.

Collector/brushholder rigging. There's no direct monitoring of collector performance, other than measuring cooling-air temperatures in and out. Significant brush arcing will cause erratic readings on field temperature instrumentation, thus providing an indirect indication of possible trouble. Collector performance must be monitored by direct daily observation (access www.combinedcyclejournal.com/archives.html, click 1Q/2010, click "Maintaining carbon-brush collectors" on cover.

Because ongoing maintenance is

4. Severe burning on retaining-ring ID was caused by a single ground in the field winding



5. Flux probe is highly reliable, has little exposure to error or ambiguous readings. It can determine the precise coil where a short exists needed to keep collectors functioning properly, they are a major cause of generator forced outages. There are particular concerns on small machines without the insulated cartridge brushholders that allow safe and easy online brush maintenance.

There is a special concern with designs not having constant-pressure springs because frequent contact with exciter voltage is necessary to keep spring pressure within correct limits. Fortunately, there are now direct drop-in retrofit brushholders available that incorporate insulated handles as well as constant-pressure springs.

Shaft currents can be destructive, so when problems or concerns arise about them, consider adding sensors to detect their presence. If a reliable insulation system has been applied to the proper bearings, and if good shaft grounding is maintained, the probability of damage caused by current flow should be small. But shaft-current measurement may be useful on machines where a concern exists.

Partial discharge

With good sensors and monitoring instrumentation, it is possible to obtain considerable information on machine condition from the PD occurring in the generator. Interpretation of the data's significance is the most difficult aspect of partial-discharge testing. Equipment is available from several suppliers, including most OEMs. Sensors typically are installed on the line buss; installation is relatively simple (Fig 6).

Data analysis. Testing-company approaches to PD data analysis are not standardized. One major PD vendor has relatively simple procedures and instrumentation, and a very large database. This allows a generator owner's engineering personnel to collect and analyze their own data with nominal training.

Other testing vendors prefer to collect the data with their own personnel and instrumentation, and then forward the results to a central engineering group for analysis. Both approaches have given good results in monitoring generator performance.

In several cases, units have been removed from service to investigate high readings, thereby allowing the correction of significant problems before major damage occurred. While some judgment of winding quality is made on absolute readings, all vendors rely heavily on trending of readings over time for a given generator. A winding trending rapidly upward is monitored closely and, depending on readings, may be disassembled for inspection.

While PD monitoring now is common on generators, partial discharge generally is not a major destructive mechanism on mica-based insulation. But PD readings have been found very useful in monitoring stator windings for some critical deterioration mechanisms. Analysis of databases at testing companies with significant amounts of PD data indicate that serious maintenance issues have been found on about 6% of generators.

What can't be monitored—yet

Some deterioration mechanisms not assessed by monitoring equipment are discussed below. Note that these important mechanisms often lead to in-service failures, some catastrophic.

6. Partial-discharge sensor can provide considerable information on generator condition

Stator-bar vibration historically has been a significant root cause of service failure. It tends to cause relatively fast-acting forms of deterioration, with failure occurring within several months to a few years.

Unless bar vibration produces PD or sparking, it won't be identified by any instrumentation available today. The vibration simply will continue—in most cases at an accelerated rate—until the insulation is worn thin and fails, or the vibration results in fractured and failed bar strand copper.

Stator-bar strand-header water leaks. Leaks in the strand-header connection braze are a slow failure mechanism, often taking several years to emerge as problematic. These leaks have resulted in many stator partial and full rewinds—and a few in-service failures. Leaks may be as small as a few ounces of water a week. There is no monitoring device to detect the insulation dampness that occurs from such small leaks, which will continue until an in-service failure, or until it is found by hipot.

Stator-winding connection cracks typically develop over relatively short periods of time—perhaps two or three years of operation, or less. The primary root cause tends to be resonance vibration, which may start immediately after the winding is placed in service if it has not been designed properly and tested.

Or the resonant vibration may develop over a few months or years, as the component's natural resonant frequency decreases into the driving frequency range because of operating temperature and winding wear. Unless vibration detectors are installed in the correct locations, there is no instrumentation which will detect this usually severe deterioration mechanism.

Field coil/turn distortion develops slowly—over many months to several years. There is no way to monitor this condition as it develops. Eventually, deterioration may be detected by developing turn shorts, large increase in required field current, vibration, and/or field ground.

Field-turn cracks generally develop slowly—over a period of from a few to several years. There is no detection until fracture occurs. At this point, current will continue to flow (as in a welding arc). The arc will quickly burn through the insulation and give field-ground indication.

But since industry standards focus on the hazard of a possible second ground, it is unlikely that the generator would be tripped immediately. Thus, arcing and burning of the winding and forgings would continue until vibration levels trip the unit, or components start to fracture, or the machine is removed from service for investigation.

Retaining-ring corrosion and cracking. There is no monitoring of this extremely serious deterioration mechanism, which may occur rapidly. In one recent case, just 18 months after an 18/5 retaining ring had been removed and found satisfactory based on a full NDE (nondestructive examination) series, the ring failed catastrophically. There was no warning of impending danger.

Forging cracks. All forged components in the rotating field are subject to possible cracking. In particular, cracks are being found on the field forging under the retaining-ring shrink fit and the body axial centerline. These cracks seem to identify with designs of specific manufacturers. In general, there is no detection capability for such cracking unless it becomes so large as to affect field vibration.

Concluding remarks

Accurately predicting the timing and scope of maintenance needed on an operating generator is not possible with present state-of-the-art monitoring instrumentation. Even with the best monitoring systems, generators remain with little or no detection capability for several of the more common and serious deterioration failure mechanisms.

The age-old industry practice of five years between inspections certainly is not appropriate for many generators because of their infrequent operation, light duty, age, and relative importance to the system.

However, a 10- or 12-year period between generator inspections seems inappropriate for many machines—such as those (1) in continuous high-duty operation, (2) with known or generic quality issues, or (3) of vital importance to the system. Arbitrary extension of maintenance intervals can result in long, costly, inconvenient, and potentially hazardous forced outages.

Maintenance intervals should reflect all known information on a specific generator, including the following:

- Operating hours.
- Operating duty.
- Importance of the unit to the system.
- Results from previous inspection and maintenance outages.
- Availability of replacement parts.
- Condition assessment based on information gathered by monitoring instrumentation. CCJ

Clyde V Maughan is president of Maughan Generator Consultants, Schenectady, NY. He has 60 years of experience in the design, manufacture, inspection, failure root-cause diagnostics, and repair of generators rated up to 1400 MW from the leading suppliers in the US, Europe, and Japan. Maughan has been in private practice for the last 24 years. He spent the first 36 years of his professional career with General Electric Co.

Get answers to your questions at

www.generatortechnicalforum.org

Virtually all readers of the COMBINED CYCLE Journal are involved in the design, construction, operation, and/or maintenance of facilities to generate electricity. All are keenly aware that the rotating device at the far end of the shaft from the gas or steam turbine is a generator and that it makes what probably is the only product their "manufacturing" plant sells.

Yet generators don't seem to get the respect they deserve on the deck plates or in the corporate offices, at least based on the editors' observations. Programs at the many gas-turbine (GT) users groups serving the industry may have one or two presentations on generators—except for CTOTF-Combustion Turbine Operations Task Force, which allocates half a day—and any follow-on group discussion generally is labored.


Moore

Think for a moment about all the presentations and discussion you have heard on GT inlet filters; how many have you heard on generator air inlet filters? How many generator presentations have you heard users make? One that comes to mind at a recent meeting of F-class owner/operators: A user showed pictures of a generator failure, sprinkled in a few facts, and closed by indicating he wasn't sure of the underlying cause and really wouldn't be comfortable taking any specific questions.

Someone in the audience said a generator at his plant suffered the exact same fate, but he really didn't know much about generators either and had nothing to contribute. There were at least 150 people in the room at the time and no one offered an opinion—that's something rare for a user-group meeting.

But it illustrates the point. The editors attend about 10 GT user-group meetings annually and would be hard-pressed to identify more than about a half-dozen generator experts who have presented at those forums over the last several years. One of those, Bill Moore, PE, of National Electric Coil (NEC), Columbus, Ohio, knows that a presentation here and there does little to help the industry as a whole. Even a meeting focused on generators would have limited value.

So Moore and his colleagues at NEC came up with a better idea, the International Generator Technical Community Inc (www.generatortechnicalforum.org), which the company launched early this year as an independent entity. At its core, IGTC is a robust website with state-of-the-art functionality offering ongoing discussion forums to help solve generator problems in timely fashion. Membership in the group (there's no subscription fee) also allows access to a rapidly expanding technical reference library. Well over 400 members had registered by mid August.

NEC, well respected for its generator field-service and shop-repair capabilities, created IGTC "to pool and disseminate detailed technical information about generators and assist industry professionals leverage opportunities to maintain and improve the reliability of high-voltage machines."

The website presently is organized into 13 discussion groups, each with a moderator having decades of relevant experience in the subject area. Career thumbnails are posted on the website. Moore serves as the so-called forum master, responsible for overall management and for assisting moderators (and assigning new ones) as needed. The current forums and their moderators are:

- Visual inspections, Kim Eiss
- Stator electrical testing, James E Timperley, PE
- Vibration monitoring, Alan Spisak, PE
- Rotor electrical testing, David Albright
- Inner water-cooled stator windings, Clyde V Maughan
- Inner hydrogen-cooled stator windings, James S Edmonds, PE
- Large air-cooled generators, Dr Greg Stone
- Rotor windings, Joseph Romeo
- Rotor mechanical components, Andrew Spisak, PE
- Stator core, clamping systems, and frame, Robert T Ward
- Stator end winding vibration and resonance, Alan Spisak, PE

- Hydrogenerators, Kalman N Lehoczky, PE
- Exciters, Andrew Spisak, PE.

There also is a "Help: How do I. . . .?" button right under the listing of discussion forums to assist members with questions regarding making, editing, and tracking forum posts, etc. Moore handles most of these inquiries himself.

One of the site's most helpful features: Members can identify forums of interest and receive notification by email when something new has been posted in those subject areas. Also, a search function allows members to do key word/phrase searches and to sort the information retreived by date, etc. The information is coded to advise if you had accessed it previously, or if it was posted following your last visit.

Another: You can search the member directory by the user name identified with a particular post to access the person's actual name, title, company, discussion group(s) currently participating in, and any other post he or she has made since joining the group.

The postings on each of the discussion forums are divided into subcategories. For example, the vibration monitoring forum has several posts on rotor blower-blade failures in response to a member question on the root cause of blower-blade failure (a blade broke off at its root six months after a major inspection where all blades passed a penetrant inspection).

Sustainability. A challenge of any web-based enterprise is to maintain member interest. It takes initiative to sign on to the site, which is why email messages on posts in areas of personal interest are so valuable. But Moore and his colleagues take it a step further by having an engaging monthly roundtable for members participate in. Material is archived so you will have access to it if the need arises.

After you register as a member, access the site, click the "forum" button on the horizontal toolbar at the top of the page, then click the link to the roundtable at the top of the following page. The next page has three tabs: "Overview," "Premise," and "Comments." The first discusses the intent of the forum, the second identifies the issue being discussed, and the third presents thoughts already contributed by fellow members.

The first forum, on stator end winding vibration, was conducted in May. The following were among the specific questions members were asked to comment on:

- What are the ideal limits of end winding vibration, and what are the practical limits?
- What size generators should these limits apply to?
- What should be the "exclusion zone" for end winding natural frequencies?
- Are higher harmonic frequencies a concern and to what extent does the global mode shape matter at these frequencies?
- Are fundamental operating frequencies, such as 50 and 60 Hz, a concern with the end winding, or is two times the operating frequency the only concern?

A contributor recognition feature of the forum process is that members are asked to evaluate the commentaries and the person with the highest score wins a prize. Clyde V Maughan of Maughan Generator Consultants, Schenectady, NY, was the top vote-getter in May and was presented with Lands End outerwear.

The MVP (most valuable participant) in the June forum on stator core testing, according to members, was David Bertenshaw of Enelec Ltd. In July, David Tarrant of DTEC was cited for his contributions to the forum on rotor winding integrity using the recurrent surge oscillograph (RSO) method. CCJ

Sponsored Statement

Making waste gas a business opportunity

Background

Gas turbine technology has enabled natural-gas- and fuel-oil-fired combined-cycle plants to achieve efficiencies up to 56-57%. Only in the last 15 years has a different requirement become important to the gas turbine market. A new business area is quickly growing requiring gas turbines to be able to offer good performance also by using low-Btu fuels.

This new requirement is strictly related to the commercial success of IGCC technology, which allows production of electric power from low-quality/low-cost fuels (as refinery residual oils or low rank coals) with an efficiency higher than boiler-based power plants.

Furthermore, gasification technology is coupled to very effective gas cleaning technologies which, in addition to the good performance of the gas turbine concerning the emissions problem, overcomes all the environmental problems related to the combustion of such fuels.

This requirement is also met when dealing with recovery gases from steel-mill processes that also can be burned in a gas turbine instead of a traditional boiler with higher performance and efficiency. All the fuels coming from these processes are mainly constituted by a mixture of carbon monoxide, hydrogen, methane, and nitrogen.

An example of the fuel opportunities mentioned above is given by the experiences in this business area gained by Ansaldo Energia (Table 1). All plants listed are equipped with AE94.2K gas turbines manufactured and directly supplied by Ansaldo Energia.

All the AE94.2K machines are equipped with silo-type combustors and with a proper low-Btu burner to accommodate fuel features and plant requirements. Thus, for each application it has been necessary to introduce some optimization of the burner design.

Table 2 provides an overview of the fuel characteristics in order to highlight the wide range of compositions of these mixtures, depending on the different feedstock to be gasified or the available by-product gas, the chosen gasification technology, and the available added diluents (nitrogen and/or steam).

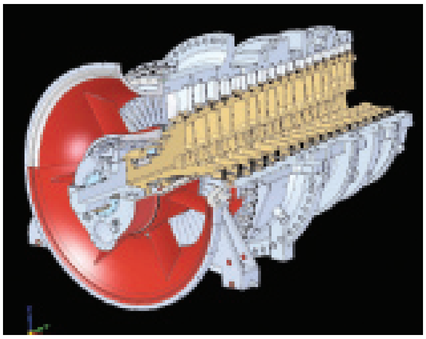


Fig 1: New AE94.2K2 compressor

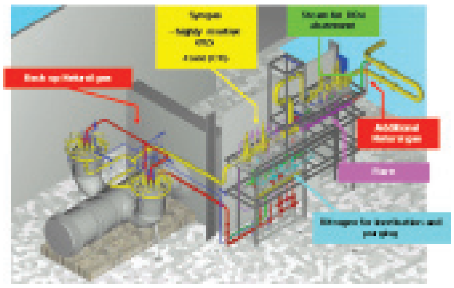


Fig 2: Fuel feed system

Looking at the table, note that the typical low-Btu fuel range is covered by Ansaldo Energia technology. In order to maintain the leadership position in this niche market, a continuous development process has been implemented to allow the existing fleet to burn fuel with a lower heating value (LHV) below 5.0 MJ/kg.

In this fuel range, the standard AE94.2K cannot be profitably employed due to the excessive partialization which would be necessary to operate on compressor inlet guide vanes. To maintain the proven design of the K series, Ansaldo Energia has released the AE94.2K2, featuring reduced air compressor capability. This model accommodates the much more stringent requirements of users of steel-mill by-product fuel.

The new gas turbine features the following:

- New compressor vane-carrier casings with minor changes on compressor vanes.
- Compressor bearing casing changed in the interface towards the compressor vane-carrier casing.
- Rotor unchanged, except for the removal of the first stage, but with the addition of two final stages with the same total length.
- No modification of hot components--that is, the turbine and combustors remain unchanged.
- External casings are unchanged.
- Burners with flow channels for gas of low heating value are designed in relation to Wobbe index and optimized in relation to the fuel used.
- Plant layout and foundations remain unchanged.

Compressor redesign

Depending on the LHV of low-Btu gas, and therefore the fuel flow rate input, a suitable version of the V94.2 can be adopted in order to optimize fuel consumption and energy production.

As mentioned above, the key factor to cover the lower fuel range is compressor redesign to reduce air flow capability. Main changes have been performed to the compressor stages, by removing the first compressor stage and by redesigning the compressor inlet duct to take into account the reduced IGV cross-sectional area.

The compressor inlet duct performance also in the new design condition has been checked by accurate 3D study. In addition to the modification to the compressor first stage, to ensure proper operation in all working conditions, two additional compression stages were also added at the delivery side, in order to restore the previous surge margins.

This simple design concept allowed to limit the number of components involved in the change as much as possible and to use components of proven geometry (the last stages added are identical to the

Table 1: Ansaldo Energia's low-Btu fuel project

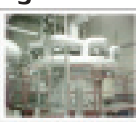
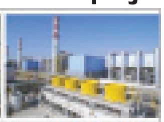
AE94.2K			
Power Plant	ISAB Energy Priolo	Elettra GLT Servola	EniPower Ferrera E.
Net Power (GT/CC)	2x190MW / 518 MW	1x118MW / 170MW	1x 166 MW / 238MW
First Firing (Sec. Fuel/Syngas)	November, 1998 / August, 1999	August, 2000 / November, 2000	March, 2004 / March, 2006
EOH	Unit 1: 90000 / Unit 2: 89000	79000	45000
Fuel Loading	0-100% BL	40-100% BL	0-100% BL
NOx, CO emissions	75/10 ppm	30/10 ppm	25/10 ppm
GT/CC efficiency	34.5/48.5	33/47	36 n.a.

Table 2: Fuel properties

	ISAB Energy (I)	Elettra GLT Servola (I)			EniPower Ferrera E. (I)	
Feedstock	Asphalt	Steel mill process gas			Asphalt	
Gasification	Texaco	-			Shell	
Natural Gas Integration (% thermal input to Gas Turbine)	0%	15-40%			0-20%	
Fuel Gas Temperature	195 °C	260 °C			190 °C	
Fuel Gas Pressure	22 barg	20 barg			22 barg	
H_2/CO ratio	0.85 - 1.01	0.30 - 0.80			0.55 - 0.92	
Fuel Gas Comp. (% vol.)		A	B	C	[illegible]	[illegible]
H_2	31.25	5.00	5.36	1.16	15.71	24.45
CO	29.70	16.21	9.44	17.02	30.48	26.47
H_2O	34.09	5.46	20.05	5.99	46.35	46.70
N_2	0.90	46.36	31.46	49.48	0.41	1.20
CO_2	3.27	13.01	7.40	10.92	1.50	1.57
CH_4	0.10	14.06	26.70	26.80	4.10	0.32
C_2+	0.00	0.00	0.04	0.23	0.70	0.00
LHV [MJ/Nm3]	7.2	8.67	10.11	9.71	7.79	6.21

Table 3: Typical low-Btu

FUEL	A	B
H_2 [% vol.]	4.36	5.6
CO [% vol.]	25.46	22.58
H_2O [% vol.]	4.34	4.3
N_2 [% vol.]	39.76	45.08
CO_2 [% vol.]	28.28	21.05
CH_4 [% vol.]	1.36	2.6
C_2+ [% vol.]	0.74	0.9
H_2/CO [vol]	0.16	0.25
LHV [MJ/kg]	3.62	3.52
Mixed at max load [kg/s]	110	90.6

in the power generation industry

www.ansaldoenergia.com

previous ones). Due to this solution, the external machine layout is unchanged (Fig 1).

Combustion system

The two combustion chambers are arranged vertically on either side of the turbine and connected to lateral flanges on the turbine casing. This design allows concentric gas and air paths form the compressor to the combustion chambers and from the combustion chambers to the turbine, involving relatively low flow velocities and thus minimum pressure drop.

The combustion chamber is provided with a refractory lining. Each combustion chamber has eight separate burners equipped for burning low-Btu fuel as main fuel and natural gas as a backup fuel. The burner design is based on Ansaldo Energia's previous experience on other low-Btu fuel projects (Isab Energy Priolo, Elettra Servola, Enipower), redesigned, and tested in two different test campaigns at Ansaldo Caldaie Combustion Centre and ENEL laboratories in Italy in order to take into account the different boundary conditions which occur for very low-Btu gases.

Table 3 presents several compositions of low-Btu gases as blends of blast furnace gas, coke oven gas, and oxygen. All are suitable for use in the AE94.2K2.

For some blends, natural-gas integration is necessary to reach a suitable LHV. Basically the engine is expected to be ignited and loaded at 40% of base load fueled by natural gas; after the change over to syngas, the engine can run on syngas with the natural-gas integration necessary to get to base load.

The critical point for the burner design process is facing different fuel compositions as the gas turbine is loaded. Therefore a detailed analysis has been performed taking into account the different cases shown in the mentioned table.

This means that for each kind of fuel, optimization of the standard low-Btu burner must be performed, including a numerical analysis (CFD with chemical routines) and a experimental test campaign in order to finalize the proper burner design. As already mentioned, the fuel system for the low-Btu engine has to supply much higher flow rates to the burners than for the standard engine.

The fuel system (Fig 2) consists of large-diameter pipe and control and stop valves, and must include additional mixing in order to get the final blend of recovery gas, natural gas, and, occasionally, steam. The presence of toxic and explosive components demands that the fuel system meet very high safety standards. Thus all flanges and joints between the burners and the connection point to the skids are welded.

According to the gas turbine working conditions, engine loading is performed by using the back-up fuel, mainly for safety reasons. Thus, a procedure for switch over from back-up fuel to the main fuel is accomplished under full automatic control.

The procedure is performed so that before the low-Btu fuel enters the combustor at the change over, its characteristics are monitored and analyzed online. The fuel is flared until the its properties and the design specifications match. Once that happens, the changeover procedure can start.

Finally, a purging procedure before any syngas partial or full-load working condition must be done with nitrogen or steam in order to avoid possible risks of explosion due to the reactivity of the fuel when exposed to mixing with air.

Performance

Table 4 shows the performance that can be expected on V94.2 models when operating on singular fuels, in particular the different types of low-Btu gases.

Conclusions

The growing demand to supply gas turbines with very-low-Btu gases derived from steel-mill processes has driven the introduction of Ansaldo Energia's AE94.2K2, an engine developed for this specific niche market based on the relevant experience achieved on AE94.2 (Table 5). Thus the AE94.2 has proved to be the leading technology for a wide fuel flexibility in power generation.

This model will benefit by all the experience gained in low-Btu fuel market by Ansaldo Energia with the V94.2K. The model was officially released in 2008. Ansaldo Energia is in negotiation with a few customers for a new project relevant to the utilization of different blends of blast furnace gas, coke oven gas, and oxygen.

Ansaldo Thomassen Gulf: A new high-tech repair center in the Middle East

With a major new investment, Ansaldo Energia has significantly increased its service sector dedicated to all customers in the Middle East, one of the fastest developing areas in the world. Through its subsidiary Ansaldo Thomassen Gulf, Ansaldo Energia has built a futuristic new operations facility which was officially opened at the end of April 2010. The inauguration ceremony was organized with the backing of sheik Hamad bin Zayed Al Nayan. Guests included Ansaldo Energia CEO Giuseppe Zampini, Ansaldo Thomassen Gulf CEO Fausto Nepote, ZonesCorp CEO Mohammed Hassan Al Qamzi, and Paolo Dionisi, the Italian ambassador to the Arab Emirates.

The new facility, which has 3,200 sq m of workshop floor and 880 sq m of offices, will play a fundamental role in satisfying the needs of the local market in terms of quality and time.

Ansaldo Thomassen Gulf draws on the latest technology and the best human resources to provide an international centre of excellence in gas turbine repair and maintenance, while eliminating high costs of international transport for its customers. This represents a decisive step towards Ansaldo Thomassen Gulf's goal of becoming a point of reference in the service and repair market for all technologies of turbine, offering an innovative service for the first time in this area, with a structure that is rapid, professional, highly efficient, and easily accessible.

fuel composition

	C	D	E	F
	9.94	9.77	3.13	6.93
	35.29	22.65	31.22	21.11
	4.39	4.23	4.32	4.33
	34.86	43.53	39.73	39.9
	15.62	21.26	20.53	19.63
	3.02	3.6	1.59	4.84
	0.9	0.95	0.85	1.07
	0.30	0.17	0.1	0.47
	4.97	3.64	3.65	4.49
	66.54	60.3	64	86

Table 4: AE94.2 family performance

Model		AE94.2	AE94.2K	AE94.2K2
Fuel		Natural Gas	Syngas Medium LHV	Syngas Low LHV
GT Power Output	[MW]	166	170	170
Grid frequency	[Hz]	50	50	50
Compressor ratio	-	11.4	12	10.7
Exhaust mass flow	[kg/s]	531	540	511
Exhaust temperature	[°C]	544	545	559
GT efficiency	[%]	34.5	36	36
Fuel LHV	[MJ/kg]	50	9	3.6

Table 5: AE94.2 family features

Engine Model	AE94.2	AE94.2K	AE94.2K2
LHV	35 ÷ 50 MJ/ kg	7 ÷ 35 MJ/ kg	3.5 ÷ 7 MJ/ kg
Compressor	Standard	K model	K2 model
Combustor	Standard	Standard	Standard
Burner	Standard	K model	K model, enhanced
Turbine	Standard	Standard	Standard
Fuel System	Standard	K model	K model, enhanced
Control System	Standard	K model	K model, enhanced
Lay out	Standard	Standard	Standard

Class *of* 2009/2010

OSU Energy Center

Corvallis, Ore

Oregon State University

A great leap forward

With apologies to George Bernard Shaw, consider that combined-heat-and-power plants (CHP) and utility-class combined cycles are two types of gas-turbine-based generating facilties separated by a common technology. Both require the same level of engineering expertise to design and build, but cycle complexity and size differ markedly because of specific needs and operational goals.

Funding assured, permits in hand, and major equipment on order—that is, gas turbines (GTs), heat-recovery steam generators (HRSGs), and steam turbine (ST)—an experienced EPC contractor probably can have a garden-variety 500+-MW 2 × 1 F-class combined cycle in service within two years.

CHP plants rated less than 10 MW, which can have a long gestation period before a "go" decision is made, easily can take three years or more to design and build. This may sound difficult to believe if you're a big-plant person, but "small ball" is a different game entirely.

Meeting the commercial operating date is critical when building large generating facilities. There are revenue targets to hit and unemployment lines for those who don't achieve the goals prescribed. Fine-tuning of design to meet dispatch requirements that might change during the project generally can wait until an outage.

Major institutions, by contrast, replace their energy centers every half century—give or take a decade. For them, major goals are high reliability, low life-cycle cost, top efficiency, infrastructure that blends with campus surroundings, accommodating expected growth in student population and research projects, etc.

Design/construction reviews are seemingly endless and involve disparate groups, some with virtually no powerplant experience. If the schedule slips to achieve a consensus among the groups, then that generally is acceptable. Experience in designing and building Oregon State University's new CHP facility in Corvallis is a case in point.

Larrie Easterly

1. OSU Energy Center looks more like a research lab than a powerplant. Standing just outside the building it's difficult to believe there are three boilers, one gas turbine, and one steam turbine inside

A proud institution

Accepting that pride, image, and academic achievement are as important to a univeristy as profit is to a merchant power producer, makes it easy to understand the decisions made during design of the OSU Energy Center. Oregon State's website attests to its proud heritage.

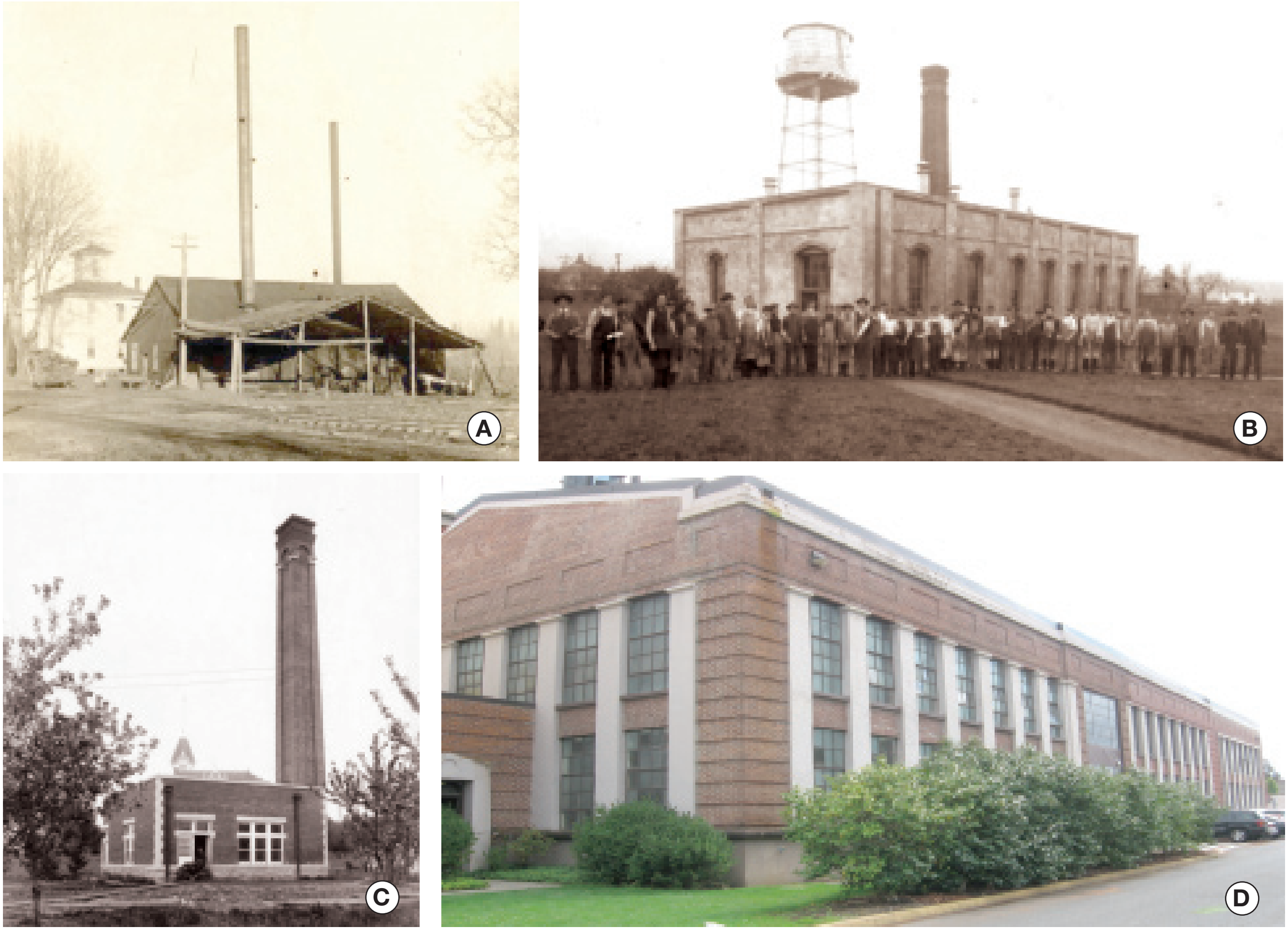
Founded in 1868, it is Oregon's *Land Grant* university and only one of two institutions in the US to have *Sea Grant, Space Grant,* and *Sun Grant* designations (Sidebar 1). It is the state's largest public research university and had a record $252 million in research funding in 2008-2009, some of that associated with the development of biofuels.

"Can-do" thinking and action places OSU fourth among universities nationwide in the use of renewable energy, first in the Pac-10 Conference. To illustrate just how far Oregon State will go to reduce its carbon footprint and embrace renewables, consider that 22 exercise machines at the campus recreation center are connected to the grid.

OSU touts its energy center as an example of a multi-purpose/multi-benefit facility which can serve as a model for others (Fig 1). The new central plant was long overdue. The steam plant that had served the campus until the 2009/2010 heating season was built in 1923 and expanded in 1948. Only three of the five remaining boilers still worked when it was decommissioned in June 2010. The equipment simply was worn out. That was the fourth central plant to serve the campus (Fig 2).

Easterly

Larrie Easterly, the university's engineering manager and project manager for the OSU Energy Center, told the editors there



2. Through the years five central plants have served OSU. The first four only provided steam to the campus distribution network. The original heating plant, which began operating around 1880, was wood-fired (A); a modern oil-fired was added in the early 1900s (B). Next, the first plant was replaced with the oil-fueled facility in photo C. The heating plant built in 1923 was expanded in 1948 (D) and served until June 2010

really was no alternative to a new central plant. The existing facility was challenged by mechanical problems, and were a boiler fail during the heating season there would be insufficient steam to meet demand. Even with all operable boilers firing, if the air temperature dropped below 27F there was not enough steam to heat the entire campus.

In addition, a seismic analysis of the building shell early in the new

1. What the terms mean

Land Grant universities were established by the Morril Act of 1862, which was signed into law by President Abraham Lincoln. Their mission is to serve the educational needs of "the people" and contribute to their economic and social well-being.

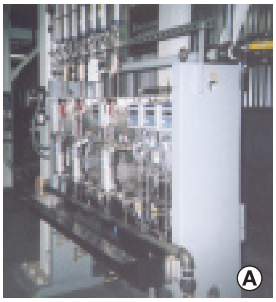
Sea Grant supports an integrated program of research, education, and public outreach to help people understand, responsibly use, and conserve ocean and costal resources. Programs are organized under the National Oceanic and Atmospheric Administration in collaboration with major universities and in partnership with hundreds of public and private marine enterprises.

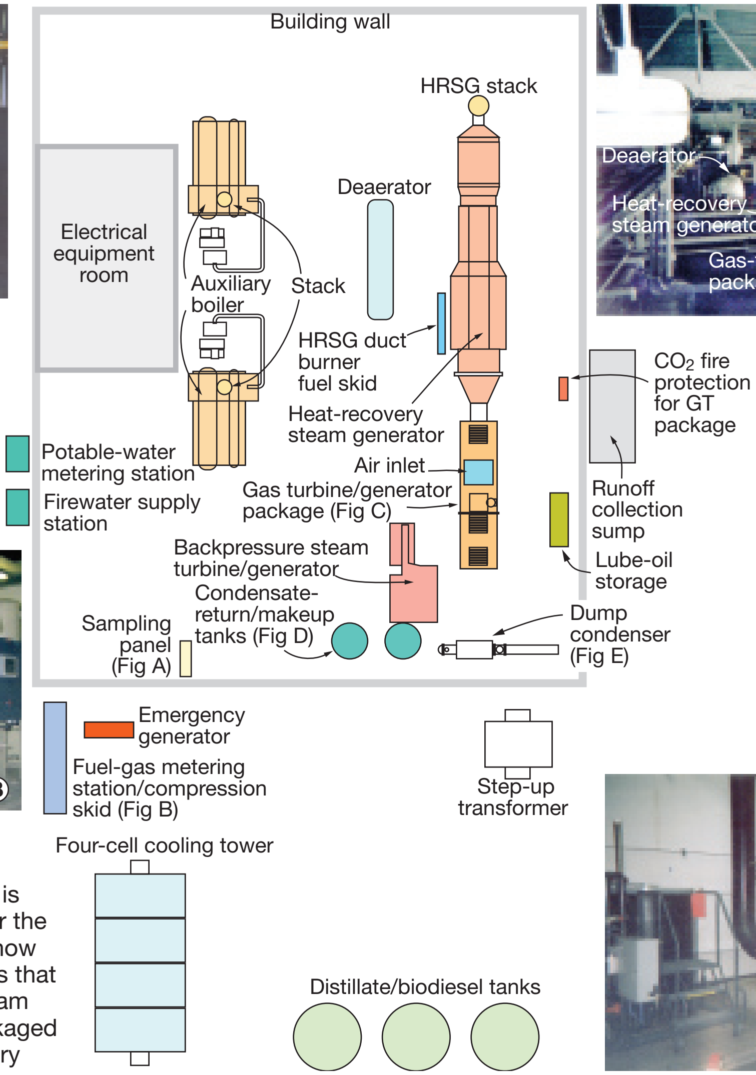
Space Grant program was established by NASA as a network of colleges and universities, space-related industry, government, and others to promote space science and engineering.

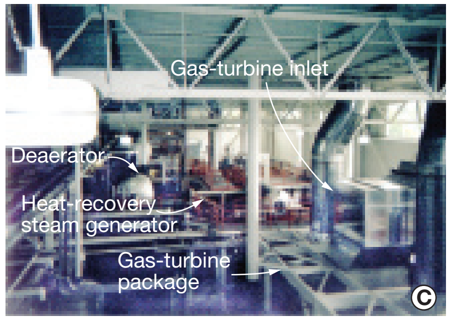
Sun Grant initiative is a network of Land Grant universities and federally funded laboratories working together to establish a bio-based economy.

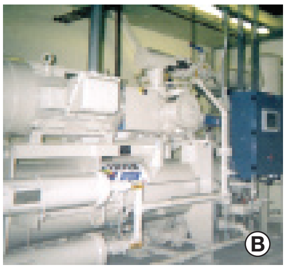
2. By the numbers

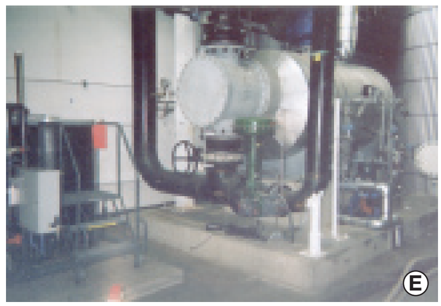
2................miles of steam tunnels
6.3.............megawatts of generating capability
9................miles of steam pipe
98..............buildings connected to the steam system
570............campus area in acres
1889..........year oldest campus building (Benton Hall) was built
4100..........teaching and research faculty in 2010
6500..........teaching and research faculty expected in 2025
22,000.......student population in 2010
23,000.......square feet of floor space in the OSU Energy Center
35,000.......student population expected in 2025
224,500.....theoretical peak demand in lb/hr of steam
250,000.....steam production capability in lb/hr
7.6 million .area of academic, research, and support spaces in square feet











3. Principal equipment is identified in floor plan for the energy center, photos show some of the components that support the gas and steam turbine/generators, packaged boilers, and heat-recovery steam generator: sampling panel (A), gas compression and cleanup skid (B), condensate return/makeup tanks (D), and dump condenser (E). Photo C is a view from the upper balcony

millennium revealed that a $7-million investment would be required to bring the plant into compliance with modern safety standards.

One of Easterly's first assignments when the experienced engineer joined the university's Facility Services group headed byVincent Martorello in 2003: Study the cost and benefits of upgrading the existing plant structure and refitting it with new boilers, then compare those results to the cost and benefits of a new plant. Easterly also was asked to identify the best campus location for the new facility in case that was the option selected.

At about the same time, OSU was experiencing reliability issues with its electric supply and distribution system. So the idea of installing a CHP plant was suggested with the added benefit of producing about half the electricity required by the campus and reducing the university's annual electric bill by about $1.5 million. At least one consultant said the cost of a cogeneration plant would be only about $5 million more than a basic steam plant. Yet another advantage of CHP was a reduction in Oregon State's carbon footprint.

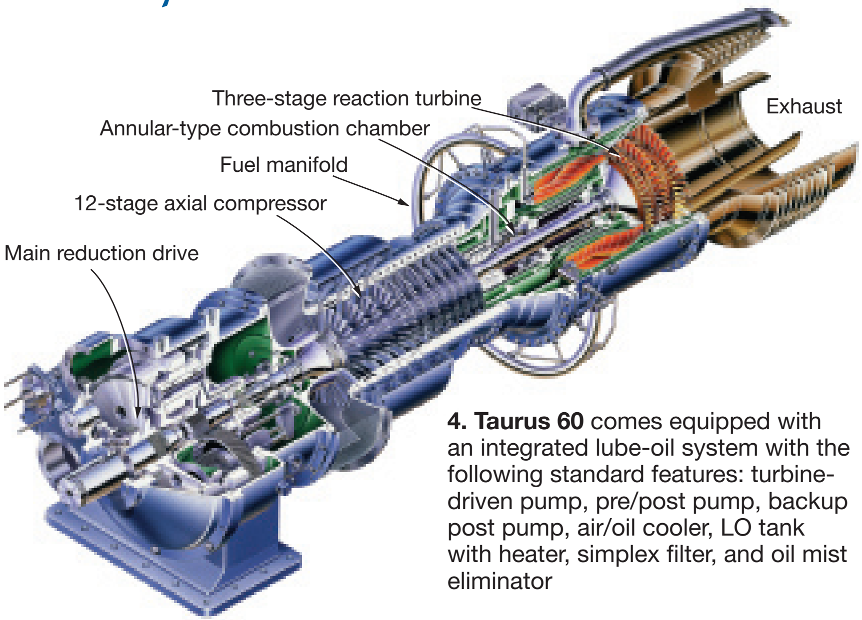
Easterly told the editors that the benefits of CHP were compelling and the university set about lining up the funds a feasibility study estimated would be required to install a new powerplant on the west side of the campus. Note that decommissioning of the existing powerplant at the campus center would open up valuable real estate for learning facilities.

Arranging for funding and gaining required approval by the state legislature took more than three years. In sum, $49 million was required to complete the project. Financing was complex and not all funds were available at the start of construction. Specifically, tax credits and grants were received after project completion.

Funding came from OSU Facility Services reserves, state bonds, grants from The Climate Trust and Energy Trust of Oregon, and a tax credit from the Oregon DOE. State bonds will be paid back from the cost saving provided by the CHP facility over a conventional steam plant.

The Climate Trust grant acknowledged CO_2 offsets of 46,726 tonnes/yr; the Energy Trust of Oregon specified a heat rate to beat of 5540 Btu/kWh (fuel chargeable to power) and the plant achieved 4491; the Oregon DOE tax credit was contingent on installation of the backpressure steam turbine/generator.

The Portland office of Jacobs Engineering Group Inc was hired as the university's prime architect/engineer—in effect, the owner's engineer. It determined the optimal size and design of the facility, evaluated the use of two gas turbines versus one,



4. Taurus 60 comes equipped with an integrated lube-oil system with the following standard features: turbine-driven pump, pre/post pump, backup post pump, air/oil cooler, LO tank with heater, simplex filter, and oil mist eliminator

and did as-built drawings, pre-purchase specs, bid packages, testing of components it designed (grid synchronization, for example), etc.

Portland-based Andersen Construction Co was selected as the construction manager and general contractor. It sent out bid packages and purchased equipment. Another Portland company, Heery International Inc, was the commissioning agent and witnessed all testing and verified work was done correctly.

Platinum LEED. Easterly said the energy center was designed to the highest LEED (Leadership in Energy and Environmental Design) standards and is Oregon State's first platinum project. Green features include rainwater "harvesting" for boiler makeup, use of heat recovered from condensate to make hot water for domestic use and space heating, passive (natural) ventilation, natural lighting, use of low-VOC and recycled materials to the extent possible, and radiant heating for occupied spaces.

Additionally, building electrical efficiency is 52% better than that required by the Oregon Building Code. Part of this is attributed to the use of variable-frequency drives on all driven equipment rated more than 100 hp; 440 V is standard for these machines. Water consumption is minimized by capturing rainwater and designing plant systems to minimize losses. Electric transmission losses are reduced by onsite power production.

The plant

Were you to stand on the upper balcony of the OSU Energy Center and look down, the equipment identified in Fig 3 is in view. The plant generates a nominal 6.5 MW on the "ideal" winter day and can provide up to 250,000 lb/hr of 60-psig saturated steam to the campus network, about 10% more than the theoretical thermal peak demand at this time (Sidebar 2).

The cogeneration process begins with the nominal 5.5-MW Taurus 60 GT from San Diego-based Solar Turbines Inc (Fig 4, Sidebar 3). The unit's dry low emissions combustion system, trademarked SoLoNO$_x$, restricts NO$_x$ discharges to 15 ppm on natural gas, 65 ppm on liquid fuel. CO controls are not required by the state, although site emissions are restricted to 99 tons/yr. Annual NO$_x$ emissions from the plant may not exceed 74 tons/yr. PM10 cannot exceed 14 tons/yr, VOCs 39.

Primary fuel is natural gas, which is supplied at about 100 psig and boosted to the GT requirement of 325 psig with a prepackaged compression system equipped to remove both entrained liquids and particulates. Distillate oil is the backup fuel; plant is permitted to operate up to 30 days continously on oil. Three

3. Principal equipment

Heat-recovery steam generator, 1 .... Rentech Boiler Systems Inc
Generates 25,000 lb/hr of 200-psig steam without supplementary firing; with duct burners in service, unit can produce more than 80,000 lb/hr

HRSG supplementary firing system, 1 .... R&V Engineering bv
Two burner system is capable of operating on distillate oil, biodiesel, natural gas, and methane. Final heat trap (after the economizer) is a condensate heater designed to Section 8 of the ASME Code and equipped with ASTM 2205 stainless steel tubes

Packaged boilers, 2 .... English Boiler & Tube Inc
Each produces up to 85,000 lb/hr of 200-psig saturated steam on oil as well as gas

Combustion systems for packaged boilers, 2 .... Coen Company Inc
Each Delta NO$_x$ type capable of firing both distillate oil, natural gas, biodiesel, and methane; turndown is 40:1

Gas turbine/generator, 1 .... Solar Turbines Inc
5.5-MW Taurus 60 single-shaft engine equipped with company's dry, low-emissions (SoLoNOx) combustion system. Twelve-stage axial compressor has a 12.2:1 pressure ratio; turbine is reaction type, three stages. Wye-connected generator is a synchronous machine with a brushless exciter. Unit is capable of operating on distillate oil, biodiesel, natural gas, and methane. Space is provided in the inlet duct for chiller coils should they be required in the future

Gas compression/conditioning skid, 1 .... Vilter Manufacturing LLC

Steam turbine/generator, 1 .... Elliott Co
1-MW, two-stage backpressure turbine with Kato Engineering Inc generator operates on 200-psig saturated steam and discharges 60-psig steam to the campus thermal network

Dump condenser, 1 .... Ambassador Heat Transfer
Handles up to 27,000 lb/hr

Cooling tower, 1 .... Baltimore Air Coil Co
Four cells, mechanical-draft type, makeup source is city water

Plant automation system .... Emerson Process Management
DeltaV type

Programmable controllers......................... Allen-Bradley/Rockwell Automation

Steam/condensate piping (direct buried)............ Rovanco Piping Systems Inc

30,000-gal vertical liquid-fuel tanks are located just outside the building proper.

In addition, the GT and the HRSG are designed to burn methane and liquid biofuels in support of university research. Depending on the level of biofuel production, one of the distillate tanks may be used for its storage.

The HRSG, designed and built by Abilene-based Rentech Boiler Systems, is very similar to a packaged boiler (Fig 5). Unit is designed to produce 25,000 lb/hr of 200-psig saturated steam without supplementary firing when the GT is at maximum output. This allows the boiler to comfortably meet the campus summer thermal demand of about 15,000 lb/hr.

To match the thermal requirement, operators can send excess steam to the dump condenser. If the dump condenser is used, heat is rejected in the four-cell cooling tower alongside the building. When the dump condenser is not in service, only one cell of the tower is needed to accommodate all of the plant's other heat-rejection needs.

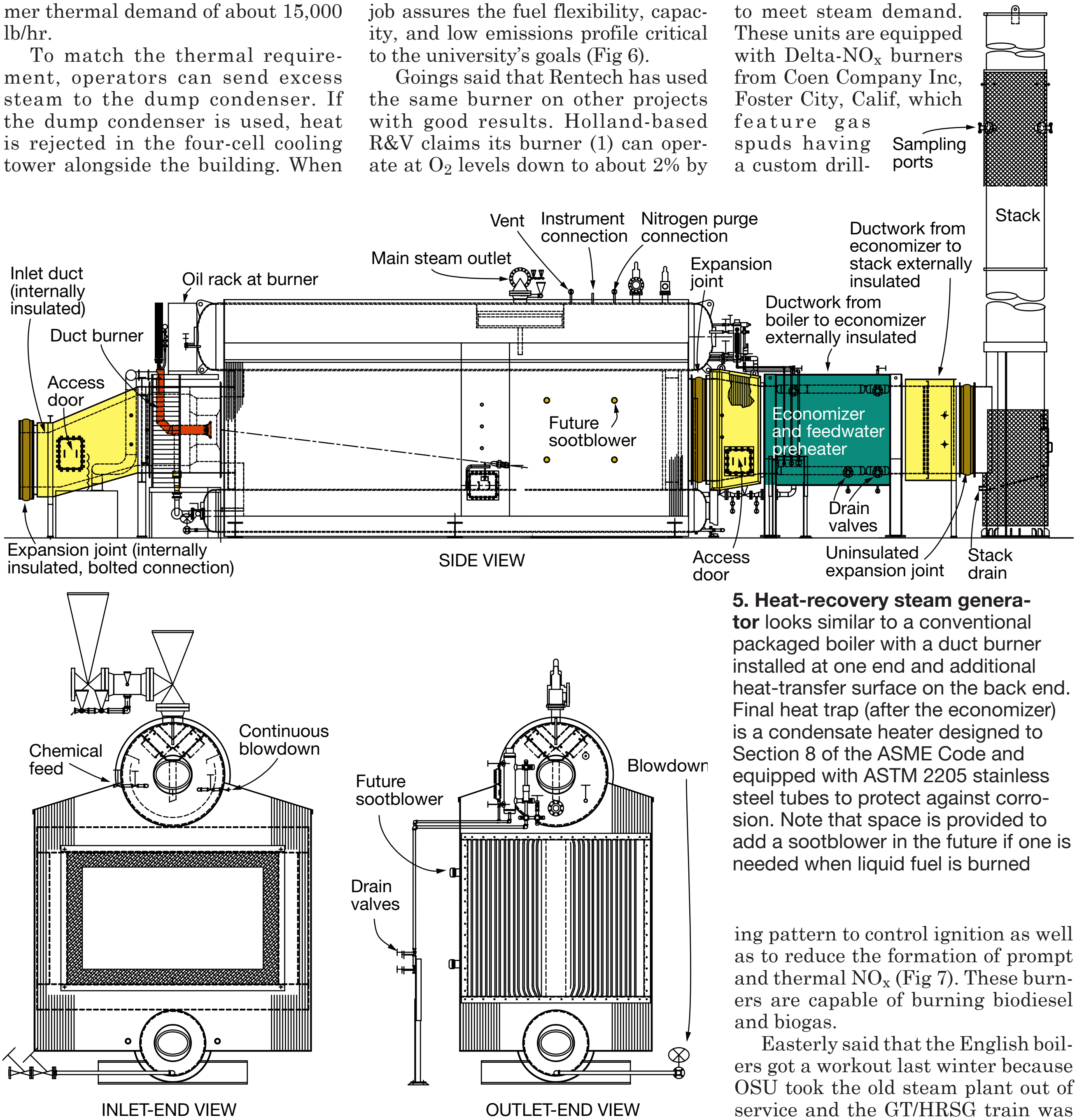
If the university expands as projected, unfired steam production might not be sufficient to meet summertime needs. Options to make up the shortfall include turning on the duct burner or adding a chilled-water coil in the front end of the GT to boost its output and, therefore, exhaust-gas flow. The turbine's inlet air system was designed to accommodate a coil if a chiller becomes economically viable.

Rentech's project manager for OSU, Cory Goings, told the editors that the R&V Engineering bv supplementary firing system selected for the job assures the fuel flexibility, capacity, and low emissions profile critical to the university's goals (Fig 6).

Goings said that Rentech has used the same burner on other projects with good results. Holland-based R&V claims its burner (1) can operate at O_2 levels down to about 2% by volume (dry) without significantly increasing CO emissions and (2) that the supplementary firing system can achieve turndowns of up to 5:1 on liquid fuels.

The combustion system relies on a low-pressure air system (plan view in Fig 6) to atomize liquid fuels and provide flame stability virtually irrespective of GT exhaust gas conditions—such as velocity, pressure drop, temperature, etc. When firing at maximum output and with the GT at full load, the HRSG can produce up to 80,000 lb/hr.

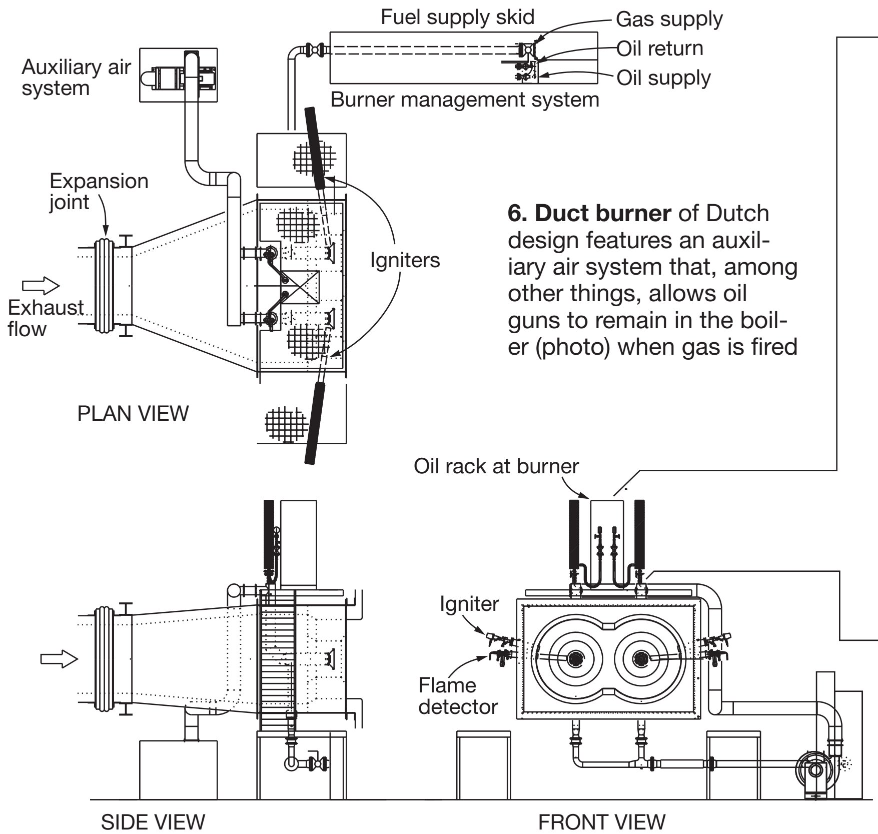
Packaged boilers. Two 85,000-lb/hr gas/oil-fired packaged boilers from Richmond-based English Boiler & Tube Inc are used as necessary to meet steam demand. These units are equipped with Delta-NO_x burners from Coen Company Inc, Foster City, Calif, which feature gas spuds having a custom drill-

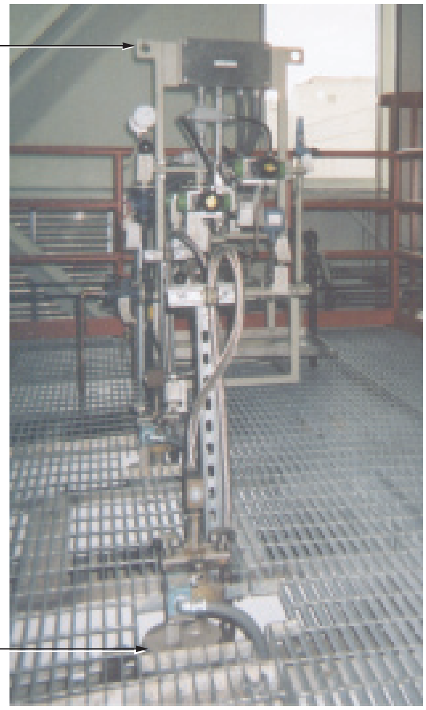


5. Heat-recovery steam generator looks similar to a conventional packaged boiler with a duct burner installed at one end and additional heat-transfer surface on the back end. Final heat trap (after the economizer) is a condensate heater designed to Section 8 of the ASME Code and equipped with ASTM 2205 stainless steel tubes to protect against corrosion. Note that space is provided to add a sootblower in the future if one is needed when liquid fuel is burned

ing pattern to control ignition as well as to reduce the formation of prompt and thermal NO_x (Fig 7). These burners are capable of burning biodiesel and biogas.

Easterly said that the English boilers got a workout last winter because OSU took the old steam plant out of service and the GT/HRSG train was





6. Duct burner of Dutch design features an auxiliary air system that, among other things, allows oil guns to remain in the boiler (photo) when gas is fired

not ready to operate. The two packaged units carried the university through the unseasonably cold (10F) weather while operating at up to 85% of their full-load rating, thereby proving the plant's optimal design.

Boilers in the old plant were maintained on standby last spring and were required only when electrical work dictated that the OSU Energy Center be taken out of service. That experience, Easterly added, was enough to convince any skeptic that the time was right for retiring boilers installed in the 1950s and 1960s.

Steamer. The 1-MW, two-stage backpressure steam turbine from Elliott Co, Jeannette, Pa, acts as a reducing valve, ingesting 200-psig steam from a header common to all three boilers and discharging at 60-psig to the campus thermal network. A standard reducing valve accomplishes same when the ST is out of service.

Easterly said there was significant discussion at the design stage regarding both steam pressure and the size of the steamer. One of the design challenges, he continued, was to find the "sweet spot" in terms of pressure to minimize use of the dump condenser. Pressures as high as 600 psig were considered to increase ST output, but going that route would have meant larger towers, a larger dump condenser, etc, and was not cost effective for a campus the size of OSU's and the historically mild Oregon climate.

The university and its design team worked closely with the Oregon DOE regarding the ST rating and its impact on plant performance to assure that the energy center met the latest state standards while providing an optimum return on the investment and assuring the project would qualify for an Oregon DOE tax credit.

Another contractor, JH Kelly, Longview, Wash, assisted with the setting of large equipment and was responsible for procurement and installation of auxiliaries—including pumps, tanks, pressure vessels, water softeners, and piping for major systems (Sidebar 4).

7. Combustion system and controls for the packaged boilers are designed to produce a minimum amount of NO_x when burning either gas or liquid fuel

4. Key participants

Design team

Jacobs Engineering Group Inc..... Prime architect/engineer
Oh planning+design.................. Building architect
WHPacific .... Civil work and landscaping
Interface Engineering .... Building mechanical and electrical
Green Building Services Inc...... LEED certification

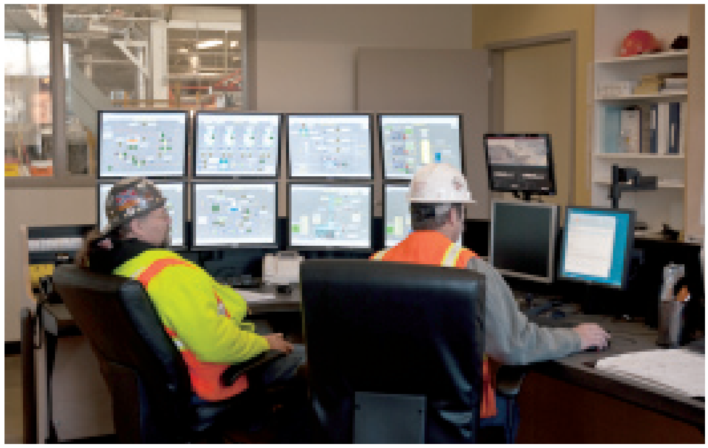
Contractors

Andersen Construction Co .... Construction manager/general contractor
JH Kelley LLC .... Mechanical
Christenson Electric Inc .... Electrical
CH2M Hill............................... Controls integration

Commissioning

Heery International Inc .... Building commissioning
LotusWorks .... Training

8. Preinsulated steam pipe connects the cogeneration plant to the existing steam network five blocks away



9. Oregon State's operations team vaulted into the modern world when the new energy center was installed. Plant personnel traversed a half century of controls technology development in one step

Kelly engineers used the latest modeling techniques to avoid field problems (and costly changes that can result) and to expedite pre-fabrication.

Thermal network. Location of the OSU Energy Center on the campus fringe required installation of 2600 ft of 24-in.-diam steam piping and 6-in.-diam condensate return line to connect the building into the existing grid. In addition, some of the piping in the existing campus steam tunnel was upgraded to assure long life and to reduce thermal losses. Note that air conditioning generally is not required in this part of Oregon so a chilled-water circuit is not installed.

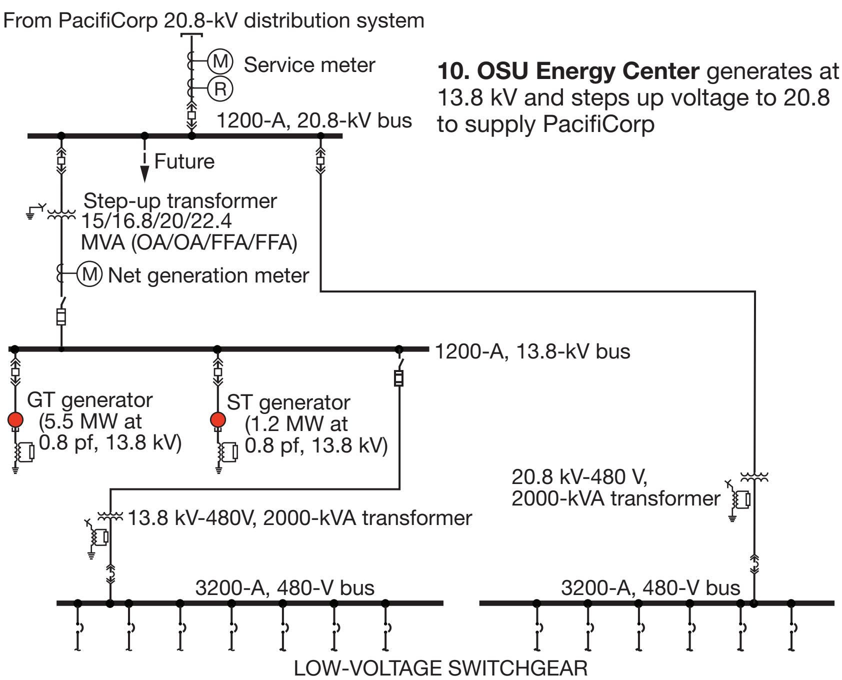
The steam and condensate lines from the plant to the tunnel run about five blocks and are of the direct-buried preinsulated type—that is, the mild steel steam pipe is insulated with mineral wool and an air gap separates that insulation from an outer steel conduit with a 20-mil fusion-bonded epoxy coating (Fig 8). Sacrificial-anode bags prevent corrosion; their condition is monitored and bags are replaced as necessary.

The campus pipe tunnel is concrete and walkable. Spur pipes deliver steam to individual buildings. The older structures have steam radiators, the later ones hot-water converters. Steam consumption currently is monitored for buildings that use the most thermal energy—such as dining halls and athletic facilities—but the monitoring program is being expanded.

Heating of offices in the energy center is accomplished by an in-floor radiant circuit. Heat is extracted from condensate returns by a plate-and-frame heat exchanger installed for this purpose. Note that condensate returns to a small new building near the old plant to take advantage of existing infrastructure. Condensate is pumped from there to the energy center.

Plant operating staff is headed by Plant Manager Steve McKinney. There are six operators with Les Walton in the lead (Fig 9). Most of the maintenance is handled by the operations team. When more help is needed, other members of Martorello's Facilities Services get a call.

OSU Energy Center operates in parallel with the grid and can run in the island mode. The power generated typically is used on campus and only a small amount is exported on summer evenings when campus demand is light; PacifiCorp supplies power when the energy center can't



10. OSU Energy Center generates at 13.8 kV and steps up voltage to 20.8 to supply PacifiCorp meet demand internally. Fig 10 illustrates how the campus distribution system works and how the cogeneration plant interfaces with the utility.

Lessons learned

Easterly's closing remarks focused on lessons learned. Here are some of his thoughts:

- **University management and staff.** Keep staff involved to maintain schedule and control. Examples include reviewing drawings, providing site observation reports during construction, and participating in factory acceptance tests.

  It's important to recognize early that someone on staff must have experience running a cogeneration plant. Work with the HR department to evaluate current staff capabilities, assess the personnel needs of the new facility, and determine who fits (and where) and who doesn't.

  Hire new people as needed, find positions for those who can't make the transition, and begin a rigorous training program for the new operations team. Data point: OSU spent more than $250,000 on training, not including staff time. Easterly believes you can never provide too much training for the O&M staff.
- **Design and engineering.** Easterly does not embrace lump-sump contracts. His experience suggests time and materials contracts with not-to-exceed dollar amounts per phase. Another suggestion: Budget frequent trips to the offices of the architect/engineer to follow project progress up close. Make sure requested design changes are made.

  Think through cost-saving ideas carefully, he warns. If you don't, they may come back to haunt you. Other lessons: warranties start at substantial completion not start-up; prevent confusion by specifying noun names for equipment tagging.
- **Construction.** During the contractor selection process, select someone with a mechanical background as project manager, someone with an electrical background in power station work as MEP superintendent, and someone who loves the details as superintendent.

  Give the contractor direct access to the design team and have the contractor lead the 30-day reliability run. Also, assign the contractor responsibility for equipment purchases. CCJ

Class *of* 2009/2010

Stony Brook Energy Center

Ludlow, Mass

Massachusetts Municipal Wholesale Electric Co

Assets well cared for get better with age

1. Stony Brook Energy Center has a 3 × 1 combined cycle (stacks in the foreground) and two peakers. All gas turbines are 1980-vintage GE 7E

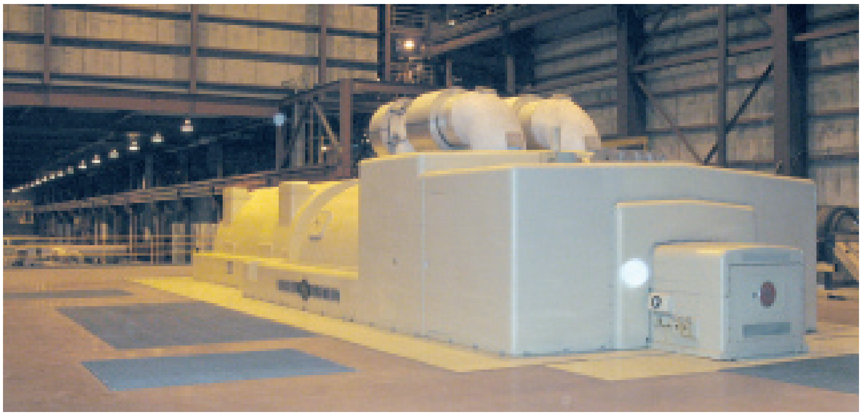
Stony Brook Energy Center is not your typical gas-turbine-powered generating station (Fig 1). Most of the nation's combined cycles were built during and after the bubble of the late 1990s/early 2000s basically by setting equipment on a slab of concrete in a vacant field and wrapping the package with architectural siding. Nothing special.

Massachusetts Municipal Wholesale Electric Co's (MMWEC, pronounced "em wek") Stony Brook, which began commercial operation nearly 30 years ago, was built by Bechtel Power Corp and General Electric Co at a time when designers and owners thought GT-powered generating facilities should be engineered conservatively and look like traditional powerplants (Sidebar 1). Standing on the plant's spacious steam-turbine deck, for example, you get the feeling that an entire F-class 2 × 1 combined cycle might be shoehorned into an equivalent amount of space today (Fig 2).

The quiet 350-acre site in Ludlow, Mass, is home to many species of wildlife and while accessible, can be challenging to find. It is not readily visible from town roads—at least when there are leaves on the trees—and many locals don't know the plant exists.

1. Who is MMWEC?

The Massachusetts Municipal Wholesale Electric Co is a not-for-profit public corporation and political subdivision of the Commonwealth of Massachusetts. It was created in 1976 through an Act of the Massachusetts General Court as a Joint Action Agency. MMWEC provides a broad range of power supply, financial, risk management, and other services to improve the competitiveness of the state's municipal utilities. Using its statutory tax-exempt financing authority, MMWEC has issued more than $4.4 billion in bonds to finance and refinance its 720-MW ownership in five New England powerplants—including Stony Brook.



2. Nominal 100-MW steam turbine guards one end of the building and looks down on the gas-turbine "alley"

The grounds themselves draw you back to a time before the plant was built, when this "reservation" was federal property and home to perhaps the largest nuclear weapons storage facility on the East Coast. Three widely separated concentric fences, one electrified with voltage in the Cold War days, wrapped the site and allowed intimidating patrols by guard dogs, vehicles, and armed personnel.

3. Gas turbines as they look leaning over the turbine-deck rail. The heat-recovery steam generator serving the first GT in the picture is to the right

The physical security, although no longer intact, surely would have made the guards in *Stalag 17* or *The Great Escape* envious. The sections of fence that remain, the empty munitions bunkers (some now storerooms), and the abandoned pillboxes contribute to the plant's "charm." There probably is no other powerplant site like this in the nation—perhaps the world.

Winkler

Corbiere

Background

Plant Manager Karl Winkler has been at the plant since it was built, as have some others. Winkler met the editors at the gate and ushered them into his office for a backgrounder before the requisite tour. Operations Supervisor Glenn Corbiere joined the discussion. First item on the agenda was a review of the physical assets. Stony Brook consists of a 354-MW Intermediate Unit and a 172-MW Peaking Unit, Winkler said (Fig 3).

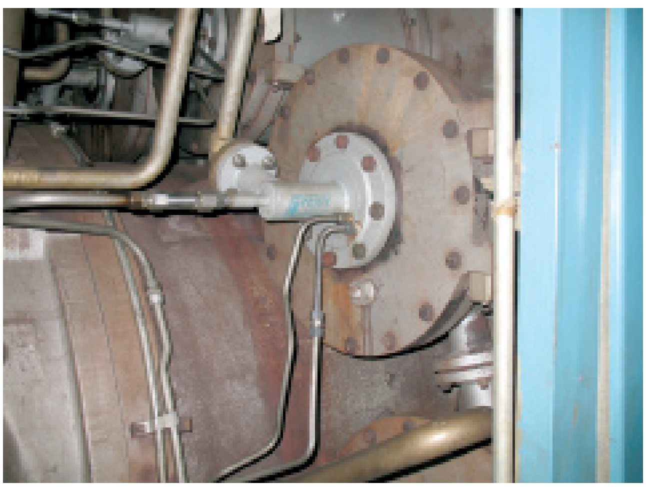
The former is a 3 × 1 combined cycle, which was powered by three distillate-only Frame 7Es when commissioned in 1981. It is owned by MMWEC (90.75%), Green Mountain Power Corp (8.8%), and the Vermont Village of Lyndonville (0.44%). As a Joint Action Agency for Massachusetts municipal utilities, MMWEC sells the output from its share of the Intermediate Unit to 24 municipals. The peaking unit, owned entirely by MMWEC, consisted of two distillate-only simple-cycle 7Es when it was completed in 1982, and still does (Fig 4). Participants in this asset include 22 Massachusetts municipal utilities.

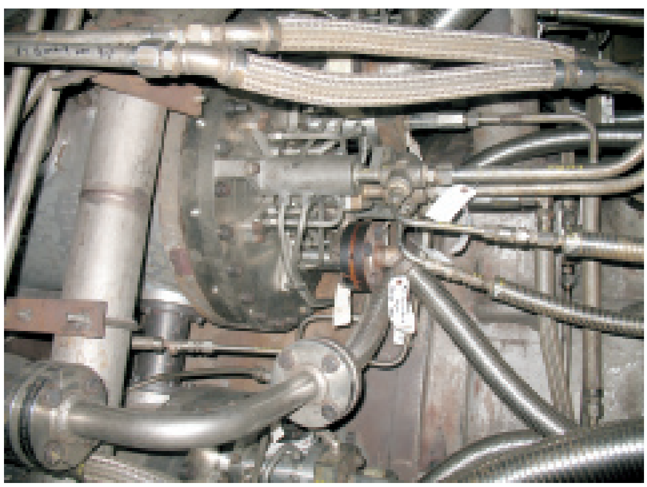
GTs were designed for liquid fuel because no gas was available at the site when the plant was built. Diffusion burners were installed on the combined-cycle GTs with steam injection for NO_x control; permit limit was 75 ppm at COD. Diffusion burners with water injection for NO_x control were specified for the peakers because there was no steam available for them. Corbiere mentioned that he prefers steam over water for NO_x control because the former is conducive to gentle combustion and offers a better heat rate.

All engines came equipped with the Speedtronic™ Mark II control system and its associated Integrated Temperature System. ITS provided exhaust-temperature averaging and other functions, and controlled water and steam injection. One GT serving the Intermediate Plant and one of the peakers have black-start capability. All generators are hydrogen-cooled.

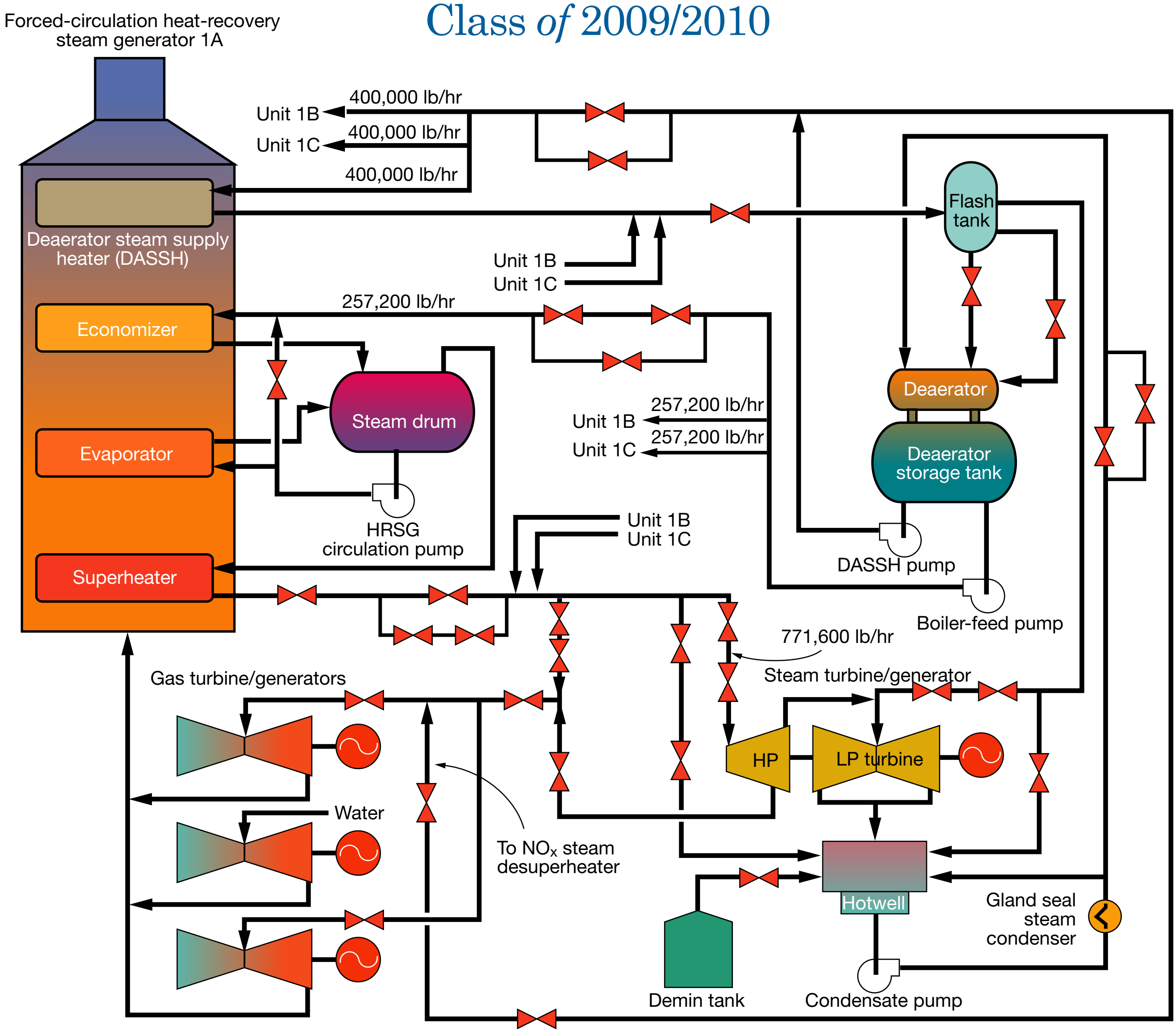
Natural gas. A limited supply of low-pressure natural gas became available to the plant in 1983 and MMWEC converted the three combined cycle GTs (known as 1A, 1B, and 1C) to dual fuel. Booster compressors were added at the same time. The peakers remained oil-only. A new gas line for the Intermediate Unit was commissioned in September 2002.

An air permit change in 1995 reduced the 75-ppm NO_x cap to 42 ppm on gas, 65 ppm on oil. Aware of the impending permit change a year earlier, MMWEC conducted a thorough review of procedures to identify any adverse operational impacts





4, 5. Combustor for one of the two distillate-only peakers seems so "basic" (left) compared to the DLN-1 dual-fuel combustor serving GT 1B (right)



6. Combined-cycle flow diagram is valuable for details of a vertical, forced-circulation HRSG design no longer used

associated with the new emissions requirement.

What it found was that the steam turbine could not provide sufficient extraction steam to meet the 42-ppm limit on all engines operating simultaneously at full load. The optimal way to address this situation was to convert GT 1B's diffusion combustion system to DLN-1, the OEM's dry low-NO_x offering (Fig 5).

The available extraction steam flow then would be sufficient to allow continued operation of GTs 1A and 1C using the original diffusion combustion system. Note that conversion of GT 1B to DLN-1 required that the engine's Speedtronic Mark II be replaced with a Mark V control system to provide the additional functionality needed to implement the low-emissions solution.

Winkler recalled Stony Brook's DLN-1 retrofit as the first such conversion in the industry. He proudly reflects on the plant's role in the commercialization of DLN technology.

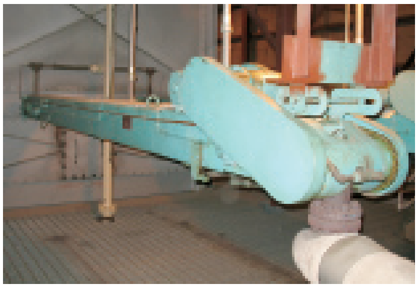
The plant manager then went backwards in time and discussed other upgrades implemented in the years between the conversion to dual fuel and the DLN retrofit, further attesting to the plant's role as an industry leader. These included the installation of Nimonic transition pieces and inlet guide vanes (IGVs) made from Carpenter 450, transition to blunt-edge directionally solidified first-stage buckets and GTD 222 nozzles, etc.

Corbiere and Winkler said the plant's engine parts have been reliable and durable over the years, due primarily to a first-rate maintenance program. GT 1B reached the OEM's declared limit of 5000 starts (only 64,000 operating hours) in 2008 and its rotor was replaced during an outage at the end of that year. The combined cycle's other two gas turbines are closing in on 5000 starts. MMWEC will assess having GE inspect the original 1B rotor, which may result in the OEM certifying the rotor for additional service if all criteria are satisfied.

This could set a precedent for owners of long-lived GE frames. When the OEM first issued its lifetime limits for starts- and hours-based machines, the supplier said it would only consider hours-based rotors for life extension based on inspection results. The manufacturer's initial position was that 5000 starts constitutes end of life.

Important to note here is that the Stony Brook 1A-C GTs were hours-based early in life, running upwards of 4000 hours annually for a few years. Since then, maintenance has been conducted on a starts basis.

The peakers (GT 2A and 2B) have only about 2000 starts and fewer than 6000 hours on each of them. There are plenty of spares for these machines because MMWEC refurbished original parts from the combined-cycle engines when they were upgraded. Stony Brook is blessed with an abundance of storage space,



7. Sootblowers were standard on GE HRSGs burning liquid fuel

8. Portable wash skid cleans combined-cycle turbine compressors semiannually, peaker compressors annually

made possible by the generous supply of retired (and empty) munitions bunkers.

Next on the schedule was a facility tour. But before leaving the office, Winkler reviewed with the editors a flow diagram for the combined cycle (Fig 6). The drawing was particularly valuable for understanding how the plant's heat-recovery steam generators (HRSG) work. The vertical forced-circulation unit was designed and manufactured by GE. As the diagram shows, it looks nothing like the horizontal natural-circulation HRSG preferred today for US combined cycles and cogeneration plants with frame engines (Fig 7).

Discussions with users over the years suggest that GE HRSGs were a nuisance at some plants, but Winkler said Stony Brook's were virtually problem-free. He couldn't recall more than perhaps a total of six tube leaks in the three boilers over three decades of service. Bypass dampers allow the combined-cycle's GTs to start and ramp quickly, Winkler continued, and the HRSGs' forced-circulation design allows them to rapidly attain thermal equilibrium. For more on this type of boiler, access www.combinedcyclejournal.com/archives.html, click 2Q/2009, click West Phoenix on the cover and scroll to p 151.

Winkler talked about the plant's maintenance practices during the walk-around, enabling the editors to gain the insights needed to conduct a meaningful interview on Stony Brook's controls upgrade project—the focal point of the visit. Here are some bullet points from the tour:

- Engine borescope examinations are conducted frequently by plant staff and annually by a third-party services supplier. Winkler believes borescope inspections are critical to avoiding unwanted "surprises."
- Maintenance of the inlet-air house is relatively simple because of the clean environment. Pleated fiberglass filters still are retained by the metal frame installed when the plant was built. Plant staff conducts periodic checks for air leaking by the filters, or entering downstream of the filters, patching holes and replacing defective filters as needed. All filters are replaced on a nominal six-year interval. Winkler said this interval was optimal based on the life of filter material and compressor cleanliness.

Winkler paused for a moment in a cool, quiet location on the deckplates to talk about management's philosophy and the capabilities of plant personnel. "We don't let things go," he said. "Anything we find in a borescope or other type of inspection is addressed promptly. Our engineers and technicians are experienced and attuned to preventive maintenance. The plant's safety record testifies to that: More than six years without a lost-time accident. Important, too, is that our personnel have pride of ownership in the work they do.

Most maintenance is handled in-house—even hot-gas-path (HGP) inspections. "We don't have a long-term service agreement with the OEM, Winkler continued. "And when we require specialty contract work, our people typically work alongside the service provider's employees. We don't pass on opportunities to learn new skills and hone existing ones."

As the tour continued, Winkler contributed these thoughts:

- No online compressor water washing is necessary. Offline washing is done annually for the peakers, semiannually for the engines serving the combined cycle. Plant staff made a portable wash skid for the purpose (Fig 8).
- Stony Brook has not had the varnish issues that have plagued some other plants. Winkler attributes that in part to constant attention to lube-oil cleanliness. Staff built a couple of "centrifuge on wheels" skids (Fig 9) to operate on each engine's sump one week out of six.

  Winkler recalled only one varnish incident in plant history. It occurred in 2005 on a peaker. Plant did a chemical clean using the existing oil, changed filters until they were clean, flushed with virgin oil, and then refilled the engine's 2700-gal sump (one sump serves the gas turbine, generator, and hydrogen seal-oil system).

9. Varnish issues have surfaced only once in the plant's lifetime. Centrifuge cleans oil on each unit for one week in six

10. Lube-oil filters took up too much room in the dumpster for wastes requiring special handling, so plant personnel made a special compactor to reduce both volume and disposal cost

11, 12. On a hot, dry day fogging can boost engine output by about 5 MW. Both Caldwell (left) and Mee systems (right) serve Stony Brook

A practical idea that the staff developed to reduce the volume of oily waste is shown in Fig 10. The compactor squeezes discarded filter elements to about a quarter of their size to save space in the dumpster.

- The plant installed foggers in the late 1990s to squeeze more power from its engines. Systems from both Caldwell Energy Co, Louisville (Fig 11), and Mee Industries Inc, Irwindale, Calif (Fig 12) were purchased. Power boost can be as high as 5 MW per engine on a hot dry day.
- Water and steam for NO_x control, plus water for fogging, contribute to a significant makeup requirement. City water is deionized onsite by two 350-gpm makeup treatment trains. Cation, anion, and mixed-bed demineralizers are incorporated in each train.

GT control system replacement

It's a tough job managing a powerplant in these days of deregulated generation, independent grid operators (ISOs), tight emissions control, etc. There's really little margin for error the way generators are dispatched and paid for their services. Missed opportunities can mean a serious shortfall in revenue. The job becomes significantly more difficult when equipment ages and becomes unreliable, and is no longer supported by the OEM.

However, the marketplace and technological expertise of MMWEC staff have enabled Stony Brook to keep pace with today's challenges. Winkler said management understands that equipment must be upgraded and replaced for the facility to maintain its value. Replacement of the GT control systems is one example.

The plant manager explained that a significant amount of revenue comes from the ancillary services Stony Brook provides—specifically capacity, availability, and black start. In one of the shoulder months, Winkler continued, you may be called only a couple of times to deliver power. A failure to start would result in financial penalties.

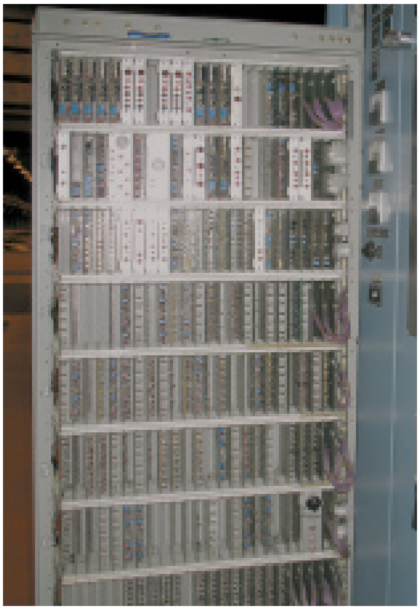
13. Speedtronic Mark II control cabinets rest on skids awaiting a buyer

14, 15. Hardwired cards galore in the Mark II, from the back of the cards (above) and front at right

MMWEC bids the two peakers into the ISO's 10-min forward reserve market with a critical "10 minutes from dispatch signal to base load" requirement. These units are audited by the ISO for compliance at each startup. Winkler shared with the editors a couple of the "report cards" (called Resource Performance Reports) it received.

One such report for a GT 2A start one day last May showed unit status minute by minute. The target was 65 MW within 10 minutes. First eight minutes there were zeroes in the output column, by the end of the ninth minute output was 22.7 MW. At the end of the 10th minute, the number was 65.1 MW. Winkler said they actually achieved the target in about nine and a half minutes. Not much room for error.

A green box with "PASS" in it was at the top of the report. Had the unit not met the target, there would have



16-18. New control cabinet for peaker 2A is at left. It exactly fits in the space remaining after removal of the Mark II cabinet. Note the touch-screen operator interface. Down the aisle is the control cabinet for GT 1A with no screen. Photo in middle shows how efficient PLC-based control systems are in terms of electronic hardware and wiring. At right, the bottom of the Mark V cabinet for the DLN-1 equipped GT 1B reveals considerable clutter compared to the PLC-based control system

been a red box with "FAIL." Get two "FAILs" and your reserve revenue suffers dramatically. Also, the unit must pass an ISO-New England audit to re-establish its 10-min capability and associated revenue.

Winkler said that with the Mark IIs, Stony Brook operators weren't confident they'd make the contract output within the 10 minutes when called upon. Something always seemed to be failing. For example, the multi-voltage (15/28/5) power supplies needed for the Speedtronic II (Figs 13-15). Plant technicians couldn't find new ones anywhere; rebuilds were available, but not reliable. This forced re-engineering of control panels with multiple power supplies.

This scenario certainly is not unique to Stony Brook. Relentless cost-cutting industry-wide, demanding power contracts, suppliers withdrawing support for legacy controls platforms, and a labor pool growing less experienced by the day often leaves plant owners but one option: Replace.

Nolan

RFQ. Half a dozen vendors responded to the public RFQ prepared by the utility with assistance from Pond and Lucier (PAL), Clifton Park, NY. MMWEC and PAL developed what essentially was a performance spec, thereby allowing respondents the flexibility to offer creative solutions. GE and Innovative Control Systems Inc (ICS), Clifton Park, NY, were among the bidders. Critical in the selection process was having absolute confidence that the successful vendor would provide the functionality required and execute the project on schedule. References and experience were particularly important.

The ICS solution had a high degree of transparency because it relied on PLCs and other control system components from Rockwell Automation Inc, Milwaukee, a unit of Allen-Bradley. This equipment is used extensively in many process industries, as well as power, and replacement components are readily available. Many controls integrators have deep experience with Rockwell equipment and software.

ICS was awarded the contract based on its experience with similar upgrades for water- and steam-injected dual-fuel Frame 7 engines, plus cost, schedule, etc (Sidebar 2). There was no foot-dragging on this project: The spec was developed within a month, bids were returned by the end of the next month, bids were evaluated within a month, and the award was made June 30, 2009. Physical work started September 19 and the project was completed on November 10. No more than two machines were out of service at any point during the project, according to ICS President Pat Nolan.

ICS's proposal was for the replacement of the legacy Mark IIs on GTs 1A, 1C, 2A, and 2B with state-of-the-art ControlLogix PLC-based controls that included the following capabili-

2. Emerson Process Management acquires ICS

Pittsburgh-based Emerson Process Management, Power & Water Solutions acquired ICS on June 30, 2010, exactly one year after the company was awarded the Stony Brook controls retrofit project.

Emerson is well respected in the electric power industry for its Ovation™ expert control system, perhaps the most popular upgrade solution for WDPF-equipped Westinghouse gas turbines. The Westinghouse Digital Processing Family of controls was standard on the storied company's engines installed before Siemens AG purchased the firm.

Bob Yeager, president of Emerson's Power & Water Solutions division, said that ICS's turnkey turbine-control retrofit solutions—including planning, engineering, configuration, installation, and commissioning—complements Emerson's expertise in turbine condition monitoring and protection systems, instrumentation, analyzers, and valves.

President Pat Nolan, who founded ICS in 1991, said the company has completed more than 300 turbine-control retrofits worldwide on GE, Siemens, Pratt & Whitney, Alstom, Rolls Royce, and Solar engines—among others. ICS had about three dozen employees at the time of the acquisition, including several in the field.

ties: (1) operation on gas and/or liquid fuel, (2) simple- and combined-cycle operation (the Intermediate Unit's GTs are equipped with bypass dampers and can operate simple cycle if necessary), and (3) NO_x steam (GTs 1A and 1C) and water injection (GTs 2A and 2B). New vibration and flame sensors, automatic synchronizer, and redundant electronic overspeed were included as part of the work.

Control system redundancy was another option considered, but the value proposition did not meet MMWEC's investment criteria. However, the utility decided in favor of redundant communications systems and an engineering workstation. Winkler said ICS solved several long-standing issues associated with the Mark IIs, integrating several new features that enhance the performance and value of Stony Brook.

New panels. As part of the project, ICS prefabricated completely new cabinets for the control systems serving each engine. They had the same overall dimensions as the existing Mark II cabinets. This enabled a complete factory test before delivery to the plant and quick, trouble-free installation. The panels for the two peakers each have an industrial HMI touch-screen operator interface for engine control and monitoring (Figs 16, 17). Screens for the Intermediate Unit's turbines were integrated into the existing combined-cycle board (Fig 18). The screens communicate on a redundant Ethernet network to the PLC controller. Other features incorporated into the operator interface are listed in Sidebar 3.

Nolan said that ICS assigned its most experienced Frame 7 personnel to the project, including Project Manager Parke Brown, VP Engineering Lorcan Roche, and Installation Engineer Beshoy Sawriss. It also developed a sophisticated interactive model of the Stony Brook controls for acceptance testing and training. The factory acceptance test was conducted in the ICS conference room, which is only a 90-minute drive from the plant. Training was conducted for operators and technicians at ICS, MMWEC, and Allen-Bradley facilities.

MMWEC personnel handled loop checks, functional verification of protection, etc—essentially the same things that you would do in any control-system commissioning. Winkler beams with pride when discussing this work. "Fast track," he said "because of our intimate knowledge of the plant and its equipment. Functional checks took about three days; operational checks of various operating conditions, startups, and shutdowns perhaps another three days. And we did the tuning." Typically it took a


Roche


Brown


Sawriss

3. Auxiliary screens facilitate operation

The following are some of the screens provided, in addition to the HMI unit graphic control screens, to facilitate gas-turbine operation:

Water wash. Allows initiation of an off-line water wash and provides turbine protection during the washing process.

Ignition transformer screen allows the operator to test spark plugs by selecting an on-screen push-button.

Online fuel transfer (oil to gas and gas to oil) shows valve positions, fuel-flow percentage, and progress of fuel transfer.

Auto/manual synchronization. A synchroscope with a manual/auto selection available.

Startup check screen shows signal name and logic signal of all that is preventing the engine from starting.

Trip screen shows signal name and logic signal for all turbine protective trips.

Overspeed test allows operator to manually select either electrical or mechanical overspeed. Buttons are provided on screen to abort test, raise and lower speed, etc.

Counter/timers include total unit operating time, distillate-/gas-fired times, emergency trips, total starts, fast starts, peak fired hours, etc.

Wheel-space, exhaust, bearing, and generator RTD temperatures.

Hydrogen purity.

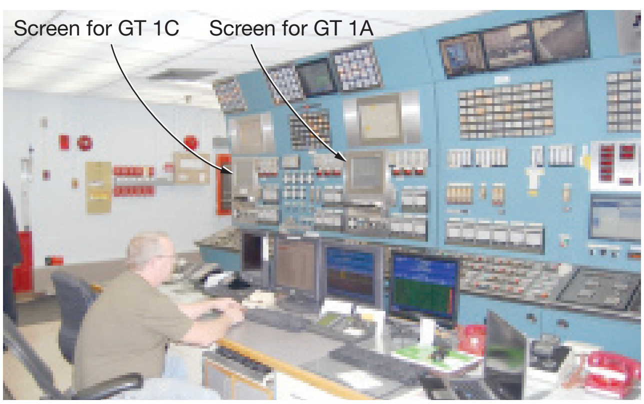
Seismic vibration.

Water injection status and valve positions; plus, the ability to stop/start water injection.

Steam injection status and valve positions; plus, the ability to stop/start steam injection and to view CEMS data.

Calibration screen allows technicians to calibrate gas valves, inlet guide vanes, and fuel-oil bypass valves.

Motor status. Operational status of both ac and dc auxiliary motors is shown on one screen.



19. Operator board for the combined cycle reflects the quality work done by ICS integrating new screens into the existing control panel without changing its appearance

20. Exciter controls for the gas turbine generators were replaced by ICS as part of its workscope; plant staff installed new hydrogen control cabinets week to certify each engine for operation, a process that became easier as time went on.

Experience. When the editors visited Stony Brook, operators had accumulated about six months of experience with the new controls. Winkler said that staff embraced the new system. It provides much more information than the Mark II did for decision-making and work was ongoing to customize graphics and data presentation to facilitate operations, he said.

Startups are much less stressful. The peakers now are up and running at dispatch output within about eight and a half minutes, about a minute faster than was possible before the upgrade. "That's huge," Operations Supervisor Corbiere said. One thing that's critical for achieving a 10-minute start is to purge on unit shutdown so that no purge is necessary on the next start. Control logic assures that on a failure to fire the engine can't be *restarted* unless it is purged beforehand.

Two more projects completed during the control system upgrade project were (1) replacement by ICS of legacy excitation controls serving the four GTs with Basler Electric Co's (Highland, Ill) DECS-400 static excitation system, and (2) upgrade by MMWEC staff of the H_2 control cabinet (Fig 19).

Nolan said the DECS-400 is designed for retrofit applications to supply saturable current transformer (SCT) control winding current to the existing SCT/power potential transformer (PPT)-type exciter. The system, he continued, uses the latest power semiconductor components and controller to deliver accurate and highly reliable dc current to the SCT control windings. The rectifier is supplied on a prewired subpanel and the controller section mounts nearby. Both were installed in existing cabinets.

One final note: Winkler says the Mark V control system for GT 1B, which was reconfigured for DLN operation, will be replaced with PLC-based controls during the March 2011 outage by ICS. The new control system will maintain common hardware, functionality, and software with the other units. Of course, modifications will be required for the additional I/O associated with the DLN system—including additional pressure transmitters, water-injection flowmeters, and flame detectors. Software changes for the DLN-1 control algorithm also will be necessary. CCJ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Don't accept poor starting reliability

By Brent A Gregory, Creative Power Solutions

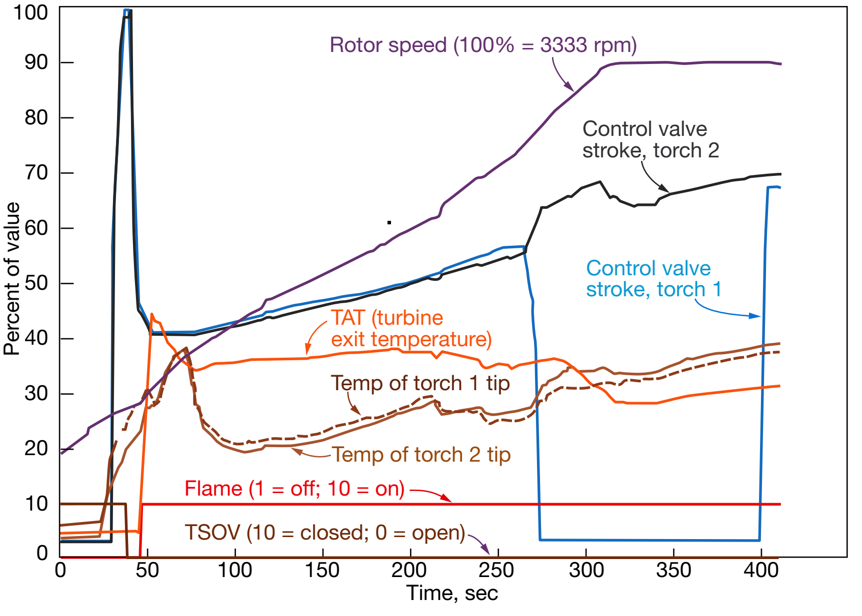
Some power producers want to believe that gas-turbine-based generating facilities don't require a rigorous engineering effort at the design/specification stage of a project. Given that the track record of gas turbines for land-based generation service industry-wide is excellent, and that GTs are "standard" factory-assembled machines, it's no wonder that executives who majored in business and finance think buying a gas turbine is not much different than buying a new corporate limo: Sign the papers, pay, and you're ready to go.

But the "standard" engine often doesn't quite match actual site and operating conditions and, consequently, the new plant may not meet the owner's expectations regarding starting reliability, availability, efficiency, etc—critical factors in the competitive generation business. It's rare that a modest investment in engineering and hardware improvements can't correct the situation. The experience of the General Electricity Co of Libya (Gecol) that follows is a case in point.

The utility's GT fleet includes 23 Alstom machines—including these models: 13D, 13E1, 13E1M, 13E2MXL, and 8C. One of its combined-cycle plants, a facility with three 2 × 1 power blocks and equipped with distillate-fueled 13E2 engines, faced recurring problems during wintertime starts. It turned to Creative Power Solutions (CPS) for a root-cause analysis and permanent solution (Fig 1). Note that Libya, like most Middle Eastern nations, does not release the names and locations of important industrial facilities.

For readers unfamiliar with the 13E2, it is a robust frame engine with a 21-stage compressor, five-stage tur-

1. Libyan combined-cycle plant has three 2 × 1 power blocks. First four Alstom 13E2 gas turbines were installed in 2001, the third block five years later



2. Successful startup, mapped here, often was elusive because of ignition issues bine, and a 72-burner annular combustion system. Last has two ring-type fuel manifolds, each with 36 burners. Arrangement of burners is such that there's one located every 5 deg around the combustion chamber. The OEM claims this design assures even temperature distribution and avoids what it considers problem zones in competitive can-annular systems—such as cross-firing tubes and transition pieces.

The Libyan 13E2s have two ignition torches located 120 deg apart. They are ignited electrically and operate on bottled gas; flame is supported with air from the instrument air system.

CPS engineers began the project by examining data provided by Gecol for both successful and failed starts. Based on this work, hypotheses were put forward and an action plan developed to test the hypotheses and identify possible solutions. Next, the preferred solution would be implemented on one engine and, after validation, would be installed on all six 13E2s.

How the engine is supposed to start (follow curves in Fig 2). First steps in a successful start: The ignition sequencer lights the ignition torch and later presets the oil control valves to the system filling stroke. When the flame is stable, as indicated by an increase in torch tip temperature, the trip shut-off valve (TSOV) opens and oil fills the system up to the sector (pilot) valves.

After a timed delay to fill the system, control valves go to ignition stroke, the burners ignite, and monitors detect the main flame. Then the torch is shut off and its tip temperature drops.

That's the plan. But analysis of startup data revealed the following scenarios which caused or contributed to the failed starts:

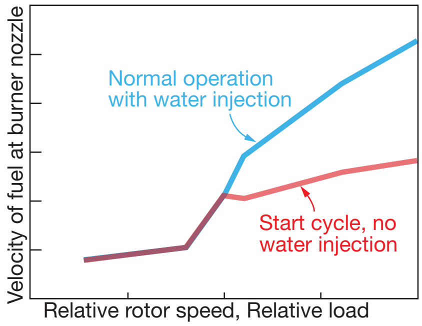
- Ignition pilot flame either did not ignite or failed after ignition.
- Combustor ignited and the turbine exhaust temperature (TAT) rose to the alarm limit, acceleration dropped below its limit, and the engine tripped.
- Combustor ignited and operation was normal—that is, until the TSOV closed (data offered no clues as to why this happened) and the engine tripped on "no fuel."
- Combustor ignited and operation was normal—that is, until the flame monitors no longer saw the flame (weak signal) and the engine tripped on "flame-out."

Several hypotheses proposed for the various startup failures observed were investigated in detail by analyzing the following:

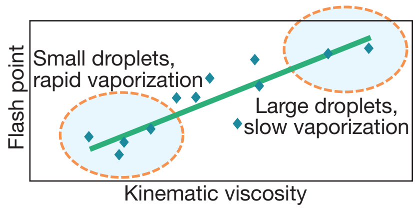
- Fuel properties.
- Operating conditions.
- Ignition torch tests.

Here's what engineers learned:

1. Low-quality atomization of liquid fuel during engine startup.
2. Wide variability—36 deg F—in the flash point temperature of the light fuel oil burned.
3. Ignition torches produced a weak flame at the established operating parameters.
4. Rapid depletion of bottled pilot gas caused a weak torch flame during startup. (Perhaps the gas bottles were too small or were not being refilled fully.)



3. Fuel velocity was low on startup making proper atomization virtually impossible



4. Small droplets of fuel produced by good atomization vaporize quickly

The details

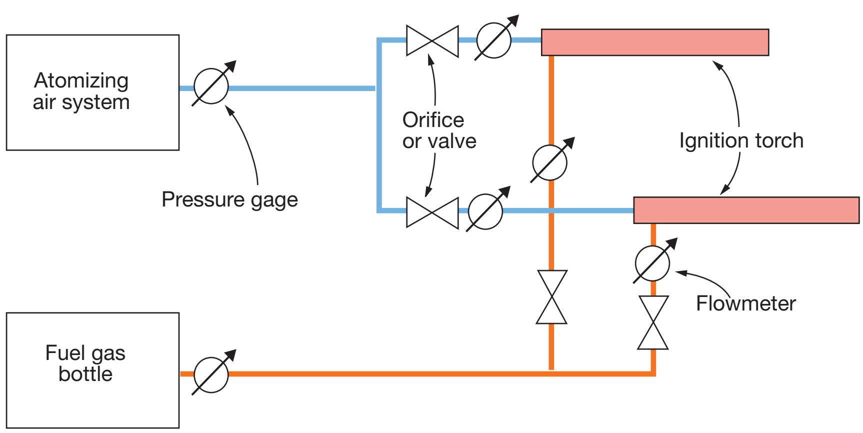
Fuel nozzles for the Gecol GTs are designed to inject two fluids simultaneously: distillate and water for NO_x control. A drawback of this arrangement is that during ignition, NO_x water is not used and the velocity of injected fuel is low, which is conducive to poor atomization (Fig 3).

The large droplets of fuel resulting from poor atomization vaporize slowly and mixing of the oil vapors with air likewise is poor. Such conditions produce an erratic flame which can self-extinguish. A strong pilot flame can help assure reliable ignition in such situations.

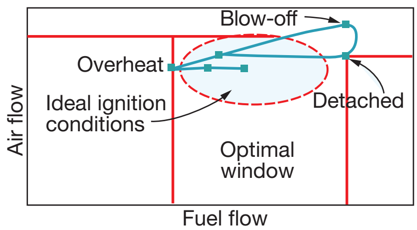
Engineers thought another reason for the failed starts might be high flash-point temperature, so they analyzed distillate samples from many shipments for viscosity and flash point. Fig 4 shows that high-flash-point fuels also have high viscosities and, therefore, are more difficult to atomize than low-flash-point/low-viscosity oils. Variability in flash-point temperatures across the samples was 36 deg F, confirming in the minds of investigators that high viscosity was the underlying reason for at least some failed starts.

To sum up, the CPS investigators concluded that the primary reason for low starting reliability was poor ignition caused by weak gas pilot flames and poor atomization. The ideal oil for startup, they agreed, would be one with a low viscosity to achieve fine droplet sizes during atomization and a low flash point to facilitate ignition. Also that the pilot flame must be strongly "attached" to its lance and be sufficiently hot to vaporize and ignite all possible oils delivered to the plant.

Another benefit of prompt ignition and complete combustion during startup is the elimination of oil residue in the combustion chamber from failed starts. When that residue ignites during a successful start the additional heat may trip the unit on "high TAT."



5. Test apparatus installed by CPS engineers was simple, effective



6. Flame conditions are shown for various air and fuel flow rates using a single ignition torch; no orifices were installed in the supply lines. Best conditions are within the dashed ellipse

The solution

Obvious from the engineering evaluation was that igniter flame strength had to be increased to improve starting reliability. A more robust flame would help even large oil droplets vaporize and ignite quickly. A fully instrumented test rig that would allow CPS engineers to vary air and gas flow to one engine's ignition torches was assembled in the plant workshop (Fig 5).

First step was to identify the optimum flow conditions, with no orifices installed, using the flowmeters on both the air and gas lines. The data gathered provided the basis for quantitative analysis to determine the optimum operational envelope for the igniters. The parameters used to indicate flame condition included the following:

- Torch metal temperature. A thermocouple was used for this purpose.
- Combustion-zone temperature. Measured by a thermometer to assess the impact of gas-flame radiation on fuel-oil vaporization.
- Flame strength. A small-diameter, high-velocity jet of compressed air was blown across the flame to qualitatively determine its stability/strength. Photos were taken during the tests at various operating conditions to record visual observations.

Mapping of test results identified the air and fuel flows that produced both high flame strength and temperature (dashed oval in Fig 6). This information was verified as suitable for conducting a full-scale proof-of-concept test on one of the station's GTs with the expectation of success.

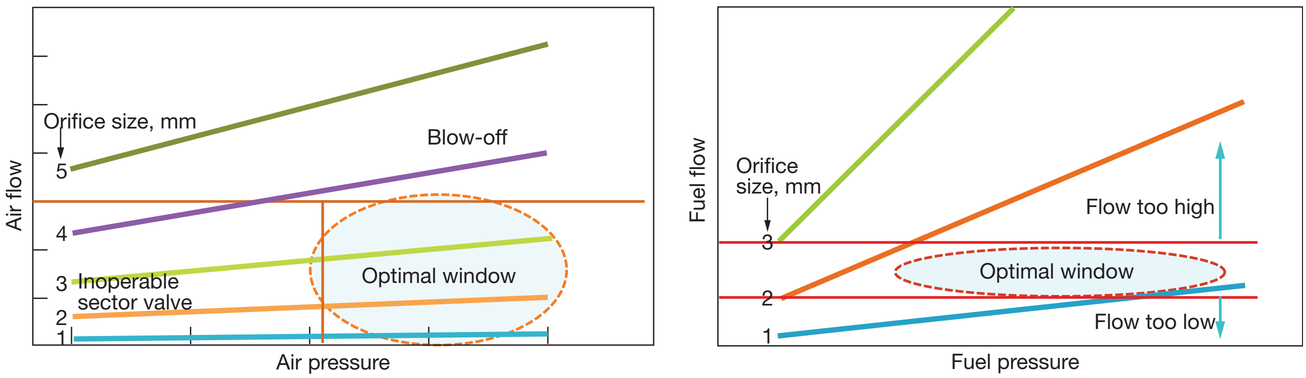
With an optimum operating window identified, engineers conducted a quantitative analysis to demonstrate the importance of air and gas throughput on flame strength. This work was done by calculating flow rates for different orifice sizes based on air and fuel line pressures. Plots for theoretical air and fuel flow rates as a function of line pressure and orifice size is shown in Figs 7 and 8, respectively.

In Fig 7, the ellipse defined by the dashed line presents the optimal window for air flow. It was determined using the minimum air pressure expected from the instrument air system—about 70 psig—and the blow-off point for the igniter flame, as determined during the workshop tests and plotted in Fig 6.

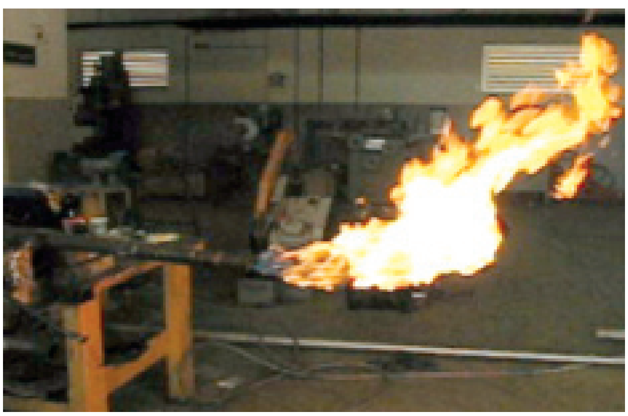
The takeaway from this effort was that an orifice in the air line of 4 mm or larger is undesirable. Further, that use of a small orifice (1 mm), as suggested by the OEM's design criteria, also is not in your best interest.

Optimal window for fuel flow revealed that a moderate orifice size was the best option—too small and flame temperature would be too low, too large and the flame would blow off.

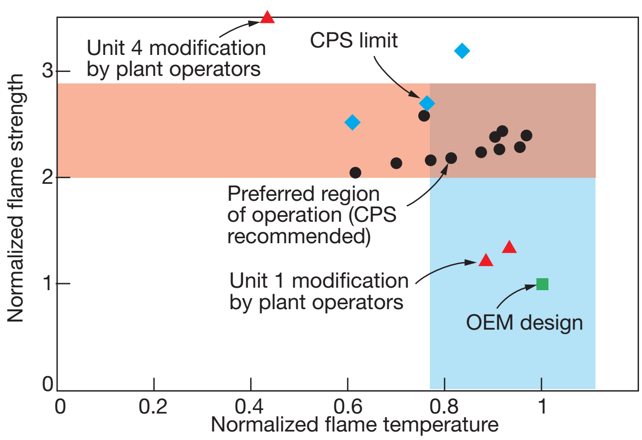
The ignition flame produced when using OEM-recommended orifice sizes in the gas and air lines is too lazy (Fig 9). Modest enlargement of



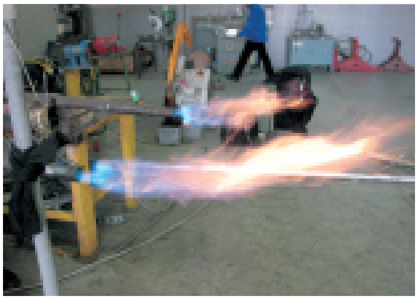
7, 8. Dashed ellipse shows the optimal window for air flow (left), fuel flow (right)



9. Ignition flame produced using the OEM's gas and air orifice settings is much too weak to achieve a high starting reliability on oil



10. Operating in the preferred region (upper right) assures high starting reliability



11. Ignition flame using orifice sizes recommended by CPS provides the thrust needed for successful starts

the fuel and air nozzles by the plant's operations team improved flame strength somewhat, but not enough for the required task.

Orifice sizes for the gas and air lines suggested by calculations performed by CPS engineers were then tested using the engine ignition torches. Stable flame conditions were obtained in the region marked in the upper right of Fig 10.

The stability of a flame depends on its thrust: The higher the thrust, the more heat available to vaporize the liquid fuel. For a given torch, thrust is increased by boosting the total flow of gas and air through the ignition system. The OEM ignition system performed poorly at this plant because the fuel did not meet the manufacturer's spec and there was insufficient gas to create a strong flame.

Use of orifice sizes specified by CPS created the flame shown in Fig 11. Use of these orifices on all six engines restored starting reliability to fleet-wide numbers. All engines started on the first attempt. CCJ

Brent A Gregory (brent.gregory@cpsusainc.net) is president of Creative Power Solutions' US operations, headquartered in Fountain Hills, Ariz; the company also has offices in Switzerland and the UAE. CPS has a broad clientele: it works with utilities to solve complex problems affecting turbomachinery and steam generators, with OEMs to help develop equipment upgrades and next-generation hardware, and with government to provide strategic thinking on future technologies—such as gasification.

CPS's executive team has over a century of engineering/management experience with engine manufacturers Rolls-Royce, GE, and Alstom, and Honeywell and Combustion Engineering.

Sharing knowledge globally

The HRSG User's Group is well known to readers as the "go-to" organization in the US for information on heat-recovery steam generators and other Rankine Cycle equipment used in combined-cycle plants. The group meets annually and attracts about 350 participants to its conference and exposition. Some attendees come from nations outside North America, but not many.

So Chairman Bob Anderson and Dr Barry Dooley of Structural Integrity Inc decided to do some missionary work (Sidebar 1). Their first off-shore conference was held in Brisbane, Australia, last December, and coincided with the launch of the Australasian HRSG Users Group (AHUG). There were over 50 attendees at the two-day meeting, half employed by owner/operators of generating assets powered by gas turbines (Sidebar 2).

Not surprisingly, most of the issues faced by the AHUG participants are the same as, or similar to, those encountered in North America. The meeting summary that follows is based in large part on notes taken by David Addison, principal, Thermal Chemistry Ltd, Horsham Downs, Hamilton, NZ, who was representing CS Energy, a Queensland government-owned corporation and one of Australia's top electricity suppliers. Its stations can generate more than 3000 MW, relying on a mix of coal, natural gas, and landfill gas.


Addison

Program highlights

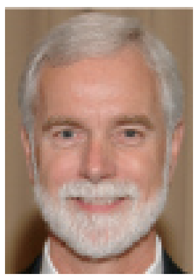
The meeting offered a mixture of focused open-discussion periods separated by prepared presentations—much the same format as the US conference. Discussion topics included heat-transfer components and pressure parts; cycle chemistry; piping systems; ductwork, dampers, stacks; materials issues, flow-accelerated corrosion; risk-based inspection; life-cycle costs.

Anderson got the group's adrenaline flowing quickly by opening the conference with this question: How many attendees have experienced tube failures in their HRSGs? About a half-dozen hands shot up immediately. But judging from the ensuing discussion on evaporator and superheater tube failures and tube-to-header failures in economizers, many others in the room could have raised their hands. It can take time for conservative engineers to get used to Anderson's style.

The chairman may walk miles up and down aisles during the day—microphone in hand—firing ques-

1. Meet the AHUG leadership

AHUG leaders Robert W Anderson and Barry Dooley, PhD, DSc, are among the world's leading experts in the design, construction, operation, and maintenance of heat-recovery steam generators and other Rankine Cycle equipment.


Anderson

Anderson leads Competitive Power Resources Corp, Palmetto, Fla, a consulting firm he established in 1994 to assist clients in the management of powerplant assets (anderson@competitivepower.us). He is a 33-yr veteran of Florida Power Corp/Progress Energy, where he served as a plant manager of several thermal generation assets and later as the corporation's fleet-wide HRSG solutions provider. Anderson stands tall among the industry's technical discussion leaders.


Dooley

Dooley is one of the world's foremost authorities in the fields of powerplant water chemistry and metallurgy (bdooley@structint.com). He is best known to readers for his work in improving both cycle chemistry and the reliability of HRSGs, and in reducing boiler tube failures and flow-accelerated corrosion. Educated in both the UK and Russia, Dooley has authored or co-authored more than 260 technical papers as well as books on boiler-tube failures, steam turbine damage mechanisms, and FAC. He is a senior scientist at Structural Integrity Associates Inc.

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Attend The Premier Combined-Cycle/Cogen Conference and Exposition tions, offering solutions, keeping everyone involved. Active participation is critical to the meeting's success and Anderson is expert at keeping attendees focused on the subject at hand. If the group becomes lethargic, he may ask everyone to stand and run through a regimen of in-place exercises to get more oxygen in the collective bloodstream.

Tube failures. Here's a summary of Australasian experience on tube failures from the first discussion session:

- Thermal fatigue common in the area of tube-to-header welds on both the hot and cold ends of the unit.
- Flow-accelerated corrosion (FAC) found in many HRSGs at tube bends.
- Corrosion under insulation found most often in the petrochemical industry where water ingress typically is a major issue. Piping at temperatures less than about 265F is at greatest risk, as are drain lines operated infrequently. One way to prevent drain-line corrosion is to replace insulation with expanded mesh for personnel protection when the drain is active.
- Attendees said root-cause analyses (RCAs) were conducted on most failures, which Dooley applauded as a best practice.
- Users who experienced corrosion of casing seals and have switched to designs that permit flow-through of warm air reported eliminating this nuisance.
- Some attendees reported "infant mortality" of seam-welded tubes. Most often these failures were experienced during commissioning.
- Quenching of economizers attributed to flow starvation during startup because of drum swell generated some discussion. What happens is the economizer acts as a heat sink until steam starts flowing and drum level drops; thermal shock occurs when water flow through the heat-transfer section restarts. Two suggestions to avoid the problem: Establish flow via drains or install recirculation pumps to minimize temperature gradients.

Question from the floor asked by Lester Stanley, HRST Inc, who recently returned to company headquarters in Eden Prairie, Minn, after completing a three-year assignment in Australia: A few HRSGs in North America are struggling with stress-corrosion cracking in carbon-steel economizer tubes—a problem thought linked to the presence of nitrates in gas-side deposits. What has been the experience in Australia?

Only one user reported stress-corrosion cracking in his boilers and that occurred at the bends in horizontal economizer tubes of a refinery HRSG. An RCA had not yet been performed.

Dooley stepped to the podium after the opening discussion period and made the first of his two presentations, this one on trends in cycle-chemistry performance. Here are some industry best practices from that paper:

- Use of amine blends is ill advised.
- Regarding phosphate blends, use only trisodium phosphate.
- Best location for HP evaporator sampling is close to the outlet header of the highest-temperature evaporator tube.
- Keep the steam turbine dry during outages to avoid pitting of turbine blades. For details on how to do this, access www.combinedcyclejournal.com/archives.html, click 1Q/2010, click "Preservation program. . . ." on issue cover.
- Tube samples are important when dense, tenacious deposits are present. Nondestructive examination (NDE) techniques available for deposit analysis are not sufficiently accurate.

Dooley has written extensively on cycle chemistry. For an in-depth look at industry practices, return to the journal's archives and click 1Q/2009 to access "HRSG assessments identify trends in cycle chemistry, thermal transient performance," which he co-authored with Anderson.

More discussion followed Dooley's presentation. One "thread" focused on problems associated with gas-side deposition and fouling in the cold end of HRSGs. A user reported sulfur and rust deposition and was concerned about long-term effects although none were in evidence—yet. Another attendee reported fin corrosion, yet another said airborne dirt was sticking to heat-transfer surfaces which had become coated with oil during construction. Surprisingly, by show of hands, no one was monitoring backpressure.

Next topic: Long-term inspection plans. First user volunteered that past focus had been on pressure parts, but her company was undergoing a philosophical change to a risk-based inspection program for predictive maintenance. Work in progress included identifying what/where to inspect and preparing equipment for ease of inspection.

Another attendee offered that a risk rating system had been developed over time for inspections and replacements of virtually all components. This program melded both the experience of his company and of others. Latter often came from presentations, group discussions, and personal contact at user meetings.

One user spoke about the installation of Riskwise, a risk-based assessment program, at his plant. Expecta-

2. AHUG II, December 7-8

Shortly after this article was written, the Australasian HRSG Users' Group announced a formal structure for the organization as well as the dates and location of its next meeting.

AHUG's mission is to provide a forum for owners, operators, manufacturers, service providers, consultants, and others with an interest in heat-recovery steam generators and associated plant processes and equipment to share knowledge and experiences.

The group is chaired by Bob Anderson, principal of Florida-based Competitive Power Resources Corp; Barry Dooley of North Carolina-based Structural Integrity Associates Inc is vice chair. Other members of the Steering Committee are the following:

- Gary Joy, CS Energy.
- John Rickerby, Contact Energy.
- Lester Stanley, HRST Inc.
- David Addison, Thermal Chemistry Ltd.
- Daniel Cole, Origin Energy.

The 2010 meeting will be held December 7-8 (summertime in Australia) at the Brisbane Convention and Exhibition Centre. Workshops on flow-accelerated corrosion and P91 piping are scheduled for the day after the meeting and require separate registration. For more information, visit www.ahug.co.nz.

tion was that additional NDE would be required on critical steam-pipe welds, etc. Group think was that risk-based assessment is a learning process driven by safety and management concerns.

Diligence and commitment are key elements of any inspection plan. The point was driven home by Chairman Anderson who recalled a shop using a heat-treatment procedure for P22 on P91 pipe bends. This segued into an exchange on the importance of verifying materials during benchmark inspections. Another article in this issue, "P91 commands respect," illustrates the point well.

Dealing with upsets

Thermal Chemistry's Addison offered a series of operational best practices in his presentation, "Major HRSG cycle-chemistry upsets: Practical management steps and avoidance strategies." Addison's suggestions are based on a combination of background knowledge (a bachelor's degree in chemistry and a masters in materials) and 13 years of hands-on experience on the deck plates of combined-cycle, conventional steam, and geothermal plants.

His core message was "be prepared" to deal with a wide range of possible upset conditions, noting that "things can go bad very, very quickly." Failure to respond immediately with the proper solution can be very expensive, Addison stressed.

The chemist/metallurgist's "poster" example was seawater ingress, which can cause significant damage to boilers and steam turbines within minutes. Even repetitive small leaks, he continued, cause cumulative damage over the long term, increasing the likelihood of component failures—boiler tubes and turbine blades, for example.

"While you cannot eliminate all chemistry risk," Addison said, "you can minimize it to a large degree." His recipe for minimizing the risk of a chemistry "disaster" includes good:

- Systems. Clear procedures accessible to all employees.
- People: Operators, chemists, and managers.
- Plant equipment: Online instrumentation, proper dosing, condensate polishers.
- Confidence: Decisions sometimes are required quickly. Empower qualified people to make such decisions.

Contaminated conditioning chemicals—such as ammonia, phosphate, sodium hydroxide, etc—can be a source of cycle contaminants (chlorides, organics, for example). Consider the possibilities:

1. Storage-tank contamination and failure to properly flush new tanks and connecting piping.
2. Use of incorrect dilution water—perhaps raw water in place of demineralized water.
3. Manufacturing errors—use of a wrong chemical or grade.
4. Pump-over errors to wrong tank through contaminated transfer lines.

Contamination often is the cause of a sudden deterioration in evaporator/steam cation conductivity and a drop in pH soon after a chemical delivery. If this occurs, plant procedures might suggest that operators stop the chemical feed, switch to alternative supplies, and/or increase blowdown; or in an extreme case, shut down the unit.

Water-treatment-plant upsets can be caused by the failure of ion-exchange resins; regeneration issues, such as wastes finding their way into demin tanks; membrane failures; tuning difficulties following a maintenance outage, etc.

A sudden change in evaporator/steam cation conductivity and decrease in pH linked to makeup system operation indicates an upset condition. First action should be to check operation of the water treatment plant and dump contaminated water from storage tanks; then consider unit shutdown.

Addison said you can minimize the likelihood of future upsets by reviewing the design of the water treatment plant and making judicious improvements, pre-testing new resins, providing for online analysis of makeup water, improving interlocks, and increasing the level of training for water-plant operators.

A condensate polisher is strongly recommended by Addison for most plants. However, it can be a double-edge sword. When operating properly it assures top-quality feedwater; when not, it can be a source of cycle contamination. Possible issues include (1) leaching of organics because of resin failure, (2) contamination resulting from poor regeneration, (3) incorrect ammonia cycle operation with standard mixed beds, and (4) anionic leaching as a result of running to exhaustion.

Polisher upsets are identified by poor quality of outlet water, elevated evaporator cation conductivity, depressed evaporator pH, and increased cation conductivity of steam. Suggested first response: Shut down the polisher and increase HRSG blowdown. Then consider unit shutdown.

Consider the following to avoid upsets in the future: (1) Tighten procedures for resin testing and commissioning, (2) extend recycle on startup, and (3) establish stringent quality limits for automatic trips.

HRSG contamination from outage activities. Failure to remove waterside debris at the end of an outage can cause tube blockages and resultant overheating failures. Contaminants from boots, NDE solvents, weld repairs, etc, are other concerns.

Elevated levels of silica and cation conductivity in the evaporator, unusual organics, and an increase in steam cation conductivity are indicative of contamination. Suggested corrective action: Heavy blowdown, maintain drum pressure below normal operating pressure until the steam/water circuit is clean, then shut down the unit and dump/flush.

Eliminating contamination, or minimizing its effects, is relatively simple and all about good procedures and discipline. First and foremost, enforce clean internal-access procedures; fill, flush, and dump the HRSG after each outage requiring internal entry; maintain heavy blowdown when the boiler is returned to service until system chemistry is within spec.

Condenser tube leaks happen, which is why a polishers should be designed into the condensate/feedwater circuits of all water-cooled E- and F-class combined-cycle plants. Addison told the group that the risks associated with a condenser tube leak in a plant without condensate polishing are *major*. Even titanium-tubed condensers fail, he reminded.

Cooling water's high concentrations of total dissolved solids are of greatest concern—especially those high in chlorides. Operators must be prepared to respond quickly if online analyzers go "off scale." Unprepared personnel can become confused and delay action necessary to minimize equipment damage. A characteristic of condenser tube failures is the sequential increase in cation conductivity through the cycle. Keep in mind, too, that contamination of steam may be virtually instantaneous because condensate is used for desuperheating.

Recommended response: Blowdown, drop load, increase evaporator pH, stop attemperation, and shut down the unit. Addison said there are two schools of thought on what to do next:

1. Drain the HRSG as soon as possible to remove the contaminants. However, this course of action comes with the risk of "baking in chlorides."

2. Allow the HRSG to cool, ammoniate heavily to form highly soluble ammonium chloride and then drain and flush repeatedly.

Consider chemical cleaning, too, unless damage is so extensive that it is necessary to replace the HRSG. An alternative to chemical cleaning: Restore the unit to normal operation and deal with pressure-part failures as they occur. Automatic unit trips based on conductivity readings are something to think about going forward. So, too, is the installation of a condensate polisher.

Summing up, Addison stressed that poor operating practices and operational mistakes either cause or exacerbate many of the chemistry upsets plants experience. He suggested that each plant conduct a site-specific cycle-chemistry risk assessment and create a living document that provides clear and robust O&M guidelines to mitigate risk. The document should be updated annually or more frequently.

Development of your plant's guidelines should be a multi-disciplined process for best results—one involving inputs from operators, engineers, managers, and chemists. At the end of the process, all participants will know their roles, responsibilities, and decision-making authority.

Perhaps the most important section in your guidelines will be the one with procedures for responding to a cycle-chemistry upset. It should stress the importance of initiating remedial action as soon as possible. Some points to remember:

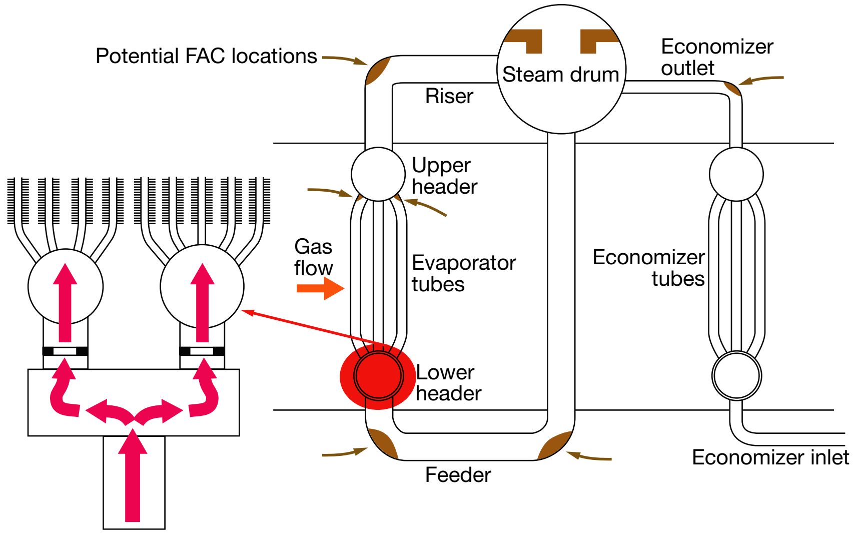
- Blowdown almost always is a good initial response, the heavier the better.
- Reduce load and drum pressure to buy time.
- Protect the steam path and turbine. Halt attemperation and begin steam-turbine bypass operation quickly.
- When in doubt, shut down the unit.

Thermal transients

Anderson replaced Addison at the podium and addressed thermal transients in HRSGs. Much of what he covered can be found in the 1Q/2009 article referenced earlier that he co-authored with Dooley. However, a couple of O&M "pearls" are worth repeating:

- On startup, it's better to let steam temperatures go high rather than over spray. One second of over spray does far more damage in terms of thermal fatigue than the creep damage associated with operating for one hour at a steam temperature above design.
- Attemperator maintenance is important for plants starting daily. Focus on isolation valves, to prevent water in-leakage. The latest edition of the *ASME Boiler and Pressure Vessel Code* requires a drain downstream of the attemperator.

Allan Evans of Origin Energy took his turn at the podium with a presentation on HRSG controls. He opened with an entertaining history of boiler controls from the pneumatics era forward that included vintage photos of Bailey boards. But the real purpose of Evans' presentation was to provide guidelines on HRSG control system arrangement and alarm management. Regarding the latter, he noted that the number of configured alarms per operator has grown from less than 100 in 1960 to about 8000 today—clearly ridiculous. Think of alarms as one



1. Where to look first for FAC attack in your HRSGs. Prime locations are wetted components in the IP and LP circuits where water and/or steam temperature is between about 220F and 480F

area where *less* probably is *more*.

23 skidoo. Anderson started the next discussion session by gauging interest in advanced materials, such as T23. End users have identified problems with T23 and ASME recently issued Code Case 2199 to tighten up its chemistry. Attendees expressed little interest in the subject. One metallurgist recently told the editors, tongue-in-cheek, that the higher number—referring to the industry standard T22—didn't make the material better.

Manway gaskets. The chairman quickly moved to a more practical problem: Sudden failure of steam-drum manway gaskets under pressure. Anderson is familiar with this issue and suggested the following actions to minimize the possibility of occurrence:

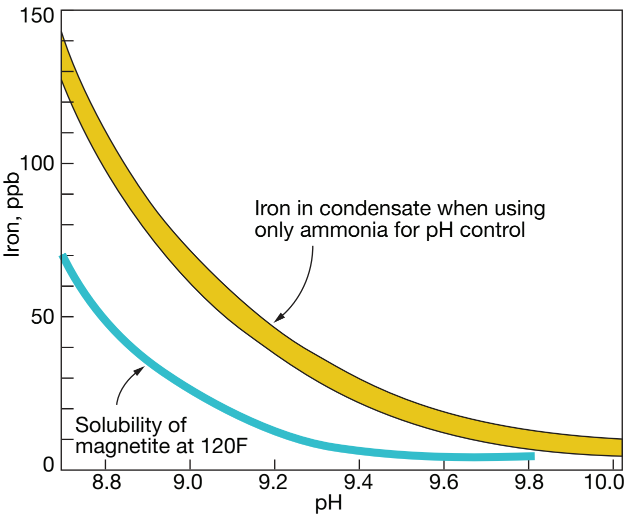
- Be sure the correct gasket material is installed; use OEM parts.
- Verify proper closure and sealing of the drum door before restarting the unit.
- Do not make any change to the drum door that is not approved by the OEM.

91 roulette. The ensuing discussion on 91 material created a buzz. One user said that based on his company's experience, 183 HV (Hardness-Vickers) is the minimum acceptable hardness. Below that creep-life issues emerge. Another attendee cautioned against condemning P91 based on hardness measurements alone; metallographic analysis is necessary for accurate decision-making, he said.

According to the calculator at www.tribology-abc.com, 183 HV is equivalent to 183 HB (Hardness-Brinell). In the article on P91 in this issue (see reference above), Steve Gressler, a metallurgist with Structural Integrity Associates Inc, suggested 190 HB as a lower limit. So, it seems that experts east and west are in general agreement.

Another attendee said he had heard that some plants in the US were considering the replacement of P91 with P22 because of the uncertainties associated with the 91 material. The group agreed that tight 91 specifications and diligent enforcement of those specs were critical to successful application of the material. A suggestion offered: If you run into a problem with P91, seek advice from people and companies with relevant experience. There's no reason

2. What FAC attack looks like in evaporator tubing (A, B, C), lower evaporator headers (D), ACC steam duct (E), and ACC A-frame tubes (F)



3. Iron removal from components in condensate/feedwater circuits—such as air-cooled condensers—depends significantly on pH. Magnetite solubility curve is based on the work of P Sturla as reported in 1973. Iron levels in condensate were measured immediately downstream of a condensate pump by Dooley and J Denis Aspden of Eskom, the South African utility

to repeat mistakes.

No one disagreed with the thought that leak-before-break is valid for P91 external to the HRSG. Anderson picked up the microphone at this point and recommended always shutting down and depressurizing the system in the event water is seen dripping from piping. Only then should you remove insulation. Safety first! A representative of a New Zealand utility agreed and said his company treats all leaks as major until proven otherwise.

The subject of 92 was raised briefly because only one plant owner represented at the meeting had the material installed—T92 tubes welded to P91 headers—and its experience was limited. Oxide formation associated with 92 was raised as a concern because it was not well understood.

Oil ingress into the condensate/feedwater circuit was a subject of interest to plant representatives. Two of the three main contributors to this dialog said they had to chemically clean and flush their HRSGs as a result. Two of the three said the source of oil was a turbine bearing leak, the other said it came from air-blow compressors in use during commissioning.

FAC guru

Dooley's second presentation was on FAC in HRSGs, a subject he could have lectured on for two days. One of the world's top experts on the subject, Dooley began with a simple statement: "FAC involves rapid mass transport, magnetite dissolution, and wall thinning with local conditions becoming more reducing." He stressed that FAC is not a one-time issue and that the cure requires addressing the root cause with a corporate/plant program.

Circuits susceptible to FAC in combined-cycle plants include the feedwater system, deaerator, economizer tubing, LP evaporator tubing, LP drum internals, lower drums in the LP section, and air-cooled condensers. Dooley went on to identify locations where FAC is known to occur in HRSGs and other equipment, showing dozens of photos so attendees knew exactly what to look for when they returned to their plants (Figs 1, 2).

Next he ran through the causes of single- and two-phase FAC and the parameters that influence their occurrence—such as pH, temperature, water velocity, etc—and the benefits of alloying elements such as chromium. Perhaps the most important thing to remember from a Dooley lecture on FAC: Never use reducing agents in your steam/condensate system—not even for layup/storage.

The latest thinking and experience on this subject will be covered in a special report next issue based on the presentations and discussions at the recent international conference, "Fossil FAC," developed and chaired by Dooley and one of his colleagues from Structural Integrity.

Air-cooled condensers. The presentation on ACCs by Ian Richardson of CS Energy was based on experience at a supercritical coal-fired unit, but much of the material disseminated also was applicable to conventional subcritical steam boilers and HRSGs. The big benefit of ACCs is that absent cooling water they facilitate the siting of generating facilities in arid areas. Plus, plants with dry cooling avoid many of the cycle-chemistry risks associated with wet cooling as described earlier.

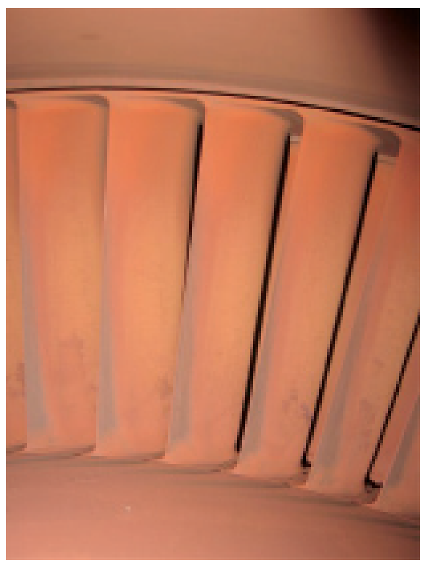
However, ACCs have a negative impact on plant heat rate, and are prone to FAC, air in-leakage, and production of significant amounts of corrosion products because of the huge amount of surface area required to condense turbine exhaust steam.

FAC is something every ACC owner/operator wants to avoid because the metal loss (1) contributes to high particulate loading in condensate filters and polishers and high concentrations of iron in feedwater, (2) is conducive to air in-leakage, and (3) increases the potential for fouling of, and damage to, boiler heat-transfer surfaces and turbine steam-path components (Fig 3).

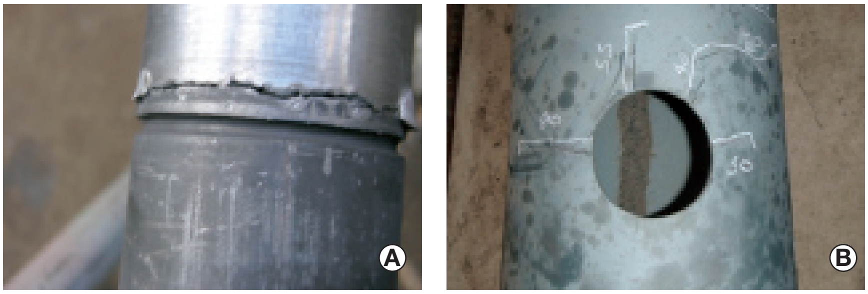
Richardson stressed that tight pH control is critical to minimizing corrosion, which typically is found in the turbine exhaust section, steam ducting from turbine to ACC, and condenser headers and tubes (Fig 4). While the rate of corrosion can be controlled, it's not possible to eliminate it altogether and condensate treatment is necessary. Options include filtration and/or polishing.

Owner/operators wanting to learn more about the operation and maintenance of ACCs, and share their experiences with others, should attend the second annual meeting of the ACC Users Group, September 28-29, at Xcel Energy's Comanche Station in Pueblo, Colo. Contact Sandra Brown, systems chemist, today (sandra.k.brown@xcelenergy.com, 719-549-3784).

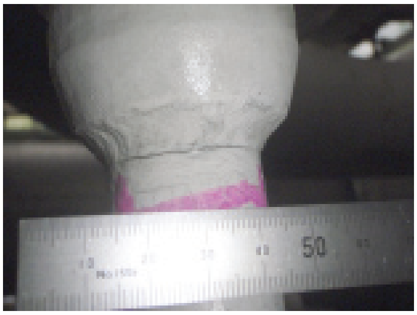
Operating experience. Several attendees from CS Energy's Swanbank Power Station reviewed the plant's experience with its unfired triple-pressure HRSG. The 1 × 1, single-shaft, 385-MW, combined-cycle facility reached 48,000 equiva-



4. Corrosion products are transported throughout the condensate/feedwater circuit as evidenced by deposition on steam-turbine blades



5. Desuperheaters take a beating in many combined-cycle plants. Note cracking of HP nozzle (A) and liner (B)



6. P91 components are not immune from cracking. HP drain line is one example

7. Crack in support saddle for HP drum was repaired during outage

lent operating hours in June 2009 and conducted a 55-day outage. It included the second C inspections for the gas turbine and HRSG, the first B inspection on the generator, and the steam turbine's first IP/LP C inspection. The F-class facility, commissioned in March 2002, operates on both natural gas and coal-bed methane.

The HRSG inspection revealed corrosion both in the back end of the unit and the stack, and cracking of the following components:

- Desuperheaters—HP nozzle and liner (Fig 5); hot-reheat (HRH) piping.
- HP steam-flow venturi.
- P91—HP drains, HRH thermocouple pocket and fixed-anchor-point saddle (Fig 6).
- Casing—HRSG transition immediately ahead of HP superheater 3.
- HP-drum support saddle (Fig 7).

Not surprisingly, perhaps, large-bore bends in the HP and HRH P91 piping were found "soft." The company's position is that parent and weld material must be at least 183 HV. The lowest recorded readings on HP elbows were between 132 and 142 HV.

The soft pipe triggered an immediate and extensive nondestructive examination of HRSG piping. Lifetime implications still are being assessed. Accelerated creep testing is underway and a monitoring program has been implemented. Creep tests are being conducted at elevated temperature for times ranging from 1000 hours to six months. CCJ

Integrating solar, conventional energy resources

By **Thomas F Armistead,** Consulting Editor

"When the sun shineth, make hay" is an ancient proverb recently updated to "make electricity." Combined-cycle (CC) plants are critical to this goal with an innovative approach that augments the heat-recovery steam generator's (HRSG) output with steam generated using solar-thermal energy. One plant has been online in Morocco since May; two others in North Africa and one in Florida will enter commercial operation this year as well.

The solar/CC hybrid, known as integrated solar/combined cycle (ISCC), has been studied and demonstrated for more than two decades, but it is only now beginning to unbolt its training wheels. A variety of technologies using solar-thermal energy for power generation are in the market (sidebar) and the US Dept of Energy and others are investing furiously in research, pilot, and demonstration projects. In May, for example, the DOE awarded $62 million to 13 concentrated solar power (CSP) projects—and that is only the most recent award.

But little if any of it is going for ISCC. Last year, the Electric Power Research Institute, Palo Alto, Calif, stepped into the breach, conducting feasibility studies on augmenting the steam cycles with solar energy for powerplants fueled by both natural gas and coal. EPRI was encouraged by the results.

"Technically, it's very feasible," said Cara Libby, EPRI project manager for the studies. "We have an understanding of how solar plants operate and we don't anticipate any major issues with integrating that steam into either a combined-cycle plant or pulverized-coal plant. The reliability and the availability of the base plant should not be affected by the addition of the solar field."

Two CC plants participated in the feasibility study and case study: NV Energy's Chuck Lenzie Generating Station, a few miles north of Las Vegas, and Dynegy Inc's Griffith Energy Facility near Kingman, Ariz. Collaborating participants were Progress Energy, Salt River Project, The Southern Company, and Tri-State Generation & Transmission Assn. Only NV Energy is proceeding with a demonstration project; Dynegy has sold the Griffith plant.

Martin Next Gen Solar Energy Center

Would it work?

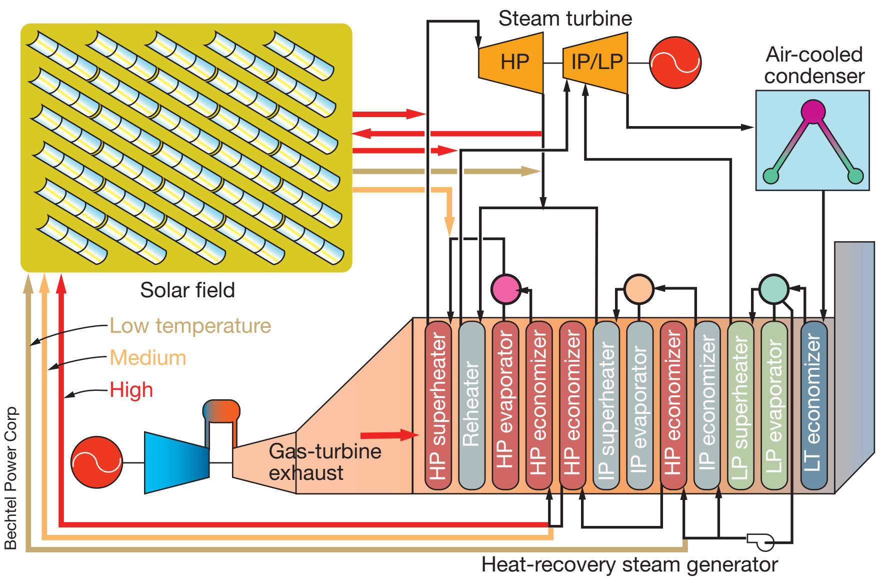
Nevada's Renewable Portfolio Standard (RPS) is ramping up quickly. In 2008 it mandated that 9% of the kilowatt-hours sold by electric utilities in the state come from renewable resources; in 2009 it was 12%. By 2015, 20% of the state's electricity must come from renewables; 25% by 2025.

NV Energy is meeting its requirement in part with a long-term power purchase from Nevada Solar One, a 64-MW CSP plant completed in 2007 in Boulder City by Acciona North America. NV Energy hosted the case study at its 1102-MW Lenzie plant to better understand the potential of solar energy to augment its own system, said Todd Eagleston, director of development for renewable energy.

EPRI listed the key augmentation issues for the case study as:

- Heat balance.
- Water consumption.
- Point-of-steam addition and take-off options.
- Metallurgy constraints.
- Control, ramping, and integration impacts on O&M.
- Blending and control strategies for steam introduction.
- Ideal options for peaking plants versus base load.
- Operation strategies during periods of solar variability.

The case study aimed to determine the integrated solar design that offered the best investment option within the equipment limitations, operational requirements, and reliability constraints, and to provide sufficient information for the plant owners to make an educated decision regarding implementation, according to EPRI.



Legend: HP, High pressure IP, Intermediate pressure LP, Low pressure LT, Low temperature

1. Three ways to integrate thermal energy produced by the solar field and the heat-recovery steam generator based on the temperature of steam flowing from the solar array

Detailed heat- and mass-balance models of the plant were developed to screen and evaluate three solar-steam integration design options: high-pressure saturated steam, high-pressure superheated steam, and intermediate-pressure superheated steam. The HP superheated steam option was selected for more detailed analysis to estimate plant performance on an annual basis. An economic model quantified the changes in plant revenue streams offered by the new operational profile of the plant.

The case study's results were satisfactory, and NV Energy now is in the early permitting phase of the project to integrate solar steam into the combined cycle, said Eagleston. "As early as two years from now, we could have a permit to construct." Construction could take 18 months more, he estimated.

Probably, here's how

The utility has decided on a parabolic trough design for its solar field because "that's a solar-thermal technology that has commercial traction," Eagleston said. Thoroughly tested for many years in California, "it's arguably the only technology that's financeable today, at least in accordance with standard project financing," he added.

In operation, the solar field's heat-transfer fluid is heated to about 750F and directed to a solar boiler, which produces saturated steam at about 700F (Fig 1). The solar steam typically is sent to the HRSG's high-pressure drum, which has approximately the same steam conditions. The two flows, combined in the HP drum, then go through the HP superheater.

Solar thermal integration would add 90 MW or more to Lenzie, which has two 2 × 1 7FA-powered combined cycles (access www.combinedcyclejournal.com/archives.html, click 2Q/2009, click "Lenzie" on the magazine cover). The 600-700-acre field could also add 30 MW to the nearby 484-MW Harry Allen Station, still under construction.

"We are looking at the viability of doing it on both," said Eagleston. Because of the supplementary firing already designed into the plant, "the Lenzie project has a little more 'headroom' in its HRSG," he explained. The idea is to replace with solar energy, the capacity gained by turning on the duct burners.

As a side benefit, the integration of the solar resource also increases the return on the investment for the duct burners, which normally are used only 5-10% of the year to boost generation when the grid price of electricity is high, Eagleston said. When the solar plant's power dips, the duct burners can be turned on to maintain the higher power output required.

The case studies focused on retrofitting combined-cycle plants with solar fields. EPRI now is continuing research on greenfield solar/CC plants. "We've defined a reference plant (CC + parabolic trough) and now we're looking at superheater and reheater design options that would optimize the overall performance of the plant," Libby wrote in an e-mail.

"A preliminary analysis shows that duct firing is likely the preferred option on a capital cost and emissions basis for firming CSP, when compared with simple-cycle gas turbines, natural-gas reciprocating engines, and supplemental firing of standalone parabolic-trough plants. The modeling and parametric studies are nearly complete and we're in the process of reviewing the costs [capital and O&M] to see how the greenfield plant compares with the retrofit plant designs that we've already studied."

Symbiosis

ISCC is a marriage of two generation technologies that have shown staying power over several decades. The combined cycle has been installed in hundreds of powerplants to produce power at high efficiency. Electricity generation using the thermal energy of the sun, commonly called concentrated solar power or CSP, has been demonstrated for decades and has had increasing commercial success in the last 10 years.

Both technologies use a conventional cycle for power generation. Only recently, however, have designers attempted to enhance the combined cycle with solar-generated steam. According to news reports, one such plant entered commercial operation in Iran last year, and Morocco's state-owned utility opened one last spring.

Others are nearing completion in Algeria and Egypt, and should be generating into the grid by year's end (table). Also scheduled for commercial operation this year is Florida Power & Light Co's (FPL) Martin Next Generation Solar Energy Center taking shape near Indiantown, Fla. When completed, it will become the first commercial ISCC plant in the US, but others already are planned.

As with any symbiosis, the hybrid combination of CSP with combined-cycle operation confers mutual benefits. Steam generated with solar-thermal energy boosts the output of the fossil-fueled powerplant without increasing emissions. And combining the CSP plant with a fossil-fueled combined-cycle helps to reduce the high cost of the solar plant in several ways. It saves on permitting costs, it builds a solar plant where transmission capacity is already available, and, most significantly, it saves the cost of a separate steam turbine for the solar plant, which simply "borrows" the combined-cycle's steam turbine.

But cost is still a major impediment

to adoption of solar power technologies. To jump-start the industry, 31 states have established Renewable Portfolio Standards (RPS) or Alternative Energy Portfolio Standards (AEPS), and five others have established goals to encourage utilities to increase the share of power generated by renewable or alternative energies in their retail sales.

These standards and goals are helping to drive the trend to renewable energy, which still cannot compete on price with fossil fuels. They also give the utilities political cover when requesting rate increases to add pricey renewable resources to their mix. Solar augmentation potentially is the lowest-cost option for adding solar power to the generation fleet, according to EPRI. What makes it a particularly attractive renewable option is the fact that solar energy normally is highest when summer loads are peaking.

Integration of solar thermal energy in a fossil-fueled plant also allows the plant to serve as a dispatchable resource with firm capacity in the expanded solar operating window, reducing the need for regulating and backup reserves, EPRI notes. The fossil plant provides stable power output to the grid while balancing the variability of the solar-thermal input as needed. On the downside, however, the CC's steam turbine may operate at part load when solar steam is not available, reducing efficiency.

The development of improved energy-storage technologies is starting to help solar power overcome the handicap of intermittent availability, though. Molten nitrate salt is one way to store thermal energy for periods up to 16 hours per day, making solar-thermal energy available round-the-clock.

Solar integration projects

Plant name	Net output, MW (fossil fuel/solar)	Location	Year online
Martin	1050/75	Indiantown, Fla	2010
Palmdale	555/62	Palmdale, Calif	2013
Cameo	77/1	Palisade, Colo	2010*
Agua Prieta	535/31	Mexico	NAv
Ain Beni Mathar	450/20	Morocco	2010*
Kuraymat	95/20	Egypt	2010
Hassi R'Mel	130/25	Algeria	2010
Yazd	406/17	Iran	2010
Liddell	2000/3	Australia	2008*
Kogan Creek	750/23	Australia	2012
Archimede	130/5	Italy	2010*
Wellington	400/100	Australia	NAv

Source: Electric Power Research Institute, Palo Alto, Calif

Notes: Liddell and Kogan Creek use CLFR technology, all others trough; Cameo, Liddell, and Kogan Creek are coal-fired plants, all others combined cycle; coal-fired plants use solar energy for feedwater heating; at combined-cycle plants it is integrated into the Rankine cycle; asterisks in last column identify plants already operating

The National Renewable Energy Laboratory in Golden, Colo, says that the use of thermal energy storage such as molten salt can boost a solar-trough plant's annual capacity factor from 25% without storage to 70% or higher with it. With that capacity factor, the full nameplate capacity of an ISCC plant with solar-thermal energy storage could be counted on for base-load service.

On deck

As noted earlier, one of the world's first ISCC plants entered service in Morocco in May. The 472-MW, dry-cooled Ain Beni Mathar plant consists of two 179.9-MW gas turbines in a combined cycle with 20 MW added by a solar-trough field. The solar field's nearly 2 million ft^2 of parabolic mirrors, composed of 224 solar collector assemblies (four per loop), cover 217 acres of the plant's 395-acre site. The thermal-oil heat-transfer fluid flows to the heat exchanger at 739F.

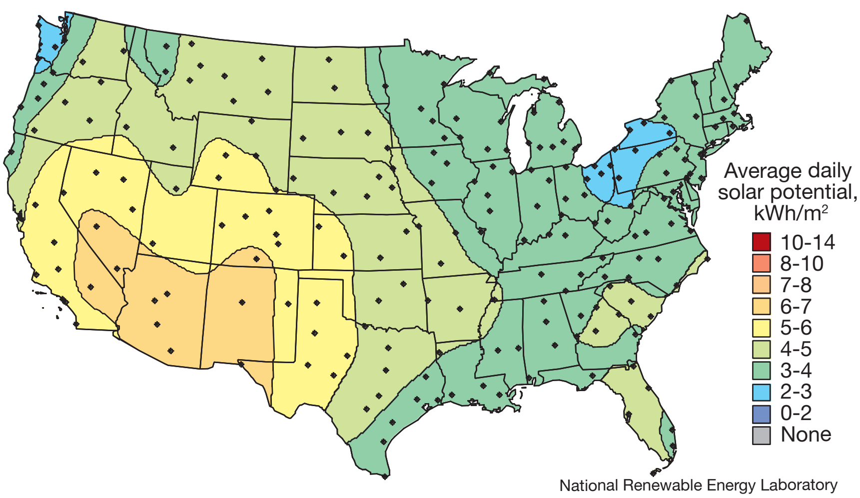
Alstom supplied the two GT13E2 gas turbines, one Comax steam turbine, and three Topair air-cooled generators to the plant under a $230-million contract. The gas turbines generate at 50 Hz with gross electrical efficiency of 36.9%. The exhaust-gas temperature is 950F. Operational details of the plant were not available.

Spanish engineering, procurement, and construction contractor Abener Energia began construction of the $530-million plant in March 2008. The World Bank awarded the project a $43-million credit for solar development.

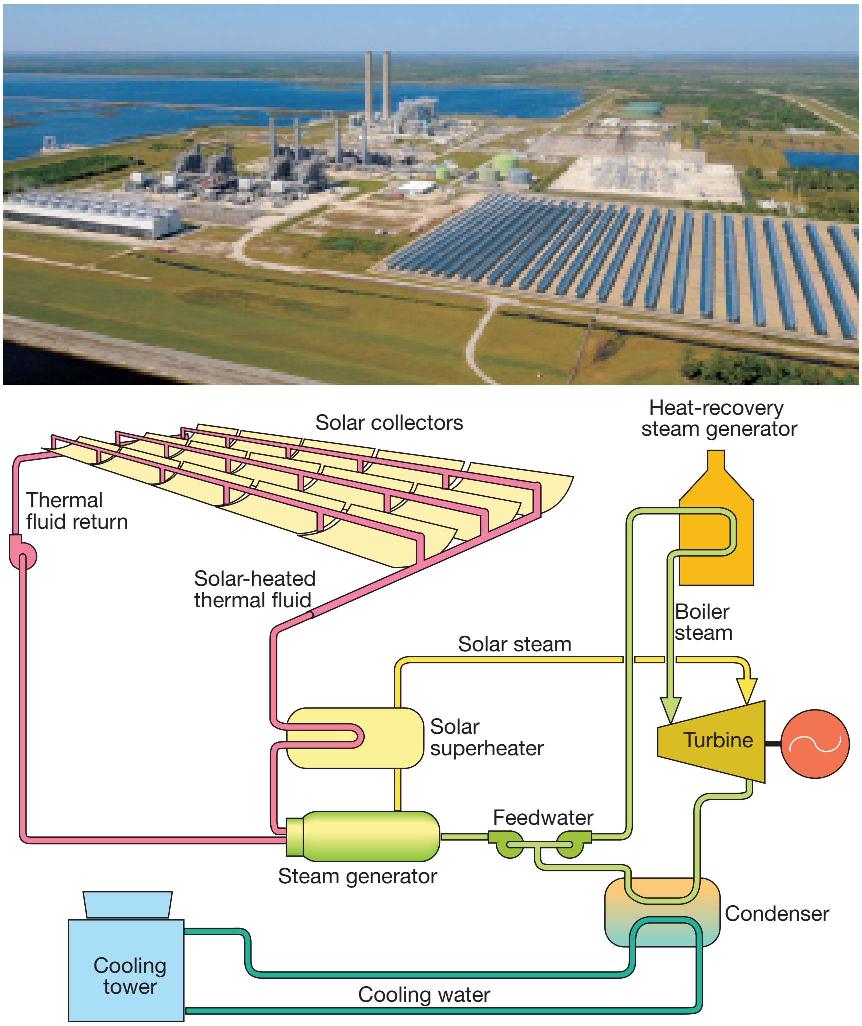
Ain Beni Mathar crossed the finish line first, but several other ISCC plants are close behind. The next to finish could be Hassi R'Mel, the 150-MW project of New Energy Algeria, the state-owned developer of renewable-energy projects. It was scheduled for service in August 2010, but completion has not yet been announced. The plant will have two 40-MW gas turbines, one 80-MW steam turbine and two parabolic-trough solar fields generating 25 MW with nearly 2 million ft^2 of solar collectors in 224 assemblies with four per loop, like Ain Beni Mathar.

Hassi R'Mel shares several other similarities with its Moroccan counterpart: thermal oil heat-transfer fluid, 739F solar-field outlet temperature, dry cooling and UTE Abener, the EPC contractor. But the gas turbines' exhaust temperature of 1112F is much higher, allowing the HRSG to deliver 1004F steam at 1470 psig to the steam turbine. Construction on the $470-million project began in July 2007.

Also in line for completion this year is ISCC Al Kuraymat, a 126-MW water-cooled plant in Egypt. The combined-cycle island contains one GE MS6111FA gas turbine/generator rated at 74.4 MW exhausting to the HRSG at 1112F and a Siemens SST 900 series single-casing



2. The desert region of the Southwest has world-class solar resources



3. A 75-MW solar field being integrated with conventional resources at Florida Power & Light Co's Martin County Plant is expected to begin operating by year-end

condensing steam turbine/generator rated 59.5 MW.

The NEM HRSG includes two low-pressure economizers, an LP evaporator, LP steam drum, and LP superheater to supply the steam turbine's LP section; three high-pressure economizers, HP evaporator, HP steam drum, and two HP superheaters to supply the HP section of the steam turbine.

The solar island consists of 160 parabolic-trough collectors with 1.4 million ft^2 of total aperture. The collectors are arranged in 40 loops, and the Therminol VP-1 heat-transfer fluid enters the solar heat exchanger at 739F.

The steam turbine receives 1004F steam at 1479 psig from the HRSG. When the solar field is active, the steam turbine generates power at its full rating of 59 MW, but that falls to 36 MW when there is no sun. Hence, total plant output is 126 MW with solar radiation, 104 MW without it.

Iran is claiming honors for completing the world's first ISCC plant. Information is sketchy, but news reports say the Yazd Solar Energy Power Plant was synchronized to the grid in stages in 2009, with the solar field being the final stage at the end of the year.

The Yazd project began as a simple-cycle gas turbine plant with three 64-MW turbines dismantled and moved from two other plants. Details and statistics on the ISCC plant changed over the decade during which it was first studied, then proposed, developed, designed, and constructed. It stands now as a 478-MW plant operating in combined cycle, with two 159-MW gas turbines, one 143-MW steam turbine, and a 17-MW solar thermal unit, according to a late-2009 Iranian news report. An earlier description on the Iranian Ministry of Energy's website gives the steam turbine's capacity as 132 MW, but otherwise agrees with the news report.

The plant stands on a 2224-acre site near the central Iranian city of Yazd, a desert location with high solar radiation. The solar field consists of nearly 4 million ft^2 of parabolic-trough collectors in 84 loops (eight collectors per loop), heating Therminol to 736F for generating steam.

Bringing it home

Dependent as it is on solar energy, ISCC can't be used to best advantage everywhere. "Certainly the desert Southwest locations [US], areas that have high direct normal irradiance, or DNI, will have an economic advantage. You'll have much higher capacity factors in those locations," said EPRI's Libby (Fig 2).

"In the Southeastern locations that we've reviewed, the capacity factors were significantly lower. There are still advantages to the technology compared to other solar alternatives. It would be a firm resource because it has the fossil plant to back it up." But a plant owner must do a careful analysis before investing its financial resources.

FPL is preparing to open the first commercial-scale ISCC in the US by December. It is constructing a 75-MW CSP plant to operate in conjunction with the existing gas-fired Martin County Plant in Indiantown, Fla. The $476.3-million facility will have the distinction of being the world's first plant to retrofit a solar-thermal field on an existing combined-cycle powerplant.

The solar array will have 200,000 parabolic mirrors occupying about 500 acres of the plant's 11,300-acre site (Fig 3). They will heat the heat-transfer fluid to 742F before it is pumped to the heat exchangers. When a hurricane threatens, the mirrors will be flipped upside-down for protection. The solar system will be integrated with an 1100-MW, supplementary-fired 4 × 1 combined cycle built in 2003.

In May, Eric Silagy, FPL VP and chief development officer, told an investor conference that the Martin ISCC was under budget and ahead of schedule for a December 2010 start.

Marriage issues

The gas-turbine-powered combined cycle is a proven generation technology; so is concentrated solar thermal. Technical challenges arise when you marry them.

Controlling the flow of solar thermal energy to the combined cycle is the biggest challenge of ISCC, because of the resource's intermittent nature, said Justin Zachary, assistant manager of technology, Bechtel Power Corp, Frederick, Md.

Concentrated solar: a primer

Concentrated solar power (CSP) is the only solar energy technology currently generating power on a commercial or utility scale. Nine solar generating stations totaling 350 MW have been operating for two decades in southern California; a solar-thermal plant, Nevada Solar One, began operation in 2007; and plans have been announced, complete with power-sales agreements, for new solar-thermal plants in California totaling 500 MW.

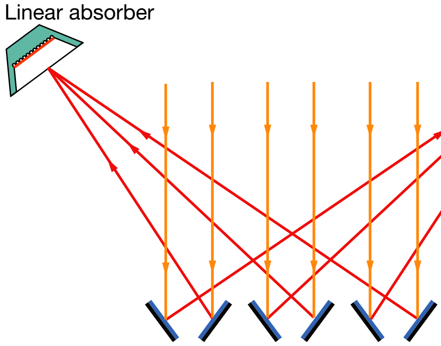
CSP plants can use a half-dozen different technologies, but the three best suited for use in integrated solar/combined-cycle powerplants are the parabolic trough, compact linear Fresnel collector, and the power tower.

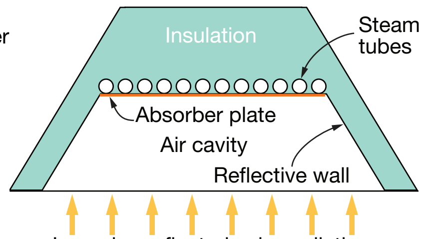
The parabolic trough (Fig A) is an array, on a north-south axis, of parabolic mirrors oriented by computers to track the sun along a single axis. A receiver tube containing a heat-transfer fluid, typically a synthetic oil—such as Therminol®—or molten salt, runs the length of the trough at the focus of the parabola. The fluid is heated up to 745F to serve as a heat source for steam generation. This is the most popular technology today and the one used in all the ISCC plants entering service this year.

NREL

A. Parabolic trough is the most popular solar-thermal technology today and the one selected for all the ISCC plants entering service this year

Compact linear Fresnel. To the untrained eye, the compact linear Fresnel reflector (CLFR) appears similar to the parabolic trough system, with mirrors in long arrays focused on collectors above (Fig B). But its flat mirrors make use of the Fresnel lens effect, which allows for a concentrating mirror with a large aperture and a short focal length. The working fluid is contained in absorbers located at the focal point of the mirrors, which are mounted at different angles to allow several mirrors to focus on one absorber.





B. Compact linear Fresnel resembles the parabolic-trough system, but it produces steam without a heat-transfer fluid and separate heat exchanger. Concept is illustrated at left, details of the linear absorber are at right

A major difference from the parabolic-trough plant is that the steam is created directly in the absorber, not in separate heat exchangers. CLFR has struggled with a reputation for being a low-temperature technology. But a demonstration plant operated by Areva Solar has achieved 716F steam with this technology, and the company is shooting for 752F this summer. "There's nothing that says we can't rival the [solar] towers for steam temperature, but we have to make sure the economics of that make sense," said Milton Venetos, Areva Solar's VP for systems performance.

NREL

C. Solar power tower delivers steam at the highest temperature, but requires scale-up and more experience before being considered a viable candidate for integration with a combined cycle

The solar power tower can achieve the highest maximum steam temperature of the three technologies, 1050F (Fig C). Also called a central receiver, it takes a different approach: A field of thousands of flat mirrors, or heliostats, reflects all solar thermal energy to a central tower, where the heat-transfer fluid, typically liquid sodium or molten salt, is heated. Computers keep the mirrors perpendicular to the bisector of the angle between the directions of the sun and the tower, thus focusing the maximum solar thermal energy on the target.

What's hot, what's not. Feasibility studies for solar/combined-cycle plants conducted by EPRI have been based on parabolic-trough designs. "The basis for that was the much higher maturity of the parabolic trough compared to the other two technologies," said Project Manager Cara Libby. "The linear Fresnel and the central receiver only have been demonstrated at relatively smaller scales than what we were looking at." Central-receiver demonstration plants have been operating for 25 years, she noted, but the largest operating today is a 20-MW plant in Spain. "It's a lower temperature than what you would use for these types of fossil plant integrations. They don't have the high-temperature tower data yet."

Even the parabolic trough can be built only so large to augment a combined cycle, she added. "There is a limit, and usually that's based on things like turbine outlet, moisture content, flow rates through the steam turbine, throttle pressure, and other limitations. Because you're integrating a lower-temperature steam source into a high-temperature part of the steam cycle, there's only so much you can add before you start reaching equipment limitations."

"CLFR is ideally suited for solar/fossil-fired hybrid and other power and industrial process steam applications" because it directly generates high-temperature steam without petroleum-based heat-transfer fluids, thus reducing costs and environmental risks, wrote Areva Solar spokeswoman Katherine Potter in an e-mail. It's also "the most land-efficient solar technology in operation," with energy density as much as two times higher per acre than trough, she said.

"Without the intervention of thermal storage to dampen this, you've got a variable heat input to your combined cycle. This really is not something that a combined cycle would like to have, and you have to adjust the heat input to the combined cycle in order to match that of the solar field."

In an ideal world, you would want to build ISCC plants already optimized from the ground up, but most such plants in the US for now will be built as retrofits on combined cycles, "because people want to understand how those two different beasts behave together," Zachary said.

Zachary described approaches to integrating solar steam in a combined cycle in a December 2009 white paper written in collaboration with David Ugolini, senior principal engineer, and Joon Park, financial analyst, both also with Bechtel. The paper points to steam conditions of the solar steam as the key to successful integration that "maximizes the use of both energy sources."

The authors note that evolving solar technologies now produce steam they categorize as high temperature (>930F), medium temperature (750F) and low temperature (480F-570F). Their discussion focuses mainly on medium-temperature technology because it is "the most proven."

The paper identifies parabolic-trough as the "most common medium-temperature solar technology." It calls CLFR a low-temperature technology, but Areva Solar officials say that classification overlooks the achievement at their 5-MW Kimberlina demonstration plant, where they have produced 716F steam.

"Studies indicate that, for parabolic-trough systems generating steam up to around 745F, it is best to generate saturated high-pressure steam to mix with saturated steam generated in the HRSG HP drum," say Zachary and his colleagues (refer back to Fig 1).

"Integrating HP saturated steam into the HRSG and sending heated feedwater from the HRSG is common in integrated gasification/combined-cycle (IGCC) plants," says the white paper. A twist unique to ISCC is the need to take feedwater supply to the solar boiler from the proper location in the steam cycle so as to maximize feedwater heating in the HRSG and minimize it in the solar field. The authors advise taking feedwater that has been heated in the HRSG HP economizers because doing so maximizes the GT exhaust energy used to heat the feedwater and minimizes the size of the solar field needed to produce a given amount of steam. CCJ

A cornucopia of ideas for improv

Personnel at gas-turbine-based powerplants face challenges daily that some others in the electric-generation sector might not experience even once in an entire career. The typical 2 × 1 F-class combined cycle produces a nominal 500 MW with two-dozen or fewer employees—barely enough to respond to the dispatch demands of grid operators who rely on GTs to assure system reliability.

Keeping three generating units operating in synch requires the full attention of all hands, leaving precious little time to think about improvements that might boost efficiency, starting reliability, availability; reduce emissions; and make the plant a safer workplace.

1. Tenaska Virginia personnel display 2010 Best Practices Awards—including the Best of the Best for Safety—earned by the plant only a few days before the facility flew the Star Worksite flag for the first time. Front row (l to r): Jay Hoffman, Mike Bolton, Donnie Scott, Terry Whitlock, William Bridgwater, Brian O'Neill, Vincent Satterly, Gary Brown, Clay Haden, Edward Puskaric, and Forrest Benjamin. Back row: Dennis Hansen, Karl Partner, Roy Massey, Rich Collins, Pat LeFloch, Nick Miles, Andy Wilson, James McCollough, James Bell, Aubry Tharp, and Wayne Scott

That's why user-group meetings are so valuable. They get you out of the plant and into an environment conducive to collective thinking and problem-solving. No one individual has *all* the answers. The Best Practices Awards program complements the face-to-face discussions among users and the online bulletin boards offered by most groups for idea-sharing 24/7.

The awards program was launched six years ago by the COMBINED CYCLE Journal, in association with the Combustion Turbine Operations Task Force (CTOTF), the nation's oldest user group serving owner/operators of gas-turbine-based generating facilities.

The goal: Recognize the valuable contributions made by plant and headquarters staffs in improving the safety and performance of simple-cycle, cogeneration, and combined-cycle facilities (Sidebar 1). And in so doing, build a library of virtually timeless *proven* ideas for others to consider for implementation at their plants (Sidebar 2).

There are two levels of awards to recognize achievements at individual plants: Best Practices and the Best of the Best, as determined by the scores of judges selected from the CTOTF Leadership Committee. Entries are evaluated based on real and measurable achieved business value, complexity of the issue, operations staff involvement, degree of coordination across plant and headquarters engineering and O&M groups, and duration of impact.

Seven judges reviewed entries from nearly four-dozen finalists this year—a record. Also noteworthy: More than half of the plants submitting entries this year had never participated in the program previously.

The judges included management personnel responsible for fleet-wide O&M planning and execution, plant managers, and aero and frame experts totaling well over a century of powerplant experience.

The traditional five award categories—O&M, management, safety,

1. 2011 Best Practices Awards

Enter today while the accomplishments of plant personnel are fresh in your mind

One way to get management's attention long enough to appreciate the contributions you and your co-workers are making on a daily basis is to win an industry award. The Best Practices Awards program conducted by the COMBINED CYCLE Journal, and endorsed by the Combustion Turbine Operations Task Force (CTOTF), recognizes ideas implemented by plant personnel to increase reliability/availability, improve efficiency, reduce emissions, minimize accidents, etc. Such performance improvements are important to every owner and its management team.

To enter the 2011 Best Practices Awards competition, access the requirements/rules page at www.psimedia.info/bestpractices.htm.

The program supports work done in gas-turbine-powered combined-cycle, cogeneration, and peaking plants larger than 5 MW. There are seven awards categories: Management, Environmental Stewardship, Safety, Design, O&M Business, O&M Major Equipment, and O&M Balance of Plant.

Your entry should take no more than about two hours to prepare and e-mail to scott@psimedia.info. Photos and diagrams explaining the work done, plus a picture of your plant, are welcomed. The deadline is Dec 31, 2010, but don't wait: Prepare the entry today, while the accomplishments are fresh in your mind.

Judging will be by a panel of experts from the CTOTF Leadership Committee.

ing plant performance, safety

design, and environmental stewardship—were expanded this year to seven by splitting O&M, which represents about half the entries, into three subcategories: Business, Major Equipment, and Balance of Plant.

Proof that no individual, plant, or company has a "lock" on the best ideas was clearly in evidence when the Best of the Best recipients were announced. No plant won more than one of the nine top awards (there were ties in two of the seven categories: O&M Balance of Plant and O&M Business). And only one of the group, Tenaska Virginia Generating Station, had been awarded a Best of the Best previously. That was in 2006 for Management.

Dr Robert Mayfield's Tenaska Virginia 3 × 1 combined cycle was one of the big winners this year, taking home the Best of the Best for Safety as well as Best Practices Awards in the O&M Major Equipment and Management categories.

That Mayfield's team (Fig 1) has done an exceptional job in the area of safe work practices was in evidence the week after awards presentation when Virginia Dept of Labor and Industry Commissioner Courtney Malveaux announced publicly that the plant had been approved as a Star Worksite under Virginia's Occupational Safety and Health Voluntary Protection Program (VPP)—the highest level of recognition. A fitting certificate was issued by Virginia Governor Robert F McDonnell and the Star Worksite flag was presented to plant employees by Malveaux during a visit to the Scottsville facility.

In addition, Maintenance Manager Sam Graham, the 2010/2011 Chairman of the 7F Users Group, received a letter from US Senator Mark Warner (D-Va), which read in part:

"This certification is a testament to the pride you take in your community and in the Commonwealth of Virginia. The VPP concept recognizes that enforcement alone can never fully achieve the objectives of the Occupational Safety and Health Act (OSHA). Good safety management programs that go beyond OSHA standards can protect workers more effectively than simple compliance."

Three other plants matched Tenaska Virginia's "take" with three awards each:

- Jack County Generating Facility, Brazos Electric Power Cooperative Inc, received one of two Best of the Bests in the O&M Balance of Plant category, plus two Best Practices plaques. Operations Supervisor Troy Cannon and Lead Water Plant Operator Ronnie Johnson accepted the awards (Fig 2).
- Klamath Cogeneration Plant, Iberdrola Renewables Inc, a perennial winner in the Best Practices competition, received Best Practices Awards for Design, Management, and Safety. Operations and Engineering Manager Bruce Willard accepted the hardware (Fig 3) while Plant Manager Ray Martens, a member of the 501F Users Group steering committee, remained at the plant to keep a GT major (with upgrades) on track.
- Jasper Generating Station, South Carolina Electric & Gas Co, received Best Practices Awards for O&M Balance of Plant, Design, and Safety. Plant Manager Steve Palmer accepted the plaques (Fig 4).

Tenaska Inc and its subsidiaries collectively garnered the most awards on a fleet basis. The successes of Covert and Tenaska Central Alabama Generating Stations, when added to the three awards presented to Tenaska Virginia, totaled two Best of the Best and four Best Practices Awards. Rich Evans, who accepted the Covert plant manager's position only a few weeks prior to the deadline for submitting award entries, came away with the Best of the Best for Design (Fig 5).

2. Jack County Generating Facility: Troy Cannon (left) and Ronnie Johnson

3. Klamath Cogen's Bruce Willard (right) needed Senior Editor Scott Schwieger to help him display the plant's three awards

4. Plant Manager Steve Palmer holds one of three awards presented to Jasper Generating Station

5. Covert Generating Plant: Maintenance Mechanic Pete Mays, Plant Manager Rich Evans, and Maintenance Manager Bucky Ray (l to r)

6. Tenaska Central Alabama Generating Station: Operations Manager Cecil Boatwright, Plant Manager Robert Threlkeld, and Plant Engineer Brian Pillittere (l to r)

7. NV Energy: Nitin Luhar, Rhoda Bowman, Andy McNeil, and Kevin Newcomb (l to r)

8. Central de Ciclo Combinado Saltillo: Maintenance Manager Roberto Hernandez, Plant Manager Rene Villafuerte, and Operations Manager Juan Diaz (l to r)

Robert Threlkeld, who manages Tenaska's Central Alabama and Lindsay Hill Generating Stations, collected his facilities' 16th award (Fig 6). The two plants, which have received at least one award between them every year since the program's inception, failed to capture a Best of the Best for the second year running after receiving five in the first four years.

Second to Tenaska in terms of fleetwide success was NV Energy, which captured one of the two Best of the Bests for O&M Business as well as three Best Practices Awards. The successful entries came from the Walter M Higgins and Harry Allen Generating Stations (Fig 7).

Among the independent O&M companies serving at GT-based powerplants, NAES Corp had the greatest success by far. Seven facilities under contract to the Issaquah (Wash)-based company received a total of nine awards, including one Best of the Best. The plants recognized: Covert, New Harquahala, TermoEmcali, Blackhawk, Mustang, Wolf Hollow I, and Granite Ridge.

International participants. The Best Practices Awards program officially recognized participants from outside North America in 2010. That decision was made in conjunction with one to begin mailing copies of the COMBINED CYCLE Journal to key personnel at all GT-based plants

2. How to access CTOTF's Presentations Library

Information that can (1) help solve a nagging O&M problem, (2) improve availability, efficiency, safety, (3) reduce emissions, (4) assist in outage planning, etc, is readily accessible via the CTOTF's Presentations Library, which is part of the organization's Internet Bulletin Board Communications Service (IBBCS).

The library currently contains more than 260 presentations from meetings conducted from 2006 through spring 2010. While it's true that CTOTF IBBCS might be the acronym to end all acronyms in this over-acronymed industry, it's one you should commit to memory because it can "save your bacon."

Further, given budget cuts, staff-size challenges, and generally unsympathetic management it's difficult to get to all (any) of the meetings you want to attend. But *user* access to prepared remarks from CTOTF conferences is only a few mouse clicks away—after you register (it's *free*). *User* is defined as a person employed by a company that owns and/or operates gas turbines, or has its first units under construction.

Here's how to get your "library card" and access to CTOTF's valuable bulletin-board service:
Access www.ctotf.org.

- Click on the "New Member" button on the horizontal toolbar at the top of the page.
- Complete and submit the online membership registration form.
- Confirmation of your acceptance as a CTOTF member with full IBBCS privileges generally will be e-mailed to you within 72 hours.
- As a member, go to www.ctotf.org, and click the flashing link "Free Online Bulletin Board Service." Next, scroll down the page to "Presentation Library" and click on that link. Presentations are arranged in chronological order, by meeting, most recent first. So it's easy to find any presentation referenced in the COMBINED CYCLE Journal.

When you click on a presentation, the first information that pops up is the complete title of that presentation, the name of the presenter, and an abstract. The PowerPoint slides are accessed by clicking the word "here" under the abstract—as directed. After you have reviewed a presentation, you may want additional information. Return to the abstract page and access the presenter's website by clicking the link after his or her name.

Finally, if there's a particular subject you want to know more about—say, borescope inspections—click on the search button at the top of the page and complete the pop-up form. A Google-like search engine will line up for your review all the material CTOTF has to offer. With these resources at your fingertips, there's no reason not to keep up with what's going on in the gas-turbine-based sector of the electric power industry.

9. **Araucaria Power Station:** Director of Generation Raul Munhoz, Operations Manager Fernando de Albuquerque, and Plant Manager Amilton Bizi (l to r), all representing COPEL, the plant operator; and Flavio Chiesa, technical director for UEG Araucaria Ltda, the plant owner

in the Western Hemisphere with this issue. Previously, the magazine was delivered only to generating facilities in the US, Canada, and Mexico.

Best Practices Awards were presented to three plants outside the US: one each in Mexico, Colombia, and Brazil. Central de Ciclo Combinado Saltillo, one of two Mexican facilities recognized in 2009, was successful again this year, in the O&M Balance of Plants category (Fig 8). Colombia's TermoEmcali, a municipally owned plant operated by NAES, and Brazil's Araucaria Power Station (Fig 9), each received Best Practices Awards for their O&M Business entries.

Sponsors. Finally, a tip of the hat to the sponsors, without whom an awards program of this magnitude would not be possible: Advanced Turbine Support Inc, Dresser-Rand Leading Edge Turbine Technology Services, Gas Turbine Efficiency, Goose Creek Systems Inc, Hy-Pro Filtration, Jansen's Aircraft Systems Controls Inc, KE-Burgmann USA Inc, NAES Corp, PSM-Power Systems Mfg LLC, SmartSignal Corp, Turbine Energy Solutions, Wood Group GTS, Young & Franklin Inc, and Zokman Products Inc.

10. **Ceredo Generating Station:** Plant Manager Pat Myers accepts award from Editor Bob Schwieger

To dig deeper, you only need access to the Internet. Think of the inscriptions for the Best Practices Awards plaques that follow as an index to proven ideas that you can implement to improve plant operations and better protect personnel. When you identify a promising idea, you can get more detail simply by accessing www.combinedcyclejournal.com/archives.html and clicking on 1Q/2010. Links to entries for each of the award categories are listed on the cover and only one mouse click away.

Want still more ideas? Go back to www.combinedcyclejournal.com/archives.html and click on the 1Q issues back to 2005.

Sometimes the information disseminated in the magazine is not sufficient for your needs. Mike Elmo of Goose Creek Systems, the company that organizes the CTOTF's conferences, has created voice-over PowerPoint (VOPP) files for each of the 2010 Best of the Best recipients. The presentations, nominally 10 minutes long, are much better than silent slides, which often leave you guessing as to what the creator was trying to get across.

Access to the VOPP presentations (users only!) is through www.ctotf.org. Just log on to the site and access the Internet Bulletin Board Communications Service (IBBCS). Scroll down to the Presentation Library and locate the PowerPoint you're looking for. Site registration is open to all GT owner/operators; just follow the directions in Sidebar 2 if you don't currently have access.

Best of the Best recipients

O&M Balance of Plant

Ceredo Generating Station

American Electric Power Co

Development of a comprehensive Excel spreadsheet to guide safe and efficient response to protective relay operation is critical to personnel safety, plant availability, and NERC compliance (Fig 10).

Jack County Generating Facility

Brazos Electric Power Cooperative Inc

Development and implementation of an online boil-out procedure for the crystallizer in the plant's zero-liquid discharge facility increased reliability and reduced the forced-outage rate for a critical piece of equipment.

O&M Business

Walter M Higgins Generating Station

NV Energy

Implementation of a grassroots, condition-based maintenance program identifies critical equipment for effective predictive and scheduled maintenance. Development of a work management strategy, re-evaluated

11. Effingham County Power: James Goins (left) and Nick Bohl

12. Desert Basin Generating Station: Jess Bills and Moh Saleh

13. Covert Generating Station: Brant Quinn, Tony Kenwabikise, Kent Retterbush, John Morse, Jay Slakes, Brian Kemp, Louis Proctor, Jessica Gordon, Paul Harden, Pete Mays, Rich Evans, Don Eaddy, Mark Wright, Jeff Calkins, Jason Canning, Willie Oliver, Rich Gordon, Aaron Hutchinson, DeLoyd Hillock, Bucky Ray, Gene Vasquez, Brian DeWitt, Kevin Palmore, and Gary Boreham (l to r). Camera shy: Anita Morris, Michael Stevens, Bill Cole, and Max Poindexter

14. Hopewell Cogeneration Facility: Chuck Barnes

monthly, ensures effective and timely maintenance.

Effingham County Power

Owned by Mackinaw Power Holdings LLC

Operated by CAMS

Modifications to outdated operating procedures and retraining of operators helped to greatly reduce the costly monthly variance and imbalance charges set forth by the plant's tolling agreement (Fig 11).

O&M Major Equipment

Desert Basin Generating Station

Salt River Project

Implementation of a working platform specifically designed for generator rotor removal increases personnel safety, reduces costs, and eliminates the possibility of equipment damage during generator rewind outages (Fig 12).

Design

Covert Generating Facility

Owned by New Covert Generating Company LLC

Operated by NAES Corp

Replacement of 45 unreliable motor-operated valves with a superior design effectively facilitates maintenance while increasing reliability. New valves have experienced zero failures in five years (Fig 13).

Environmental Stewardship

Hopewell Cogeneration Facility

GDF Suez Energy North America

Plant staff developed and implemented new operating procedures to reduce NO_x emissions on unit start-up by minimizing the amount of time the gas turbines run without steam injection. Results: Environmental benefits and a significant saving in NO_x credits (Fig 14).

Management

Bethlehem Energy Center and Linden, Bergen, Guadalupe, and Odessa Generating Stations

PSEG Fossil LLC

A fleetwide initiative to improve operational performance using mobile training facilities increases scheduling flexibility and employee participation without interfering with plant operations (Fig 15).

Safety

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

A comprehensive initiative to increase fall protection involves iden-

15. PSEG Fossil LLC: Mike Dammann (left) and Joe Mosteller tifying fall hazards, brainstorming solutions, and establishing new procedures. Improved personnel safety helped plant gain OSHA VPP Star certification.

Awards for O&M Balance of Plant

New Harquahala Generating Co LLC

Owned by MachGen Holdings LLC

Managed by Competitive Power Ventures

Operated by NAES Corp

Development and improvement of predictive and preventive maintenance practices by implementing a comprehensive, hands-on approach for vibration monitoring of rotating equipment pays significant dividends by safeguarding critical equipment.

16. Blackhawk Station: Craig Courter (right)

Central de Ciclo Combinado Saltillo

Mitsui & Co Ltd and Tokyo Gas Co Ltd

Increased thermal load on the plant's cooling systems from extreme summer temperatures decreased power output. By reducing the incidence of sunlight on radiators, finned tubes, and piping, the plant maintained maximum load last summer.

Jack County Generating Facility

Brazos Electric Power Cooperative Inc

Multiple design modifications to streamline operation of the belt-filter press in the plant's zero-liquid-discharge facility increased availability of this critical piece of equipment by 36% while reducing manpower requirements.

Jack County Generating Facility

Brazos Electric Power Cooperative Inc

Unexpected microbial degradation of HERO™ membranes prompted design modifications that improved both water chemistry and operation of the ZLD system.

Jasper Generating Station

South Carolina Electric & Gas Co

Compressed-air piping was reconfigured to prevent dryer desiccant fouling by oil carried over from the compressor. Capability to monitor dryer delta p also was added to identify potential operating issues early.

Pinelawn Power LLC

Owned by J-Power USA Development Company Ltd

Operated by Wood Group Power Operations Inc

Upgrading of the condensate polisher allows the plant to reclaim backwash water as cooling-tower makeup after settling and filtration, thereby significantly reducing the cost of off-site waste disposal.

Awards for O&M Business

TermoEmcali

Owned by Empresas Municipales de Cali

Operated by NAES Corp

Personnel developed and implemented a comprehensive program to elevate plant performance while operating on fuel oil. Result: The modifications and improvements were paramount to the plant's success in becoming the first gas-turbine-based power station in Colombia to achieve regulatory compliance for operating solely on fuel oil.

Blackhawk Station

Owned by Borger Energy Associates LP

Operated by NAES Corp

Development and implementation of an Infrequent Operating Procedure program for approving and conducting unscheduled maintenance has dramatically improved the reliability of steam supply to the plant's thermal host (Fig 16).

17. Mustang Station: Matt Cochran accepting for NAES on behalf of the plant

Mustang Station

Owned by Denver City Associates LP, GS Electric Generating Cooperative Inc, and Yoakum Electric Generating Cooperative Inc

Operated by NAES Corp

Implementation of the Shift Training Evolution program to review procedures for seasonal operating occurrences provides plant personnel the knowledge, confidence, and tools to safely and effectively perform O&M tasks for infrequent events (Fig 17).

Araucaria Power Station

Owned by UEG Araucaria Ltda

Operated by COPEL SA

With commercial issues delaying the startup for four years and a seasonal operating schedule, plant staff developed and implemented a comprehensive BOP preservation program to minimize equipment degradation. Result: The plant's availability exceeds 98% with no significant problems attributed to degradation.

Desert Basin Generating Station

Salt River Project

Improved availability and reliability, and reduced costs, are benefits gained from a comprehensive program that integrates best-in-class analytic and diagnostic tools. Results include increased awareness of possible issues and greater control over major equipment.

Emery Generating Station

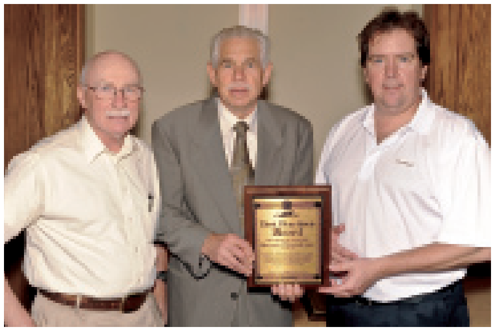
Interstate Power & Light, an Alliant Energy company

Development of a comprehensive spreadsheet using EtaPRO™ and Excel allows plant operators to accurately track the cost and duration of each startup for benchmarking purposes.

18. Palomar Energy Center: Plant Manager Dan Baerman

19. Osprey and Columbia Energy Centers: Roy Price, Osprey's lead I&E technician

20. Granite Ridge Energy: Jim Carlton, Jim Barrett, and Larry Hawk (l to r)



21. Holtsville CT Power Station: Matt Gaskin (left) and Peter Grzybowski (right)

Walter M Higgins Generating Station

NV Energy

Implementing a formal operator qualification program to effectively train and familiarize plant personnel with over 50 plant systems and their standard operating procedures helps maintain top productivity.

Awards for O&M Major Equipment

Palomar Energy Center

San Diego Gas & Electric, a Sempra Energy utility

Installation of a chiller system with eight modes of operation ensures predictable and reliable output regardless of the weather, greatly increases output on hot days, and selection of the optimal operating mode with minimal operator intervention (Fig 18).

Tenaska Central Alabama Generating Station

Tenaska Alabama II Partners LP

Keen awareness of personnel during plant operation led to an adjustment of steam seal pressure to an optimal level to reduce turbine backpressure. Benefit: A decrease in overall plant heat rate of more than 1%.

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

Use of the plant's "Six Steps for Continuous Process Improvements" solutions approach virtually eliminated HMI failures attributed to hard drives and power supplies. Benefits include higher reliability and efficiency and well as increased flexibility.

ManChief Generating Station

Owned by ManChief Power Company LLC and Capital Power Corp

Operated by Colorado Energy Management LLC

Installation of duct balloons in gas-turbine exhaust plenums offers a cost-effective solution for keeping turbine disks above the minimum temperature specified by the OEM without additional heating.

Awards for Design

Harry Allen Generating Station

NV Energy

Implementation of an interdepartmental system to manage construction-project responsibilities focused greater attention on the planning phase and resolved overlaps during the construction phase.

Harry Allen Generating Station

NV Energy

Incorporating "lessons learned" from past construction projects and the creation of a document system to gather information and educate personnel positively impacts new projects by creating a cohesive and efficient team environment.

Jasper Generating Station

South Carolina Electric & Gas Co

In-house design, fabrication, and installation of permanent sample lines upstream of the SCR enables a streamlined method for tuning of the gas-turbine CEMS and eliminates previously unavoidable rental and labor costs.

Klamath Cogeneration Plant

Iberdrola Renewables Inc

Modification of the gas-turbine drain line to a more practical and efficient design eliminates inlet suction during offline water washes. It also allows visual verification of positive drainage during operation as well as drain cleanout when necessary.

Awards for Environmental Stewardship

Osprey and Columbia Energy Centers

Calpine Corp

Utilizing the plants' distributed control systems to continuously track and compare chemical tank levels, an alarm system was developed to alert plant personnel of possible chemical leaks. The alarms have effectively reduced accident response and cleanup time (Fig 19).

Granite Ridge Energy

Owned by Granite Ridge Energy LLC

Operated by NAES Corp

A chemical evaluation of the plant's cooling water led to the introduction of an environmentally friendly treatment using bromine. Results: An 80% reduction in chlorine consumption and a 60% reduction in the permit level (Fig 20).

Holtsville CT Power Station

National Grid

Faced with a changing operating profile and a stricter regulatory framework, the plant installed a system to inject high-pressure water into the fuel oil prior to combustion. Results: A reduction in NO_x emissions by more than 50% and environmental compliance without the need for NO_x credits (Fig 21).

Mint Farm Generating Station

Puget Sound Energy

Plant staff, in partnership with the local regulatory agency, used CEMS (Continuous Emissions Monitoring System) testing to minimize NO_x and NH_3-slip emissions. Result: A total reduction in combined emissions of 47% based on the plant's intended operating limit (Fig 22).

22. Mint Farm Generating Station: Dave Hooper (left) and Robert Mash

23. Wolf Hollow I LP: Kelly Fleetwood, Adam Jackson, and Jeff Grundman (l to r)

25. MEAG Wansley Unit 9: Bert Wright, I&C technician

Awards for Management

Granite Ridge Energy

Owned by Granite Ridge Energy LLC

Operated by NAES Corp

Development and implementation of a critical equipment management plan ensures appropriate and effective response in the event a major plant component fails. Two high-risk areas addressed are generator step-up transformers and the cooling-water pipeline.

Klamath Cogeneration Plant

Iberdrola Renewables Inc

Implementation of a comprehensive document control policy for P&IDs and electrical drawings ensures that the most up-to-date information is used by plant personnel and third-party contractors.

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

Ensuring that contractor personnel understand the plant's safety policies and partner in its safety culture is critical to maintaining a safe workplace. Contractors are encouraged to raise safety concerns/issues and to participate in their resolution.

Wolf Hollow I LP

Owned by Stark Investments

Operated by NAES Corp

Development and implementation of a model that predicts and schedules the plant's capacity on an hour-to-hour basis effectively minimizes exposure to market risks and offers opportunities to capitalize on favorable market conditions (Fig 23).

24. AE Units 3, 4, 5: Ed Stewart (left) and Carl Massart came up with and implemented the idea that earned Allegheny Energy its first Best Practices Award

Awards for Safety

AE Units 3, 4, 5

Allegheny Energy

Replacing ladders and man-lifts to access circulating-water pumps for motor-bearing lubrication with new drain lines and a mobile filter cart for ground-level access successfully eliminates personnel safety hazards (Fig 24).

Covert Generating Facility

Owned by New Covert Generating Company LLC

Operated by NAES Corp

Frequent need to access the evaporative-cooler filter house for maintenance using an outside basket ladder was viewed an unnecessary hazard. Staff and owners collaborated to design an indoor stairway and platform for safe, efficient inspection and repair.

Jasper Generating Station South

Carolina Electric & Gas Co

Plant purchased and installed safety sheds and hurricane window film to protect personnel against severe weather. The sheds can withstand winds of 250 mph.

Klamath Cogeneration Plant

Iberdrola Renewables Inc

Installation of a pressure regulator and gage, a set of relief valves, and double block and bleed system to control and monitor air pressure and flow to chemical-delivery trucks during offloading operations mitigates the danger of exceeding a tanker's pressure limits.

MEAG Wansley Unit 9

Owned by Municipal Electric Authority of Georgia

Operated by GE Contractual Services

Monthly calibrations of sensors in the ammonia-tank containment area presented a fall hazard and ergonomic issues for technicians. Plant staff designed and fabricated bottle racks for calibration-gas tanks allowing technicians to work hands-free and with a greatly reduced risk of falling (Fig 25).

State Line Combined Cycle

Empire District Electric Co and Westar Generating Inc

Implementation of a computerized lock-out/tag-out system linked to the maintenance management system and master lockbox increases the level of safety for personnel and outside contractors. Results: Zero reportable injuries on equipment covered by the LOTO system since its inception.

Whiting Clean Energy

BP

Elimination of fall exposure and risk when accessing scaffolds was achieved through the installation of retractable, "yo-yo adapter" lanyards on all scaffold access ladders

Memphis beckons

Pack your bags. The 2010 7EA Users Group meeting opens October 26 at The Peabody in Memphis with a pre-conference workshop. Interactive group discussions and prepared presentations start the following day; vendor fair is Wednesday evening (details at http://ge7ea.users-groups.com).

There's no better place for 7B-EA owner/operators to network and learn new ways to improve productivity and performance. Challenging days ahead for personnel responsible for this group of engines: The need to integrate intermittent renewables (solar and wind) into the generation mix in states with Renewable Portfolio Standards will likely demand more frequent and faster starts and a new operational paradigm (think ancillary services) to maintain a healthy balance sheet.

You can prepare for the coming market changes and keep up on lessons learned with a total investment of about $1500 (air fare, hotel, registration fee), which is a dollars-and-sense O&M investment you can't beat these days.

By not participating, your plant's O&M costs almost surely will *increase* unnecessarily. Deck-plates personnel tell the editors that user-group meetings always provide two or three good operating and/or maintenance ideas that when implemented cut expenses, in sum, by five figures within a year. And who can put a price tag on the safety idea that reduces worker exposure to harm?

The Miami experience

The summary of last year's meeting in Miami that follows speaks to the value proposition of participation. Attendance was down by about 20% in 2009 (versus 2008) because of budget cuts industry-wide as electricity sales dipped for the second consecutive year for only the second time in the nation's history.

Economic hobgoblins forced financial executives into making broad-brush cuts, which was unfortunate. The pre-conference workshop on maintenance planning, conducted by PAL Turbine Services LLC, Clifton Park, NY, alone offered ideas on how to *reduce* annual expenses at many plants by tens—possibly even hundreds—of thousands of dollars.

The best practices identified in the workshop were especially significant for the 7B-EA fleet. With gas prices down and estimates of reserves ranging up to 100 years, these reliable workhorses typically are seeing more starts and hours than they have in the recent past. Not attending was akin to shooting yourself in the foot.

There certainly is plenty of information to share for this fleet. A year ago, by the OEM's count, the 776 7EAs installed had accumulated 129,000 starts and more than 12-million fired hours. The global installed base for 7A-EA engines was 1141 (two As, 224 Bs, 9 Cs, and 130Es, in addition to the EAs) and they had operated 34-million fired hours. More than two-thirds of those hours were registered by machines with DLN (dry low NO_x) combustion systems.

Steering committee drives program content

Patrick Myers, plant manager, Ceredo Generating Station, American Electric Power Co.

Ray Lathrop, maintenance supervisor, Earl F Wilson Power Plant, Corn Belt Power Co-op (Iowa).

Jim Beveridge, plant manager, Nebo Power Station, UAMPS-Utah Associated Municipal Power Systems.

Amy Alix, engineer, Progress Energy.

Thomas Miller, plant manager, Combustion Turbine Dept, Kansas City Power & Light Co.

Lane Watson, account engineer, FM Global.

How to cut outage costs

"Maintenance planning and what to do when the budget is reduced" was both the title and mission statement for the workshop conducted by PAL's vibrant Senior Engineer Charlie Pond, who was assisted briefly by GM Dave Lucier from the company's main office in a demonstration of online problem solving (more on this later).

First step, Pond said, was to decide on job scope and start date. Would your effort be a full-blown combustion (CI), hot-gas-path (HGP), or major inspection; a generator inspection; or simply system maintenance? Remember, he continued, early definition of work scope translates to savings because you have more time to shop for good deals on parts and labor.

A detailed borescope inspection can provide information critical to developing a realistic outage plan. Pond double-stressed its importance. He said a knowledgeable borescope inspection team identifies in advance specific problems that must be addressed and corrected, thereby providing invaluable guidance for budgeting and scheduling. Depending on inspection results, you may decide to perform the outage sooner, or perhaps postpone it.

Be flexible on start date if possible, Pond advised. In the middle of the "outage season" tools and labor cost more—it's a supply and demand thing. Also, service shops have longer lead times and have limited ability to adjust shop work flow without financial penalty if your schedule changes.

After deciding on job scope, make your spare-parts list. Be thorough. Pond flashed a typical parts list on the screen. It included the names of the individual parts, drawing numbers, quantity required for a given type of inspection, etc. Mind-numbing. A lesson on the GE parts numbering system followed to assure attendees would get what they thought they were ordering.

Don't forget the "expendables," the thought leader said. Rags, duct tape, plywood, tarps, rope, etc: Make sure you'll have sufficient supply on hand. Next, compare the lists of spares and expendables to inventory and begin ordering "as early as possible," he urged, "to save money."

"How do you know what spares to have on hand? Where do you draw the line?" Pond answered the rhetorical questions this way: "It all depends on your situation." Examples: A refinery running 24/7 should have a full set of spares; a peaking plant operating a nominal 100 hr/yr, minimum spares; a peaking plant running 1000 hr/hr, balance spares versus profit or value; a combined-cycle or cogen plant making lots of money, don't jeopardize the revenue stream by shorting spares.

Next topic: Options for conducting the outage and their advantages/disadvantages. They include:

- Long-term service agreement (LTSA). Typically the most expensive; outages are planned; no parts tracking.
- Turnkey. Second most expensive. Cautions: Beware (1) a "low-ball" bid, (2) short cuts to save the contractor money at your expense, and (3) add-on work.
- Hire technical advisor and labor separately. TA ensures that the customer gets a quality job; monitors and documents extra work and delays.
- In-house overhaul process. PAL's IHOP can translate into hundreds of thousands of dollars in savings. For details, access www.combinedcyclejournal.com/archives.html, click 2Q/2009, click 7EA on issue cover and scroll to p 32, "Plant personnel do HGP."

Regarding participation by technical advisors, PAL recognizes that these experts don't necessarily have to be onsite to participate in all decision-making—particularly during the outage-planning stage. Travel is expensive—and getting more so every day—and saps the industry's limited personnel resources.

The company has equipped its website with a feature—so-called TOPS for Turbine Online Problem Solving—that allows customers to confer with PAL experts at headquarters, in regional offices, and in the field. The system allows uploading of electronic documents to the chat room where the private discussions take place with video and audio support. If a customer's conference room can support audio and video as well, more can participate in the discussions.

Pond demonstrated the effectiveness of this communications medium by dialing up Dave Lucier at the company's main office in upstate New York. Lucier then demonstrated how he and a PAL field engineer working in Florida had solved a control system problem for a power producer in Alaska via the Internet. Thousands of dollars were saved in charges for non-productive TA time and travel.

There are many ways to plan the job, Pond said, identifying several packaged software programs available commercially. Selecting the right tool for your purposes requires thorough due diligence.

He prefers the Critical Path Method (CPM), but only if you are going to analyze the result and brainstorm with key personnel ways to shorten job duration.

This might mean adding manpower at the beginning and end of the project where there are many tasks that can be done in parallel; ordering of labor-saving specialized tooling; performing tasks in advance of the outage (organization of drawings and forms, construction of shipping crates, identification of bolt sizes and wrenches, parts labeling, study of complicated tasks, etc).

Another idea: Carefully study the OEM's technical information letters (TILs) to identify which must be done and those that can be skipped or postponed. One of your primary reasons for attending the 7EA meeting is to get lessons-learned experience from others who have implemented TILs. This is invaluable information for your overhaul efforts.

OEM-recommended upgrades also should be scrutinized carefully. What might have seemed like a good idea a year ago in terms of capacity and heat-rate improvements, may no longer pass the financial litmus test because of changes to plant contracts for kilowatt-hours and ancillary services.

Pond next reviewed a long list of possible upgrades—such as B to E, 2055F, inner-barrel brush seal, honeycomb shroud blocks, etc—and explained to the group what gets changed and what you get for your money. The impact of upgrades on heat-recovery steam generator and Rankine cycle performance was included in this part of his presentation.

He also covered the benefits of steam injection (better heat rate and reduced NO_x emissions) and water injection (higher output and lower efficiency). Registered 7EA users can get the details by accessing Pond's presentation at the group's website, http://ge7ea.users-groups.com. If you're not registered, take a few minutes to do so and gain access to a rich library of information on your engines (see ad, p 105).

Inlet-guide-vane (IGV) upgrades were another item on Pond's menu. He discussed upgrading the vane material to high-flow GTD-450 to boost output by up to 1.5% and increase efficiency by 0.3% (the stronger material enables a smaller vane cross section). Increasing vane angle from 84 deg to 86 or 87 deg can add to the increase in power (although bushing wear may increase as well).

Caution: Be sure these upgrades would not be in violation of your air permit. Pond took a few minutes to remind attendees that IGVs can be changed with the rotor in place (www.combinedcyclejournal.com/archives.html, click 3Q/2006, click "Replacement of damaged lower IGVs. . ." on cover).

Ensuing discussion highlights included common maintenance issues—such as bucket life limits, transition piece failures (after about 40,000 hours of service), nozzle cooling-air tuning plugs, nozzle creep, No. 2 bearing issues, ice damage, etc.

Another best practice: Analyze operating data before you take the unit out of service for the outage. The information gathered will enable you to establish contract benchmarks for "no loss in performance" and to confirm improvements promised by upgrades.

The final step is writing the RFQ (request for quote). Pond stressed spelling out exactly what *is included* and what *is not included*. "Demand a quality job," he continued. Details are important: Specify bolt torques, stoning of joints and preserving serial numbers, parts inspection and completion of inspection forms, demonstration of instrumentation operability, and performance testing prior to job acceptance. One of your key goals is to write a tight contract to avoid charges for "extra work."

First-day highlights

Pond's workshop was the perfect segue to the meeting's first open discussion, which focused on outage planning and issues. Moderator for the session was Pat Myers, plant manager of Ceredo Generating Station and member of the 7EA Users Group steering committee (sidebar).

Expected lifetimes of critical parts was a hot topic. One user operating under one of the OEM's contractual service agreements (CSA) reported going to 900 starts before his engine's first CI. Transition pieces (TPs) and primary and secondary fuel nozzles were replaced; combustion liners met GE's acceptability criteria and were returned to service.

Unintended fallout of the CI included difficulty in achieving emissions compliance at low load (60%) following a cold start at low ambient temperatures.

Transfer out of premix was another problem encountered. A colleague suggested this might be caused by something as simple as an exhaust pressure transmitter out of calibration. However, he quickly added, finding the exact cause of the issue can be challenging. Another operator in the room suggested checking IGV schedule and conducting seasonal tuning when the cold weather hits.

Yet another participant opined that 900 starts between CIs is too aggressive; 600 was his recommendation. The discussion then moved to parts-life assumptions for outage planning and LTSA evaluation. No consensus was in evidence here, perhaps because of differences in firing temperatures and duty cycles among attendees.

One user with a 2025F machine said first bucket refurbishment should be at 24,000 or 48,000 hours depending on row. He thought first-stage blades were good for 96,000 hours, or more, based on having a row of second-stage buckets beyond 115K in a base-load engine. Four or five repair cycles were thought possible for first-stage buckets.

Then a question for the group: How many endorse the OEM's condition-based maintenance inspections? A wishy-washy response. One vocal non-supporter said such inspections take too long and slow down the outage, adding his belief that the OEM has a double standard: You may be told the parts are OK if you have an LTSA and not OK if you don't have a long-term agreement.

Another user said his company told GE to forget the inspection and change out combustion hardware the originally planned. However, the owner agreed to inspection of other HGP parts.

Several more discussion points of interest:

- Shims, shim liberation, etc. Consensus: Pinning took care of the problem without reworking the casing groove. The DRS Technologies solution (bladerepair@drs-pt.com) pioneered by Rodger Anderson was selected by several in the room; a couple of others opted for the GE method.
- The issue of cooling-hole plugging during bucket and nozzle refurbishment was raised. Best practice: Don't just punch holes; conduct a flow test as proof-positive that cooling passages are open. Failure to test could result in shorter lifetimes for critical airfoils.
- Combustion-wrapper leaks at the split line. Crush pins were suggested as one solution, shim stock between the wrapper and casing was another. One frustrated user resorted to welding joints after failing to stop leaks with increased torque.

Rod Shidler of Florida-based Advanced Turbine Support Inc, well known among Frame 7 users for his compelling presentations on the value of borescope inspections, reinforced Pond's comments the day before. He began by reviewing the reasons for periodic borescoping:

- Check for issues identified in TILs to prevent engine damage—such as stator-vane shim migration (TIL 1562) and Stage R17 blade movement (TIL 1090-2R1).
- Assess unit condition. For example, inspect for evidence of corrosion and erosion as well as for stator-vane movement/stepping.

- Identify necessary tasks in support of predictive/condition-based maintenance.
- Troubleshooting. Identifying the reason for increased machine vibration is one example.
- Verify cleanliness after a major outage to prevent foreign object damage (FOD) on restart.

Shidler's presentations help owner/operators better understand the capabilities of top-notch borescope technicians, where problems are likely to surface, and what the typical damage looks like. At the 7EA meeting he showed borescope photos profiling a compressor inlet condition assessment that focused on the IGVs (TIL 1132-2R1)—specifically tip rubs—and impact damage associated with R1 blades.

The results of R1 to S1 clashing identified in last year's report referenced earlier were clearly visible in more photos, as were blade rubs conducive to tip liberation. Other photos showed S1 vane cracks, shim migration, mid to aft compressor rubs, R17 blade movement, etc. All are on file in the library on the group's website.

OEM viewpoint

GE's team of speakers were well prepared and covered a great deal of subject matter within about two and a half hours of podium time, including the following:

- Update on the OEM's R17 blade-failure root cause analysis (RCA).
- R1 to S1 clashing RCA update.
- Inlet fogging/wet compression for power augmentation.
- End of life options.
- Emissions reduction developments.
- Repair technologies update.
- Controls obsolescence planning.
- Fuel flexibility update.

Certainly something for everyone. The first three bullet points were of particular interest to most in attendance and were subjects covered thoroughly in later user and special vendor (non OEM) presentations.

A GE speaker confidently dismissed R17 failures as something in the past, only one having occurred since 2003. He described the last R17 "event," which happened in 2008 on a simple-cycle engine with only 720 fired hours,153 fired starts, and eight trips. Cause reportedly was a fatigue crack initiating from fretting damage that was propagated via high-cycle fatigue. Corrosion was considered a factor in the failure.

The OEM considered the R17 issue an "infant-mortality" type of incident because only one of the 14 reported failures occurred after 1200 hours. Speaker said the "fix" was use of a dovetail undercut on R17 blades. It was specially developed to address the corrosion possibility. GE recommended that the engine owner replace R17 blades fleet-wide at the next CI.

R1/S1 clashing was quickly addressed. There had been 12 incidents reported at five sites but no forced outages resulted. In most cases the R1 blades had no damage. Suggestion was to "catch" clashing early and restake to prevent further migration.

The OEM's position on fogging was that droplets larger than 10 microns may cause compressor erosion and fogging nozzles may not atomize to the degree necessary to achieve that goal; further that nozzle plugging might cause uneven fogging patterns and fine droplets may agglomerate to more than 10 microns during operation. Nothing new here.

Interestingly, fogging—even overfogging (wet compression)—is viewed positively by several 7 B-EA owner/operators, including a couple of major utilities. For more on this subject, see the section on fogging in the report on air inlet systems (p 43) and articles referenced within that passage.

Other presentations

A representative of the owner of the machine described in the OEM section above as having had the R17 event in 2008 also presented in Miami. He gave more detail on the unit and about what happened. The 7EA, while dual-fuel capable, had burned only gas. It is equipped with inlet bleed heat and inlet fogging.

The unit tripped in the early evening, while operating at base load (95 MW), because of a drop in compressor discharge pressure and combustion trouble. The trip was followed by approximately 15 seconds of high turbine vibration (peak was 2.6 in./sec). Ambient temperature was 13F.

Shop work included replacement of R16 and R17 blades and S15, S16, S17, EGV1 and EGV2 airfoils, inspection of TPs, repair of combustion liners, etc. Presentation posted on the group's website includes photos.

The same user presented on S1/R1 collisions on five of six 7EAs at the site where the R17 event occurred. Collision indications were found in April 2008 and only at the 6 o'clock position. Clashing in the sixth unit was identified a year later during a borescope inspection. The engine had operated only 60 hours (20 starts) since the previous inspection when it received a clean bill of health.

Several other plants in Texas, Illinois, West Virginia, Virginia, and Ohio reported similar findings. The value of user collaboration certainly stands out here.

The speaker reported that the OEM initially considered clashing insignificant in terms of posing a risk to continued operation. It advised that the damaged areas be examined by fluorescent penetrant inspection, blended smooth, polished, and flapper-peened by a qualified OEM technician at the next opportunity.

The manufacturer was not sure what might be causing clashing and considered that it might be a system-level assembly issue that caused casing distortion or concentricity/alignment offset.

After clashing was identified on F-class machines—suspected cause was compressor surge and/or stalls—the OEM got actively involved in an RCA for the 7EA issue. Details of each incident the presenter was familiar with, complete with photos, are available on the group's website.

Other user presentations from the Miami meeting posted on the website include these:

- Exhaust section cracking and repair solutions.
- Ratchet versus spin cooling and the effects on No. 1 bearing life.
- Protective relay plant reliability project.

The last formed the basis for an entry in the COMBINED CYCLE Journal's Best Practices Awards program which earned Ceredo Generating Station Best of the Best recognition last spring. Access www.combinedcyclejournal.com/archives.html, click 1Q/2010, click "O&M: Balance of Plant" on the magazine cover.

Alternatively, you can download a 10-min presentation on the topic (voice over PowerPoint) at www.ctotf.org. Register at the website to gain access to the Internet Bulletin Board Communication Service (IBBCS). Scroll down to the Presentation Library and then scroll to "AEP; Ceredo Protective Relay Project."

Finally, presentations by consultants and vendors available for review are:

- State-of-the-art repair techniques: Practical experience with the development of superalloy rejuvenation (Liburdi Turbine Services Inc).
- Wet compression technology for the 7EA (Caldwell Energy Co).
- State of the 7EA fleet as compiled from the ORAP database (Strategic Power Systems). CCJ

CTOTF emerges as an industry leader

The electric power industry has changed dramatically over the last quarter century. It was about 25 years ago when the non-utility generation business created by the passage of Purpa (Public Utility Regulatory Policies Act) in 1978 began to gain traction.

In 1985, approximately 90% of the power generated in the US was produced by regulated investor-owned (IOU) and public utilities. The latter group includes municipals, cooperatives, and federal and state agencies. Industrial companies and institutions produced for internal consumption most of the kilowatt-hours that the utilities did not generate.

Vertically integrated (generation, transmission, distribution) IOUs had the swagger back then, owning roughly three-quarters of the nation's generating capacity; their industry trade association, the Edison Electric Institute, was a powerful political force. Utilities were rock-solid financially and their stocks underpinned many pension plans.

Important 1985 industry stats, as reported by the Energy Information Administration: 655,200 MW (total net summer capacity for all generators); gas turbines accounted for slightly more than 7% of the installed capacity; coal-fired plants produced 57% of the nation's kilowatt-hours.

Fast forward to 2009: 998,200 MW; gas-turbine-based plants (including steam-turbine capability at combined-cycle plants) accounted for more than 35% of total installed capacity; coal-fired plants produced 46% of the nation's kilowatt-hours.

So, while many of the graying attendees seen at industry meetings were building their careers designing, building, constructing, and maintaining generation infrastructure, the industry they served was roiling underfoot and evolving from an electric *utility* industry to the electric *power* industry it is today.

Evolution. Perhaps difficult for some to believe, but in the last 25 years, while the nation's generating capacity grew by 52%, the net sum-

1. How to get your 'card' to access the CTOTF Presentation Library

Step 1: Access www.ctotf.org.

2. Click on the "New Member" button on the horizontal toolbar at the top of the page.
3. Complete and submit the online membership registration form.
4. Confirmation of your acceptance as a CTOTF member with full IBBCS (Internet Bulletin Board Communications Service) privileges generally will be e-mailed to you within 72 hours.

As a member, go to www.ctotf.org, and click the flashing link "Free Online Bulletin Board Service." Next, scroll down the page to "Presentation Library" and click on that link. Presentations are arranged in chronological order, by meeting, most recent first. So it's easy to find any presentation referenced in the COMBINED CYCLE Journal.

When you click on a presentation, the first information that pops up is the complete title of that presentation, the name of the presenter, and an abstract. The PowerPoint slides are accessed by clicking the word "here" under the abstract—as directed. After you have reviewed a presentation, you may want additional information. Return to the abstract page and access the presenter's website by clicking the link after his or her name.

mer capability of electric utilities *decreased* by about 12%, coal-fired generation lost significant market share, and gas-turbine-based capacity increased about five-fold.

Today, the US has more generating capability at facilities powered by gas turbines than it does at those fueled by coal. And non-utility generators now control 43% of the nation's power-production assets.

CTOTF. The Combustion Turbine Operations Task Force, celebrating its 35th anniversary this year, has been there for the entire ride and has reinvented itself in much the same way the industry has. In its formative years, the group was affiliated with EEI, reporting into the Steam and Combustion Turbine Subcommittee of the Prime Movers Committee.

But EEI's reorganization in 1995 loosed the association's technical committees and John Lovelace, then CTOTF chair, transitioned the group to an independent organization controlled by GT users. He recruited dedicated owner/operators nationwide to help build CTOTF into the most comprehensive GT user meeting in the world.

The group took another big step forward when Lovelace retired in spring 2008 and Robert G Kirn, currently senior manager for business ventures at TVA, was elected chairman. The group reorganized, adding three executive vice-chair positions to facilitate decision-making in the growing organization (refer to chart, p 126).

With veterans Eddie Mims, Ray deBerge, and Richard Evans (replaced by Jack Borsch in 2009) in place, Kirn was able to expand CTOTF's franchise beyond the gas turbine itself. The result: Meetings customized to the total information needs of powerplant supervisors and managers. Incidentally, each of the executive vice chairs experienced the entire 1985-2010 industry transition described above.

"While CTOTF will continue to emphasize the 'nuts and bolts' of the

2. 2011 Best Practices Awards

Enter today while the accomplishments of plant personnel are fresh in your mind

One way to get management's attention long enough to appreciate the contributions you and your co-workers are making on a daily basis is to win an industry award. The Best Practices Awards program conducted by the COMBINED CYCLE Journal, in association with the Combustion Turbine Operations Task Force (CTOTF), recognizes ideas implemented by plant personnel to increase reliability/availability, improve efficiency, reduce emissions, minimize accidents, etc. Such performance improvements are important to every owner and its management team.

To enter the 2011 Best Practices Awards competition, access the requirements/rules page at www.psimedia.info/bestpractices.htm. The program supports work done in gas-turbine-powered combined-cycle, cogeneration, and peaking plants larger than 5 MW. There are seven awards categories: management, environmental stewardship, safety, design, and O&M business, major equipment, and balance of plant.

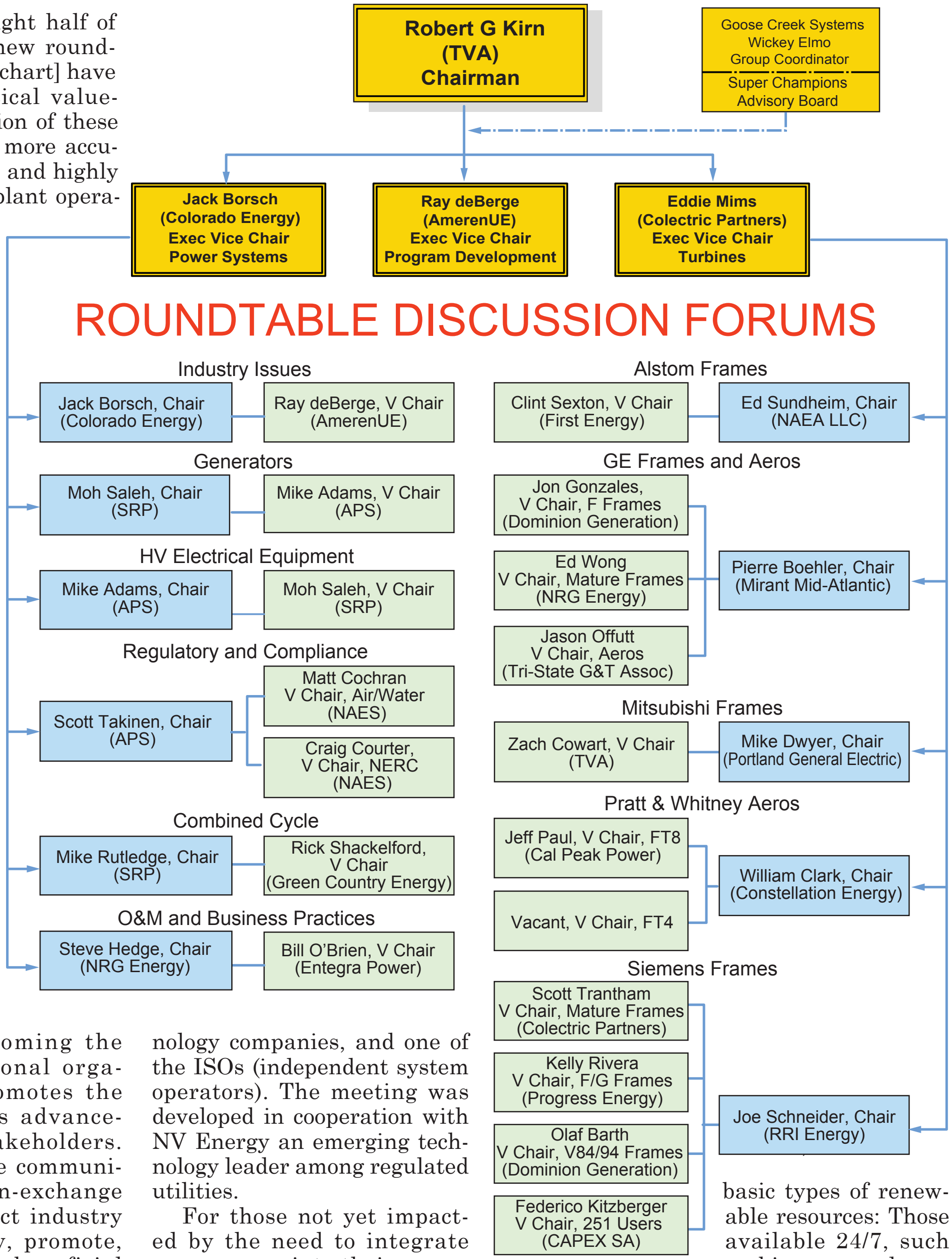
Your entry should take no more than two hours to prepare and e-mail to scott@psimedia.info. Photos and diagrams explaining the work done, plus a picture of your plant, are welcome. The deadline is Dec 31, 2010, but don't wait: Prepare the entry today, while the accomplishments are fresh in your mind.

Judging will be by a panel of experts from the CTOTF Leadership Committee.

centerline equipment [right half of the org chart], several new roundtables [left half of the org chart] have been introduced as critical valueads," Kirn said. "The union of these subjects and discussions more accurately reflects the overall and highly dynamic needs of powerplant operations today."

Obvious to the CTOTF membership was that in the shift from an electric utility industry to electric power industry, the technical leadership once provided by top utility executives—people like AEP's Phil Sporn and Duke Power's Bill Lee—was severely compromised.

Executives at generating companies today typically have financial or legal backgrounds and sometimes seem reluctant to accept that fact that continued technology development is critical to their companies' long-term health. Xenophobic may be the best way to describe some boardrooms—particularly in the non-utility sector. This generally is not the case in regulated companies, which remain reasonably transparent.



That in mind, CTOTF set about becoming the international professional organization that best promotes the technical and business advancement of generation stakeholders. Its mission is to provide communications and information-exchange mechanisms that connect industry participants to identify, promote, and facilitate mutually beneficial business value.

Integrating renewables

One of the group's initiatives is to keep managers of conventional generation assets current regarding how increasing amounts of power from renewables may influence the operation, maintenance, and lifetimes of existing assets.

"Integrating Renewables Into the Generation Mix: Challenges and Unknowns," a one-day workshop held September 13 in Reno, was a big step forward, with speakers and panelists from regulated and unregulated generating companies, transmission and distribution organizations, technology companies, and one of the ISOs (independent system operators). The meeting was developed in cooperation with NV Energy an emerging technology leader among regulated utilities.

For those not yet impacted by the need to integrate green power into their operations, note that 31 states already have so-called Renewable Portfolio Standards (RPS) in place (June 2010 data). These laws typically mandate that between 20 and 30% of a utility's kilowatt-hours must come from renewable resources by 2020—earlier in some states, later in others.

The bases for the percentages specified by the RPSs sometimes are politically motivated and not well defined, and often are not driven by specific research to justify the numbers. To someone with limited experience in electric power systems, a 20% RPS may not seem like the challenge it really can be.

Consider for a moment the two basic types of renewable resources: Those available 24/7, such as biomass and geothermal, and those that are intermittent, like wind and solar.

Experience to date indicates that wind—the preferred renewable resource based on installed capacity and planned additions—often does not blow when power is needed most. In fact, wind generation may be at its peak in the evening, when demand is lowest.

To meet the RPS, utilities without bulk energy-storage assets must send out renewable power as it is produced. At night or during the shoulder months, kilowatt-hours from renewables can be as much as 50% of the total energy supplied—possibly even more.

Mother Nature may be somewhat

predictable, but not entirely so. This dictates the need for back-up generation resources, energy from neighbors via the grid, load shedding, and/or other *immediate* solution to compensate for the shortfall in energy production from renewables.

Where fast-start/rapid-ramp assets are optimal for backing-up renewables, or at least part of the solution, gas turbines are the likely generation option and the reason CTOTF decided to host this workshop. A full report on the information disseminated will be published in the next issue of the COMBINED CYCLE Journal, and available at the beginning of November at www.ctotf.org.

It's important for GT owner/operators to follow RPS developments in areas where their plants are located. Specifically, pay attention to the debate on the proposed national RPS. If such a law is enacted it could cause a paradigm shift in the generation sector akin to that created by the passage of Purpa more than 30 years ago.

Outreach

A robust website is critical to the success of any industry organization. Relatively few users can get to meetings on a regular basis, many being tied to their respective facilities because staffing is thin and there's no backup. The CTOTF Leadership Committee understands this reality and reaches out to all GT users via www.ctotf.org.

The group's bulletin board was created by Michael Elmo of Goose Creek Systems Inc, Indian Trail, NC, who has extensive experience in the development and implementation of computer-based systems—including nearly two decades of service with the Electric Power Research Institute (EPRI).

What sets this bulletin board apart from others hosted by the model-specific user groups is that access is available *free* to employees of any company with an equity interest in, or currently operating, *any* type of gas turbine.

Recently, Elmo enhanced the value of some PowerPoints posted to the keyword-searchable website. Specifically, he created voice-over PowerPoint (VOPP) files for each of the presentations made by recipients of the 2010 Best Practices Awards in the Best of the Best category.

The VOPP files, nominally 10 minutes long, are much better than silent slides, which often leave you guessing as to what the author was trying to get across. So, when you look through the awards presentation report on p 112 of this issue, remember that you can easily access and *listen to* details on each of 2010's top Best Practices at ctotf.org. If you are not yet a registered user, follow the instructions in Sidebar 1 to gain access. VOPP is a welcome new dimension in communications for GT owner/operators.

Don't forget to get your entries ready for the 2011 Best Practices competition. They must be submitted to the COMBINED CYCLE Journal by December 31 (Sidebar 2).

Another of Elmo's innovations is a method for incorporating photos into Bulletin Board communications. One of the early "adopters" was a W501FD1 user with questions concerning improperly seated compressor outlet guide vanes—so-called "stepping." A phenomenon like this would be difficult to describe in words, so he included five photos to show how stepping progressed over several years.

Think of the possibilities with this capability. Now you can broadcast your inspection findings visually to get a fleet-wide consensus without leaving the plant.

Web guide

The CTOTF Spring and Fall Turbine Forums each feature 60 or more hours of presentations and open discussion during the four days of the meeting. One person from your company cannot get to all of the sessions ("roundtables" in CTOTF speak), you need at least two, sometimes three. The most efficient way to disseminate all that information is via the Web.

Elmo has posted formal presentations from the 2010 Spring Turbine Forum to the Presentation Library at www.ctotf.org (refer again to Sidebar 1), which is arranged in chronological order by meeting (most recent first). It's easy to log on and peruse this material by roundtable, but that might not be the most efficient way to find subject matter of interest.

Intent of the "Web guide" below is to help you quickly identify information from the spring meeting of current value—this to minimize the time spent navigating through the library. It is organized by roundtable.

Industry issues. Fundamentals of natural gas trading (R Trinnear, The Energy Authority); presentations by recipients of the top Best Practices Awards (pages 115, 116),

Rose retires from one career to begin another

Dominion Generation's Larry Rose received a well-deserved "hero's" sendoff into retirement from his first career by the CTOTF membership at the group's 2010 Spring Turbine Forum on Amelia Island, Fla. Executive Vice Chair Ray deBerge presented Rose the John B Lovelace Award "for extraordinary contributions to the power-generation industry and the Combustion Turbine Operations Task Force." Lovelace, who retired in 2008 after holding the CTOTF chairman's position for 17 years, came all the way from Phoenix to wish his former colleague well (photo).

Rose was a positive force in the industry for 40 years, spending virtually his entire career as a gas-turbine engineer. He started professional life as a co-op student assigned to commissioning of Virginia Electric & Power Co W191 and W251AA engines. VEPCo later became Dominion Energy.

The editors recall Rose as a gentleman's gentleman with a sharp analytical mind. He never raised his voice, was unflappable, always had time to listen to someone else's ideas and opinions, and never jumped to conclusions.

Rose told the editors his second career would begin immediately. He had a couple of years worth of residential (his) construction projects lined up and had promised to direct church-related O&M activities. There were several more things on his list as well.

Paul White, PE, Dominion Generation's manager of O&M, shared with the editors some of Rose's professional accomplishments, but even White's abbreviated list was much too long to publish here. A couple of examples of Rose's groundbreaking work on behalf of his employer, and the industry at large, follow:

- Optimization of start times and loading cycles on 7EA peakers to meet 10-min reserve requirements.
- Development (in his spare time) of a corporate computer-based maintenance management program that served the company until its transition to SAP about 10 years ago.
- Pioneered combined-cycle performance analysis as a charter member of the GATE Cycle project team. Today that software is a standard prediction tool throughout the GE fleet.
- Intimate involvement in GE F-technology development. Recall that the first 7F was deployed as a prototype at VEPCo's Chesterfield Station. Rose collaborated with the OEM to develop the original 7F swirl chart, pushed GE to pioneer rainbow TBC tests in the first-stage turbine airfoils, survived the first maintenance interval of 7F "teething" issues, oversaw the early replacement of the "test 7EA style" turbine rotor with the first GEN1 7F turbine rotor, etc.
- Worked through 7EA compressor S17 issues and transitioned the solution to the two Chesterfield 7Fs, only to see the original weakness reappear again in early 7FAs.
- Grew the GT technical support group at Dominion from just himself into an effective team while playing a significant role in the development of best practices and in the mentoring of new engineers.

In addition, Rose still found the time to share his knowledge with colleagues as an active participant in CTOTF, CTC^2, 7F, 7EA, 501D5/D5A, and Alstom user conferences.

Larry Rose (left) is welcomed into retirement by John Lovelace

including representatives from the following companies/plants: AEP/Ceredo, Brazos/Jack County, NV Energy/Higgins, Mackinaw Power/Effingham, SRP/Desert Basin, GDF Suez Energy/Hopewell, Tenaska Virginia.

O&M and business practices. Remote operation of simple-cycle GTs (E Wong, PE, NRG Texas); High-energy piping inspection and maintenance programs (J Frey, PE, Stress Engineering Services Inc).

GE. Fact sheets for Frames 5, 6, 7B, 7EA, 7FA, and 9 (various GE authors); Latest GE 7FA compressor issues (R Shidler, ATS-Advanced Turbine Support Inc).

Combined cycle. FAC in combined-cycle HRSGs, Grade 91 material (both by J Frey, PE, Stress Engineering Services Inc); HRSG chemistry control (J Witherow, HRST chemistry consultant).

Pratt & Whitney. Predictive analytics: Eliminate critical equipment failure (P Flesch, SmartSignal Corp); DAX generator exciter armature inspection procedure; Brush aftermarket Americas service and support (both by C Mallon and J Alexander, Brush Turbogenerators Inc).

Regulatory and compliance. CEMS: Life cycle management (S DeVita, Teledyne Monitor Labs Inc).

Alstom. Experience with rejuvenation repair of an Alstom 11N2 hot section (K Weins, PE, Liburdi Turbine Services Inc); Alstom vane-carrier repairs: Challenges and solutions (M Walton and W Greaves, Sulzer Turbo Services).

Siemens. Gas-turbine rotor requalification inspections: Recent experience with a Siemens rotor; Preliminary results of the W501B6 third-stage turbine-wheel engineering analysis (both by R Curtis, Eta Technologies LLC and J Schneider, RRI Energy Inc); Field conversion of mature powerplant gas turbines to low-emissions combustion and control systems (D Stephens, PSM); Introduction of a breakthrough HEPA inlet air filtration technology (S Medvetz, W L Gore & Associates LLC); Mature-frame Westinghouse capabilities, parts, and services (D May, TurboCare).

HV Electrical. Extending the life and efficiency of your isolated phase bus—the hidden truth (E & J Netter, Electrical Builders Inc); Operation and maintenance of vented lead-acid batteries (M Adams, Arizona Public Service Co).

GE Aero. Changes to GEK (Vol 1, Table 12-1) and VSV calibration procedure (D Reed, RSI-Reed Services Inc).

Generators. Hydrogen leak detection (M Saleh, SRP); Current generator issues (J Lau, Siemens Energy); Effect of cycling on generators (R Zawoysky, GE Energy). CCJ

Improve reliability of gas turbines on liquid fuels

Will your dual-fuel gas turbine (GT) start on distillate the next time you hit the button? Will your engine transfer to oil from gas without tripping offline the next time you switch fuels?

Good questions that many operations personnel would like to answer with a positive "yes," but can't. There are several reasons why plants often experience poor reliability on liquid-fuel starts and on fuel transfers, including these:

- Ineffective procedures for assuring high availability of the liquid-fuel system. Diligent maintenance and regular "exercise" of all system components are particularly important.
- Inadequate training of O&M personnel. Liquid-fuel systems cannot be an afterthought; they command respect.
- Off-spec fuel, either through purchase or deterioration in storage.
- Coking of oil in piping and valves located close to hot engine parts.
- Check valves do not reseat properly.

First three items are well within the plant's control. A solid dose of commitment is all that's needed in most cases. The last two also are within the plant's control—at least for facilities equipped with dual-fuel GE Frame 6, 7, and 9 DLN engines (including F class)—but they require a small investment either in new hardware or modification of existing equipment.

You may recall that the first liquid-fuel systems for dual-fuel DLN engines had separate valves for fuel and purge air (Fig 1). Also, that purge air is supplied continuously when the turbine is operating on gas; it is turned off when operating on oil.

Liquid-fuel check valves are prone to coking because of their close proximity to the engines served. Simply put, the light fractions in the small amount of oil that remains in the valve when the unit transfers to gas distills off, leaving a carbonaceous residue which could impede valve operation on ensuing starts and fuel transfers. Residue accumulates with each start and fuel transfer, often preventing proper seating of the check valve when oil firing ends.

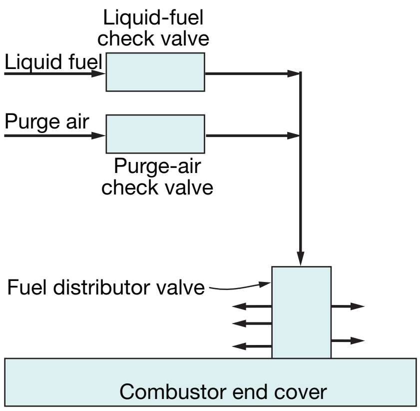
When this occurs, purge air and combustion gases can travel all the way back through the oil piping to the flow divider, and beyond, causing fuel system evacuation, corrosion of the flow divider, and other issues. Units experiencing this condition are prone to tripping on the next attempt (1) to start on liquid fuel or (2) to transfer from gas to liquid fuel (no fuel in the line connecting the flow divider to the check valve).

McElrath

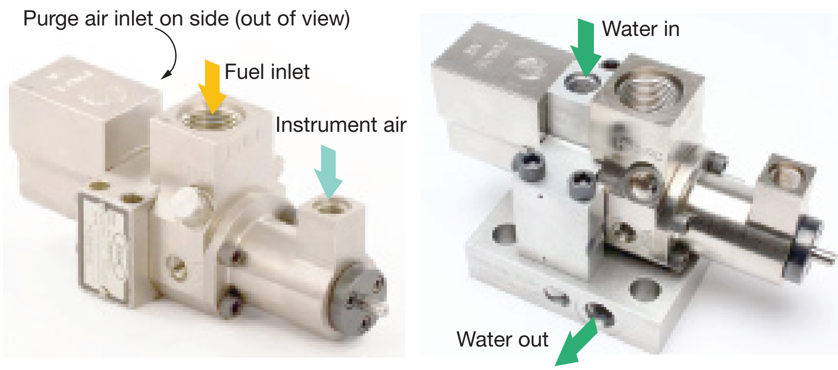
Jansen

One of the steps undertaken by the OEM to improve the reliability of its dual-fuel DLN frames was to combine the functions of the liquid-fuel and purge-air check valves into one valve body. Today, the three-way purge valve (3WPV) is standard equipment on DLN-equipped Frame 6, 7, and 9 engines (Fig 2). About 5000 of the valves, made by Jansen's Aircraft Systems Controls Inc (JASC), Tempe, Ariz, are installed worldwide.

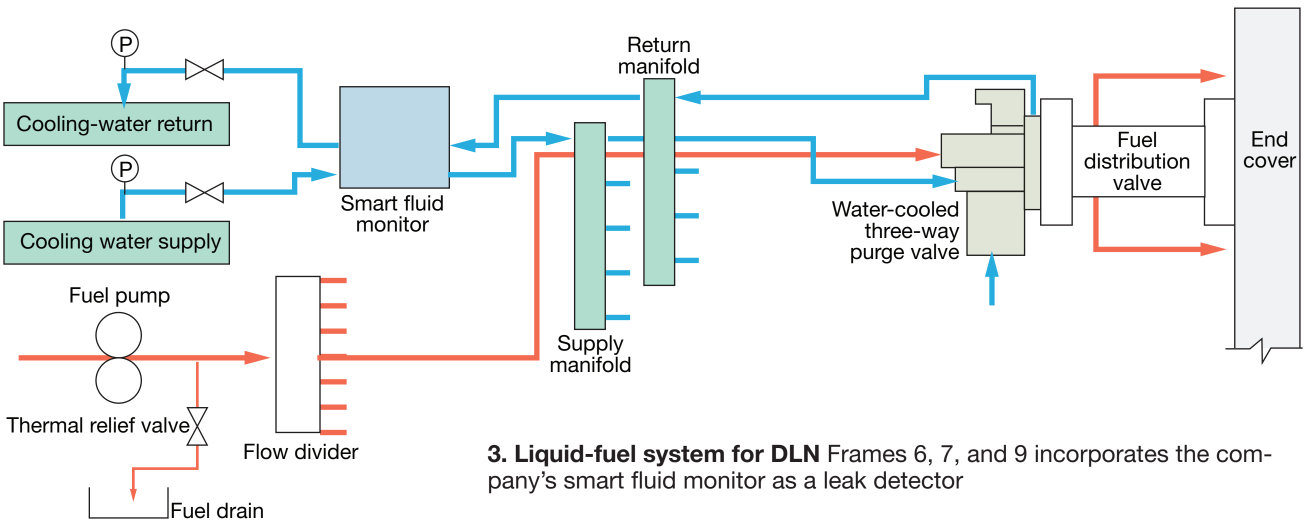
Scores of GTs still are equipped with individual liquid-fuel and purge-air valves and most would benefit from conversion to the 3WPV. However, there's no stampede, according to Schuyler McElrath, because problems associated with



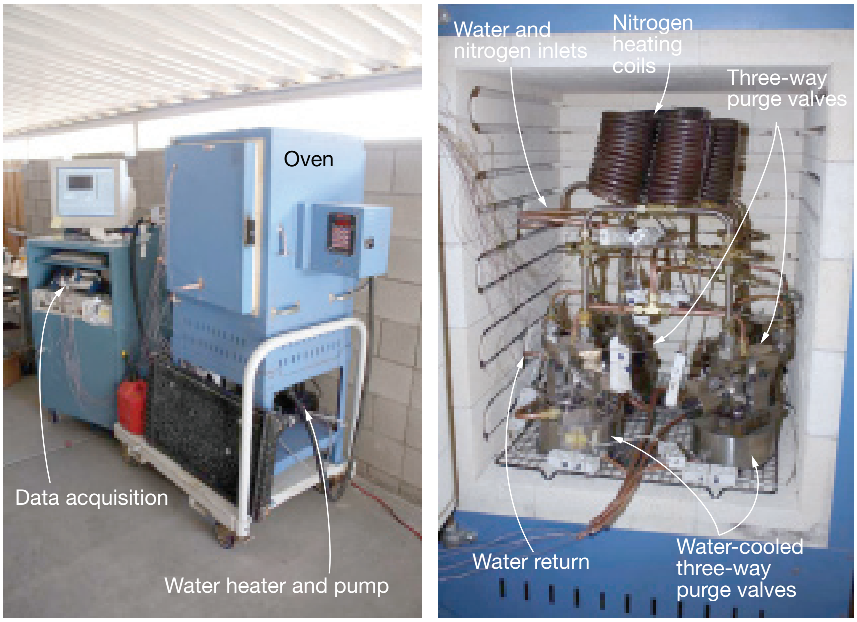
1. Liquid-fuel systems for GE Frames 6, 7, and 9 initially were equipped with separate fuel and purge-air check valves. These liquid-fuel check valves were not cooled and often were compromised operationally by coking issues



2. The three-way purge valve was a significant advancement in fluid handling technology because it combined the liquid-fuel and purge-air valves in one unit and improved system reliability (left). But coking remained an issue for many owner/operators. JASC's solution was to incorporate a water-cooling circuit into the valve as it had successfully done for the standalone liquid-fuel check valve a few years ago (right)



3. Liquid-fuel system for DLN Frames 6, 7, and 9 incorporates the company's smart fluid monitor as a leak detector



4. Test setup to measure the effectiveness of the water cooling circuit reflects the practical approach to engineering problem-solving championed by JASC President Harvey Jansen. Entire test rig is at left, oven at right

distillate firing have caused many engine owner/operators to just give up on oil. Even the 3WPV is subject to coking problems.

By way of background, McElrath spent nearly 25 years working on fuel systems for the OEM before starting his own company, SMTC Inc, Greenville, SC. He spends much of his time helping users solve liquid-fuel problems on behalf of JASC.

Recognizing the paralyzing effect coking was having on GTs, JASC President Harvey Jansen, a pioneer in high-tech fluid-flow solutions for the aerospace industry, went "all-in" on the company's ability to develop a "cool" liquid-fuel check valve.

Nearly four years ago, following successful beta tests at a refinery, the company began offering a water-cooled version of the liquid-fuel check valve (WCLFCV). These GE-approved valves now are installed on more than 100 engines worldwide. McElrath reports virtual 100% reliability on starts and fuel transfers.

The next logical step was to develop a water-cooled three-way purge valve (WC3WPV), shown integrated into the liquid-fuel system in Fig 3. A WC3WPV was required because GT owners using this technology needed an inexpensive way to achieve liquid fuel system reliability.

Piece of cake considering the company's proven success with the WCLFCV. But Jansen, who epotimizes the iconic American technology/business leaders Thomas A Edison and Edwin Land (Polaroid), was concerned more about cost than simply designing a water-cooled valve.

JASC engineers responded with a method for converting existing 3WPVs to water-cooled valves for about one-third the cost of a new valve. Next step was to run validation tests in the lab. The test rig was similar to that used for proof-of-concept tests on the WCLFCV (Fig 4). Photo shows that two uncooled and two water-cooled valves were tested simultaneously.

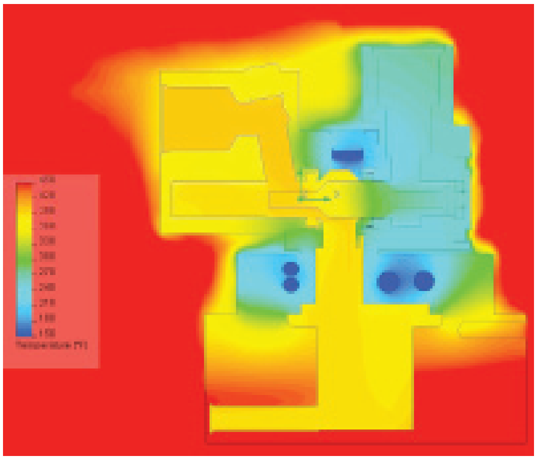
McElrath called in early August to say that the test results detailed in the "Design Verification Test Report" prepared by Project Engineer Kirby Meyer had been accepted by Jansen at the end of July and they proved that the valve was ready for commercial application. The WC3WPV is scheduled for installation on operating engines this fall.

JASC has a rotable pool of valves to swap out with existing 3WPVs—one or two per combustor for a GE frame, depending on the model being upgraded. McElrath says that the valves can be changed out and the water supply and return circuits installed over a weekend.

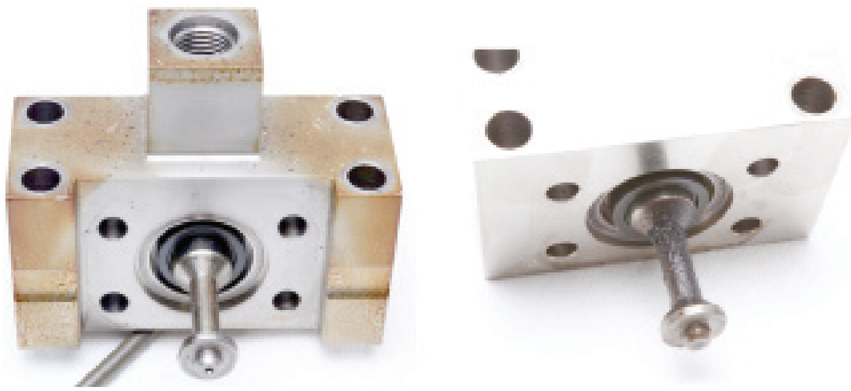
By contrast, it typically takes about two weeks to convert a turbine outfitted with 3WPVs back to a configuration which uses check valves. The extensive changes that must be made to purge-air and fuel piping are labor intensive.

Lab tests were conducted in an environment far more challenging than the one that exists in a GT package and the results exceeded expectations, McElrath said. For example, the thermal profile of a WC3WPV in Fig 5 reflects purge air at 400F, well above the normal operating service temperature of about 230F.

Note that the purge "air" for testing purposes in the first phase of the testing program actually was nitrogen heated in the coils located at the top of the furnace (right side of Fig 4).



5. Thermal profile of the water-cooled three-way purge valve is shown for a purge-air temperature of 400F, which is far above the normal operating temperature in gas-turbine service of about 230F. Hottest fuel temperature on this run was 292F; average fuel temperature was 240F. Ambient (oven) temperature was 475F, cooling water was at 150F, flow 2 gpm. For another run, with purge air at 300F, the hottest fuel got was 243F and the average fuel temperature was 218F



6. Cool means clean. After 80 hours in the oven, the spool for the water-cooled three-way purge valve looked almost new (left); that for the uncooled valve showed significant buildup of crud (right)

This was done to mitigate any safety concerns associated with a mixture of air and fuel at the auto ignition threshold of diesel oil.

Highest fuel temperature on this run was 292F, the average fuel temperature 240F. The threshold for coke formation is 250F. Regarding the fuel, slightly more than half an ounce (specifically, 20 cc) of No. 2 oil was injected into each of the four valves. Oil was added daily to replenish fuel that had distilled off and was safely vented.

Another test with purge air at 300F, still 70 deg F over normal operating temperature, revealed an average fuel temperature at only 218F. For both runs, the oven temperature was 475F, cooling water 150F (flow rate, 2 gpm).

The test program had two major parts:

- A two-day trial with extensive data collection, followed by trending of the data to assure that the test rig would produce the information required to validate (or not) the design of the water-cooled valve.
- A two-week test with about 80 hours of active oven time to assess coking tendency. For this test segment, nitrogen simulation of purge air was shut off and oven temperature increased to 550F to induce as much coking as possible.

The two WC3WPVs were monitored continuously to ensure that valve temperature did not exceed 250F. Average temperature of the valves' spool sections during the two-week run was about 220F.

Over the two-week period, about 6 cc of distillate was added daily to replenish the two 3WPVs, compared to only 1 cc for the water-cooled valves. Consequently, considerable fouling was observed on the spools for the standard valves (right photo in Fig 6); the spools for the water-cooled valves were clean by comparison (left-hand photo).

Finally, regarding tightness of WC3WPV shutoff, expectations were surpassed. Better than an ANSI Class VI seal was achieved. More specifically, the WC3WPV spool seal was bubble-tight using 300-psig nitrogen.

To dig deeper into the details of the validation test program for the WC3WPV, access www.jasc-controls.com. CCJ

Third-party shops expand HGP repair capabilities

The expectation that gas turbines (GTs) will maintain their dominant position in the electric-power generation sector well into the future has helped motivate significant recent investment in repair facilities for hot-gas-path (HGP) parts. The lion's share of this investment has been in third-party shops, much of it for state-of-the-art inspection and machine tools.

Economics 101 teaches that competition drives innovation and that's certainly true when it comes to HGP repairs. In fact, it's probably fair to assume that third-party shops lead the industry in level of repair sophistication and capabilities. Two facts that support this assumption:

- User group meetings offer a continual stream of case histories that follow this story line: Third-party shop performs the repairs that were not possible in the OEM's view, saving parts from the scrap heap; repaired parts successfully complete another maintenance interval.
- OEMs are buying up independent shops. Examples include acquisitions by Siemens Energy of TurboCare Inc, by Dresser-Rand of Leading Edge Turbine Technologies Inc, and by Alstom of Power Systems Manufacturing LLC.

Of course, the term third-party doesn't tell the entire story. Several third-party repair organizations actually are OEMs. For example, Pratt & Whitney Power Systems (PWPS), known for its aero engines, relies on the company's extensive GT experience to repair frame engine parts at its San Antonio facility; Alstom repairs parts made by its frame competitors at the PSM shop in Jupiter, Fla; Mitsubishi Power Systems Americas repairs the parts of frame competitors in its Orlando shop, etc.

With all the activity in this sector of the market, if you have been out of touch with any repair shop for more than about a year it's reasonable to believe there have been significant changes. If there have been none, that's significant, too, because it may mean competitors are now more capable. Keep in mind that hardware is not the only variable of importance: Highly skilled people come and go. This is especially true in times of industry expansion.

Between the 1Q and 2Q issues, several shop-related events took place, including the following: Allied Power Group LLC merged all of its offices and storage and shops into a new 75,000-ft^2 building on 14 acres in Houston and dedicated the facility; Phoenix Turbine LLC, Gilbert, Ariz, held an open house to show off its new capabilities; and the editors visited PWPS during the Frame 6 User Group meeting in San Antonio.

New shop repairs, makes HGP parts for wide range of GTs

Phoenix Turbine LLC's open house at its new repair and manufacturing facility in Gilbert, Ariz, attracted gas-turbine experts from across the Southwest. Utility and independent power producers with reservations for the recent shop tour and Texas-style BBQ lunch included Arizona Public Service Co, Arizona Electric Power Co-op Inc, Calpine Corp, Dow Chemical Corp, NV Energy, Salt River Project, and Tucson Electric Co.

The meticulous 20,000 ft^2 shop reflects a significant move by the company to expand its menu of services to owner/operators of F-class machines while maintaining expertise in older units, and smaller ones as well. Phoenix Turbine is one of several repair facilities pursuing F-class opportunities. With many of these engines coming up on a decade of operation, and owners stepping back from OEM long-term service agreements, having a larger shop allows Phoenix to capitalize on economies of scale in component repair and manufacturing.

To fill the repair and manufacturing center, the company hired F-class repair veteran Todd Dunlop as director of sales. Strategy of the managing partners—Bob Harrison, Joe Girmonde, and Allen Brackett—is simple: Make repairs and new parts faster, better, and at lower cost than the competition. A wide range of new parts is already on the shelves, and with added inspection and repair capabilities additional shop space already is under consideration.

Senior operations personnel may recall Harrison's deep experience in GT repairs. Before Phoenix, he served as president and general manager of Chromalloy Heavy Industrial Turbines and founded Industrial Turbine Technology (ITT), which eventually became Wood Group HIT Ltd.

New parts. The company has two main lines of business: manufacture and repair of hot-gas-path (HGP) parts. Core competencies include the cost-effective production of shroud blocks for all GE frames through 7FA (plus Frame 9), and transition pieces (TPs) for the Siemens W501s (AAs through D5As). Plus, TP floating seals, clamshells, baskets, crossfire tubes, segment seals, spring seals, and other consumables specific to one or more Siemens and GE engines (Fig A1).

Repair capabilities are enabled by state-of-the-art welding and machine tools. Personnel have expertise in TIG, gas metal arc, and shielded metal arc welding. Tooling for the new shop includes form and fit and dimensional-check fixtures for all major components, four-axis EDM, horizontal and vertical boring mills, large lathes, etc.

State-of-the-art tooling and experienced personnel assure quality turbine blade/bucket repair, including tip and angel wing restoration; vane and nozzle repair with DSD correction; complete restoration services for combustion liners and TPs; restoration of compressor blades and diaphragms; welding, heat treatment, and machining of nozzle support and vane segment rings; shroud block and ring segment repairs, etc.

Specialties include repair and refurbishment of W501F combustion baskets and R1-R4 blades and vanes for the W501AA and the W501D5-D5A. For GE Frames 3, 5, 6, and 7B-EA, repairs of Stage 1, 2, and 3 nozzles and buckets, as well as of liners and transitions, include full dimensional and metallurgical inspections for all components (Fig A2).

Downstream deflection correction, radial and axial packing seal replacement, airfoil thickness verification, multiple-segment fixturing for accurate shop assembly, and area and harmonics analyses for all stages are part of the nozzle overhaul experience. Chemical and mechanical coating removal, eddy-current verification of cooling-hole wall thickness, "Z"-notch restoration, and OEM-equivalent coatings highlight the company's bucket restoration effort.

Small engines. Of particular interest to GT users at commercial, institutional, and small industrial plants is that Phoenix Turbine repairs and refurbishes parts of Ruston TB500 and TB5400 engines, Siemens' Tornados and Typhoons, and Solar Centaurs.

Located only 20 miles from Sky Harbor International Airport, the company is able to cherry-pick services from local shops working primarily in aviation to further expand its repair offerings. Like Harrison says, "Phoenix is a GT town." CCJ

A1. Standing inventory of 501AA diaphragms, DF42 baskets for Westinghouse engines, and 501B fuel nozzles (left to right)

A2. Phoenix Turbine's new combustion repair and manufacturing cell (right)

P&W invests millions in San Antonio, Singapore shops

Returning to Pratt & Whitney Power Systems' San Antonio shop after an absence of nearly three years was like taking a ride in a time machine. There had been dramatic improvements—including significant additions in floor space, equipment, personnel, and advanced NDE (nondestructive examination) tools.

At the end of 2007, when the editors last visited, PWPS shared the repair shop with a military engine overhaul group. The latter was relocated early in 2008, allowing expansion of the commercial business. At the same time, United Technologies Corp initiated action to bring San Antonio up to what Pratt & Whitney's parent refers to as its ACE standards. Achieving Competitive Excellence is an internal quality program similar to Six Sigma.

Over the next two years the shop was transformed into a bright, modern repair facility with the latest inspection and repair tools, efficient production lines, and additional personnel qualified to operate and maintain the new equipment and tooling (Fig B1). Today the facility is a one-stop shop—strip to ship—for inspection, refurbishment, and repair of F-class HGP parts. It's easy to draw similarities between San Antonio and Pratt's world-class aircraft-engine assembly plants in the Hartford area. PWPS has accumulated more than 1-million factored fired hours on its F-class new-part products.

The editors met with key personnel in the conference room for a backgrounder before spending a productive couple of hours on the shop floor. General Manager Gerald D Hill, Engineering Manager Jose M Quinones, PE, and Program Manager Jollin D'Souza stressed the company's ability to perform all operations required to refurbish F-class HGP components for another operating cycle—except acid stripping of coatings. That is outsourced to a firm in Houston for environmental, health, and safety reasons.

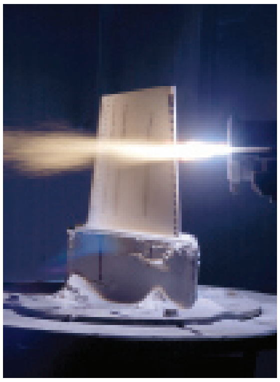
In addition to restoration repairs, PWPS pursues design improvements with the goal of providing refurbished parts that are "better than the original" where possible. The collaborative process of continual component improvement involves (1) identification of issues based on field experience, (2) re-engineering and modeling of improved parts at the company's East Hartford offices, (3) laboratory validation, and finally (4) field validation.

The successful San Antonio experience now is being transplanted in Asia. In the last 18 months or so, the trio of experts said, market demand for quality repairs has grown dramatically in that region. So the com-

All photos by Rick Koehler

B1. Vane repair line extends from one side of the shop to the other

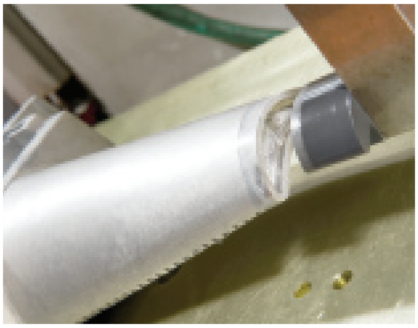
B2. Fred Miller loads one of the facility's new vacuum furnaces

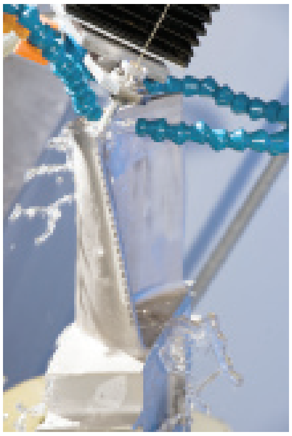


B3. Plasma spray (left) is applied to the first-stage blade for a V94.3A2 engine

B4. EDM machines (below) are operated by Orlando Cantu (left) and Alex Escobedo

B5. Graphite-plunge EDM operating on a 7FA first-stage bucket



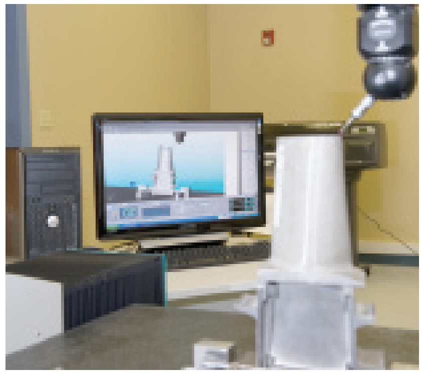


B6. Drilling cooling holes in 7FA first-stage bucket with EDM electrode (left)

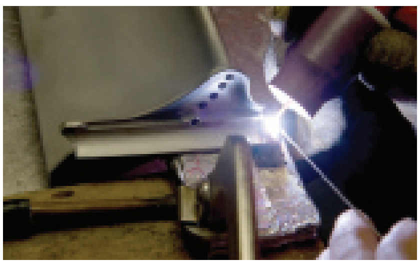
B7. Spraying dye penetrant on 7FA combustor parts (above)

B8. Ultrasonic inspection of 7FA second-stage bucket performed by Sean Mathues (left)

B9. Dimensional check of 7FA first-stage bucket (right)



B10. Tip welding of 7FA+e first-stage bucket



B11. Welding of Z notch on 7FA second-stage bucket

B12. Blending of 7FA second-stage bucket

pany has applied its San Antonio model and leveraged the capabilities of its existing aero shop in Singapore to serve industrial gas turbine customers there.

The dominant machine in that region is E-class (GE models 6B, 9E, 7E, and 7EA, plus Siemens 501D5/D5A and Alstom 11N) at the moment and the shop equipment and processes are arranged to meet that need. Note that the plant also does work for US and European customers—including welding, brazing, coatings, and acid-stripping—on a time-available basis.

Plans are on the drawing board to ramp up Singapore's technology and skill sets to handle F-class machines as well. This will happen sooner rather than later given GT additions in Asia. First step will be to install the capability to handle stationary hardware, then rotating.

The shop tour focused on some of the latest equipment installed to assure world-class repairs. Highlights:

- Two vacuum heat-treat furnaces were added to complement existing capability. Each of the new furnaces can process an entire row of F-class buckets at once (Fig B2).
- Five thermal spray booths, all equipped for air plasma spray (Fig B3), two also for HVOF (high-velocity oxygen fuel).
- CNC (computer numerical control) shot-peening machine to prestress blade roots.
- EDM (electrical discharge machine) tools (Fig B4)—one a sinker tool to precisely shape the blade tip (Fig B5) and two for drilling cooling holes (Fig B6).
- Ultra-dense coating booth. This is PWPS's version of TBC (thermal barrier coat) which is conducive to a high-quality surface finish. Its preinduced cracks allow fast startup and shutdown without spalling.

Today's NDE tools are especially impressive (Figs B7-B9). Examples:

- Two coordinated measuring machines were installed to do incoming, in-process, and final inspections. They are fast, efficient, and get parts to the door quickly. All benchmark information for parts is provided electronically and retained. Engineers trend and analyze data collected during incoming inspections to optimize repair processes.
- High-power (450 kV) digital x-ray to check thick sections very quickly. Digital records allow comparisons over time.
- Frequency scanning eddy current (F-Sect) for thickness and beta-phase depletion measurement of protective coatings on airfoils. Previously multiple samples were required to get statistically valid bond-coat and top-coat thicknesses. With F-Set, it's only necessary to destructively test one airfoil to verify the instrument's setting

and the accuracy of the data collected.

- A full metallurgical lab has been installed, thereby enabling analysis of microstructure, coatings, etc, right on the shop floor.

Experience base. As of January 1, PWPS had repaired 370 sets of F-class hardware, including 59 sets from V84.3 and V94.3 engines (Figs B10-B12). The lead set of the 50 sets of first-stage buckets repaired thus far has operated for 72,000 hours; the lead set of the 28 sets of first-stage nozzles repaired is at 48,000 hours.

New hardware. In addition to repairs and field service, PWPS offers an expanding list of new HGP parts for frame machines. The company says these parts reflect its extensive experience in the design of high-temperature on-wing engines. The use of advanced materials, cooling schemes, and coatings extend component lifetimes and reduce life-cycle costs. Components come with repairability guarantees. Here's a short menu of parts for popular engines operated by North American power producers:

- 6B first-stage 12-hole bucket featuring P&W's proprietary directionally solidified (DS) base alloy, internal aluminide coating, external low-pressure plasma spray (LPPS) metallic coating.
- 7B-EA first-stage bucket is made of an equiaxed nickel-base superalloy for long life. High-temperature (up to 2055F) performance is achieved with LPPS and TBC coatings. PWPS says its bucket design helps prevent platform cracking without increasing the flow of cooling air, which adversely impacts engine performance.
- 7FA+e buckets, nozzles, and combustion parts. First-stage buckets are manufactured using a proprietary DS alloy and TBC, and enhanced cooling scheme, for improved creep and oxidation life. Features built into first-, second- and third-stage buckets assure 72,000 hours/2700 starts—possibly longer depending on the results of a technical evaluation at 72k. Parts performance is backed by repairability guarantees.

Combustion liners, flow sleeves, and transition pieces incorporate alloys and coating systems for superior creep, oxidation, and wear performance aimed at extending parts life beyond the industry average and reducing life-cycle costs. CCJ

Allied dedicates new repair shop, targets F-class market

Meteorotic certainly describes Allied Power Group LLC's business growth since the company's founding 10 years ago. The dedication of its impressive 75,000 ft^2 repair shop in Houston last May testifies to that. The new shop, which sits on 14 acres, is quadruple the size of the previous facility and centralizes company headquarters, sales, repairs, and warehousing in one location.

Recall that Allied is a holding company which combined the assets of PowerSpares and Turbine Blade Repair Specialist (TBRS). It was formed to offer gas-turbine owners and operators a single source for high-caliber turbine replacement parts and fast, expert repairs of hot-gas-path (HGP) components.

When the companies came together, PowerSpares had one of the world's largest inventories of GE Frame 5, 6, 7, and 9 parts and TBRS was well known for its capabilities in the inspection, refurbishment, and repair of HGP and combustion-system components.

Current capabilities include an engineering team to determine the best method of repair, grit blasting, a complete NDE (nondestructive examination) line, heat treatment and coatings, welding and machining areas, a clean room for CMM (coordinate measuring machine) and flow testing, and a customer inspection area.

"The new facility allows Allied to control all of its repair operations under one roof—which, in turn, will reduce customer turn times. One of the core values for Allied Power Group," Engineering Manager Alan Lovelace, PE, told the hundreds on hand for the dedication and open house in early May, "is customer responsiveness and the new facility will enhance this key attribute even more."

Don't pass on the opportunity to visit Allied Power Group's new shop next time you get to Houston. Call ahead and make arrangements through CEO Bruce Agardy, Executive VP Mike Elliott, President Keith Marler, or COO Louis Green (l to r on the bed of the VBM shown in Fig C10)

President Keith Marler added, "We are very excited to have made this next step in the evolution of our business. All of this growth is in response to our customers' needs, our employees' dedication, and our team effort that we bring to the table."

The additional tooling and streamlined work-flow processes made possible by the new facility have increased efficiency and enabled a 50% increase in throughput with capacity to spare. Roughly three-quarters of the company's business is in refurbishment and repair of F-class components, where Allied believes it has advantages both in experience and business flexibility.

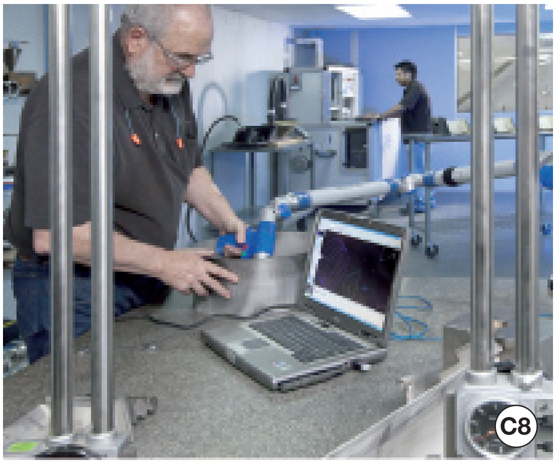
Regarding the latter, the company remains privately owned, allowing customized repair solutions and financial arrangements. For example, it has pioneered repairs for some W501F components, including ring segments. Declared scrap by the OEM, Allied engineers and technicians told the editors how they developed a fix for about one-third the cost of new parts and have successfully repaired several condemned sets.

The company also has developed a machining process and the fixturing necessary to machine the side gaps on 501F vanes to close tolerance.

Curriculum vitae

Technical Director Aaron Frost offered an overview of Allied's deep experience in the repair and refurbishment of F-class parts at the 7F Users Group meeting a week after the open house. One example: The company claims the largest repair experience base on DLN2.6 components—caps, liners, and transition pieces (TPs)—outside the OEM.

It had repaired more than 50 sets



Tour Allied Power's new shop

C1. Machining area. CNC (computer numerical control) and manual equipment is in full view as you look down the aisle. Note the high-tech turning center from Haas Automation Ltd at the lower left

C2. Nozzle and vane area. Completed nozzle row is lifted from table while assembly of a 7EA second-stage nozzle row is just getting underway

C3. Compressor diaphragm assembly area

C4. Welding and customer inspection area. Proper fit-up of turbine buckets is confirmed in foreground; at right, 7FA+e combustor covers and liners are set out for inspection after coating. The welding area has 25 booths

C5. Visual inspection of parts prior to fluorescent penetrant inspection

C6. Dimensional check of 7FA+e flow sleeves

C7. 501F R2 vane ring was preassembled for dimensional inspection

C8. Repaired combustion liner is inspected using a sophisticated coordinate measuring machine from FARO Technologies Inc—typically called a FARO arm. Flow testing is in the background

C9. Repairs are made to the aft end of a 7FA+e combustor liner

C10. 501F compressor case is prepped for machining on a 130-in. (maximum swing) vertical boring mill

C11. Final dimensional inspection of repaired 7EA third-stage buckets is conducted after airfoils are installed in turbine disc

C12. Special fixturing is used for checkout of 7FA+e second-stage nozzles

of combustion caps and made more than 420 individual effusion-plate replacements; repaired more than 60 sets of combustion liners, including more than 80 aft-end replacements; and repaired more than 40 sets of TPs. Some of the combustion liners and TPs were in the shop for the third repair, having more than 36,000 hours of service and 1800 starts.

Scorecard of 7FA+e HGP component repairs: Over 100 sets of HGP components—including buckets, nozzles, and shroud blocks. For the 7EA: Over 230 sets of HGP components (including buckets, nozzles, and shroud blocks); plus, 94 sets of combustion liners, 93 sets of TPs, 12 sets of flow sleeves, 58 sets of bullhorn brackets, and 34 sets of crossfire tubes.

Scorecard of W501F HGP component repairs: Over 200 sets of HGP components—including blades, vanes, and ring segments. In addition, more than 100 rows of compressor diaphragms have been repaired along with blade rings for seven compressors and four turbines.

Shop tour

For now a shop tour in print will have to suffice. To see more, contact Lovelace, Marler, Frost, Marketing Manager Kelly Moore, CEO Bruce Agardy, Executive VP Mike Elliott, or COO Louis Green—you're sure to know one or more them—and arrange for visit next time you get to Houston.

The first four pictures in the sequence are overviews of the specialized work and inspection areas, the next four are of inspection processes, Figs C9 and C10 show repair work, and C11 and C12, the all-important fixturing to assure proper fit-up during reassembly at the plant. CCJ

Comments

Clarification. I wanted to alert readers to an inaccurate statement pertaining to the ease of installation of the Cutsforth EASYchange brush holder. In Clyde Maughan's article, "Maintaining carbon-brush holders" (COMBINED CYCLE Journal, 1Q/2010), the following statement on p 104 is inaccurate and misleading: "The Cutsforth Inc holder requires a change-out of the buss rings to implement."

In actuality, 95% of Cutsforth's EASYchange brush-holder retrofits are simple, bolt-on conversions requiring no change-out of the buss rings. EASYchange is, in fact, a simple and direct drop-in replacement to existing OEM holders. More detail is available at www.cutsforth.com.

Steve Thompson
Marketing and Sales Director
Cutsforth Inc

Bucket-rock wear. One topic included in your 3Q/2009 report on the 7F User Group meeting related to bucket-rock wear (3Q/2009, p 24, middle of center column) requires clarification. The passage identified suggests reducing rpm as a means for reducing bucket-rock wear, but then offers a dissenting opinion, which is incorrect because the units are on lift oil.

Koenig Engineering recently announced a low-speed rotation option for its turning gears that solves the bucket-rock wear dilemma; however, the comment in your article leads the reader to believe our option may not be the best solution. Readers wanting to learn more about the Koenig solution can contact me at brent.erickson@koenigengr.com.

Brent Erickson
Sales Engineer/Marketing Manager
Koenig Engineering Inc

Association news

CAREBS. Several major energy development firms—among them Dresser-Rand Inc, Haddington Ventures LLC, Texas CAES, Iowa Stored Energy Park, and HDR/DTR Engineering—have formed the Coalition to Advance Renewable Energy through Bulk Storage (CAREBS). Group's primary focus is to educate and advocate for bulk energy storage.

"Bulk energy storage technologies are critical components in America's energy future," says Executive Director (acting) Jason Makansi. "As more wind and solar come online, grid operators and dispatchers will increasingly rely on bulk storage technologies to minimize intermittency problems, assist in moving renewable energy long distances, and reduce the wear and tear when power stations are cycled.

For more information, visit www.carebs.org.

Mark Yarbrough, 1961-2010

The editors join family, friends, and the industry in mourning the passing of Mark Edward Yarbrough, an Arkansas country boy with a lust for life, an engaging personality, and an infectious smile. He was a top-notch powerplant chemist with a positive attitude and a passion for problem-solving.

We first met Mark about five years ago at Redhawk Generating Station (Arizona Public Service Co) just west of Phoenix, looking to come up to speed on ZLD technology (zero liquid discharge). Plant Manager Scott Takinen, Mark's mentor on things combined cycle, told us this was the person we had to talk to.

We left Redhawk a few hours later thoroughly intimidated and wondering if we would ever be able to understand ZLD chemistry. Mark never gave up on us and was always available to answer any and all questions—even from home. To ensure that we would continue to grow in the field water chemistry to better serve the industry, he got us involved in the Southwest Chemistry Workshop, which has been a rewarding educational experience.

Mark was on the cutting edge of water technology and known globally for his research, development, and implementation of processes for waste water reuse and cooling-water disinfection for powerplant applications. Last year the methodology and system he developed for reducing organic contaminants in feedwater was patented.

Plant news

State Line Combined Cycle, a recipient of the 2010 Best Practices Award for Safety, had its staff photo misplaced during layout of the Best Practices article (p 112). The editors apologize. Photo is included here.

Goodsprings Waste Heat Recovery Plant, NV Energy's first non-solar green-energy project and the first facility of its type in the state, now under construction, will produce 6 MW with exhaust heat recovered by an organic Rankine cycle from a compression station owned by Kern River Gas Transmission Co.

People/appointments

MidAmerican Energy Co, Council Bluffs, Iowa, appoints Dave Ulozas VP generation. Ulozas, a former chairman of the 7EA Users Group, has responsibility for four coal-fired generating stations and a collection of Frame 5s, 6s, and 7s along with a W501FD2-powered combined cycle.

State Line Combined Cycle staff shows off its 2010 Best Practices Award for Safety. Front row (l to r): Bill McNeil, John Woods, Scott Boatright, Terry Krause, and Jason Osiek. Back row: Kenny Stratton, Bill Howell, Ed Easson, Steve Cornell, Robert Elbert, Ken Case, and Stuart Houston

THE CLASSIFIEDS

Equipment • Employment

Johnson Matthey plc, Stationary Emissions Control Business Unit, Malvern, Pa, names Michael Baran eastern sales manager for gas-turbine catalyst and systems business; Robert Bono western sales manager for process and engine catalyst and systems business; and Jeffrey Sherman business manager for industrial processes and engines.

Brush Americas, Houston, appoints Andrew Gillott VP aftermarket. The company is rapidly expanding its generator life-cycle support operations with parts, tooling, and personnel to support the more than 1200 Brush machines operating in the Western Hemisphere.

TDC Filter Manufacturing Inc, Bolingbrook, Ill, welcomes Patty Gulsvig (formerly The Donaldson Company) to its gas-turbine sales team. Gulsvig, who has more than 25 years of experience in filtration solutions selling, is well known among owner/operators from her participation in user-group activities.

Vogt Power International Inc, Louisville, promotes Tony Thompson to chief technology officer. Joe Nitzken joins the company of VP engineering, replacing Thompson.

NAES Corp, Issaquah, Wash, names John P Brewster president and CEO. Brewster's background includes 32 years of experience in powerplant operations, maintenance, and executive management with companies such as NRG Energy and Cajun Electric Power Cooperative Inc.

Products/services update

ESCO Tool, Holliston, Mass, announces a portable welding end-prep tool that performs multi-angle end preps and squares-off heavy-wall stainless steel and other hard alloys without work hardening. It is suitable for pipe and tube from 1.5 in. ID to 6.625 in. OD.

Millhog® tube expanders and rolling motors for creating tight steel-to-steel mechanical seals in boilers, heat exchangers, and condensers are air-powered and feature precise torque control from 25 to 325 ft-lb. Five kits accommodate tubes from 1 in. ID to 4.25 in. OD with wall thicknesses from 1 to 20 gauge.

Pneumatic saw (requires 90-psig air) and quick-clamp assembly allows user to cut steel plate up to 2 in. thick and 15 ft wide. Saw mounts on a bracket that glides along the track using four V-groove steel wheels. Perfect square cuts are reported.

Swift Filters Inc, Oakwood Village, Ohio, announces a new series of filter elements. Media made of thin filaments of non-woven stainless steel is designed for high-pressure, corrosive,

DRB president elected to Oklahoma State House

David Brumbaugh, president and owner of DRB Industries LLC, Broken Arrow, Okla, was elected July 27, by an 80% margin, to represent District 76 in the Oklahoma State House of Representatives. He is a familiar face at gas-turbine user group meetings, both as a presenter on inlet-air filter and cooling technologies and as an exhibitor at vendor fairs.

Brumbaugh is a well-known civic leader in the Tulsa area, serving as library commissioner, church and school board member, and as a member of several Chamber of Commerce committees. He is an army veteran (101st Airborne Div) and has multiple degrees, including an MBA.

or viscous applications. This so-called metal felt is highly porous and allows flow rates of up to 20 times those of alternative media types. More information is available at www.swiftfilters.com.

SwiftGreen™ filter elements have a reusable machined aluminum bypass valve assembly that reduces filter costs by 35-40% compared to traditional (non-recyclable) return-line elements. The filters are designed as direct replacements for most major OEM filter elements used on the return side of a hydraulic/lubrication circuit.

Ludeca Inc, Doral, Fla, announces Vibxpert® II, the latest addition to the company's family of portable route-based vibration data collectors. The instrument features an easy-to-use icon-driven platform conducive to rapidly solving complex vibration problems. Details are at www.ludeca.com/vibxpert.

Rotalign Ultra Live Trend, a short-term continuous monitoring application, helps to accurately determine the relative positional changes between coupled machines during run-up or shutdown. It uses a five-axis sensor to monitor, in real-time and simultaneously both the vertical and horizontal parallel and angular displacement of a rotating machine. Details at www.ludeca.com/prod_rotalignultra-machine-positional-change.php.

Laser Align is a free reference tool for aligning the shafts of rotating machines. With this app you can access important reference material and learn about key laser shaft-alignment concepts. Download the iPhone app at http://itunes.apple.com/us/app/laser-align/id371520051?mt=8.

Olympus NDT, Waltham, Mass, announces a semi-automated ultrasound phased-array solution for corrosion mapping applications. The HydroFORM solution enhances inspection quality, operator safety, and mechanical dependability in the NDE of metal plates, pipe, and welded components. It detects internal corrosion, mid-wall anomalies, and environmental damage. Visit www.olympus-ims.com/en/scanners/hydroform.

Company also introduces long scopes (32.8 ft) for its Iplex LX and LT videoscopes to extend the instruments' reach into difficult-to-access areas. A wide range of interchangeable optical adaptors enables top-quality magnification, direction, and illumination.

Parker Hannifin Filtration & Separation Div, Haverhill, Mass, allows plants to make consistently pure (99.9%) nitrogen from compressed air for use in boiler layup and other activities. The Parker Balston nitrogen generator in is said to help prevent general corrosion, corrosion fatigue, and stress corrosion cracking in HRSGs, steam systems, and turbines at lower cost than cylinder-supplied gas.

The company's Instrumentation Products Div introduces three captured O-ring feed-through and bulkhead fitting products for use in process analyzer sampling and electronics enclosures. Details on these fittings are at www.parker.com.

E H Wachs Co, Lincolnshire, Ill, introduces the EP 424 with Speed-Prep Auto-feed. The ID-mounted end-prep machine tool is designed to bevel, compound bevel, J prep, face, and counterbore pipe, fittings, and valves. It is powerful enough to form tool from 4 to 16 in. through Schedule 160, and single point from 4 to 24 in. up to 6.5-in. wall.

W L Gore & Associates Inc, Elkton, Md, introduces an air inlet filter for gas turbines that provides high-efficiency, submicron filtration and prevents virtually all dirt, salts, and other contaminants from entering the unit. Result is minimum compressor wear and more consistent power generation.

Emerson Process Management, Pittsburgh, releases the latest version of its Ovation™ expert control system, which features an improved operator interface, field-device configuration/troubleshooting environment, and graphics building tools. The enhancements translate into greater operator efficiency and productivity, and minimize the risk of human error. More information at www.emersonprocess-powerwater.com.

Company news

Turbine Maintenance & Plant Services LLC, a Texas-based consultancy, is formed by William Stacey Davis, former plant manager for maintenance and outages at Guadalupe Power Partners, to provide maintenance planning, scheduling, preparedness, and supervision for the electric power industry. Davis is known for insightful, crisp presentations at user group meetings (wdavis34@satx.rr.com). This year he was on the podium at the 7F and Frame 6 User Group meetings.

Clark-Reliance Corp, Strongsville, Ohio, a world leader in boiler level and control, acquires Oil Filtration Systems Inc, Boerne, Tex, a manufacturer of systems for removing particulates, water, gasses, and acids from oils and fuels.

Turbine Generator Maintenance Inc (TGM), Cape Coral, Fla, an independent provider of inspection, maintenance, and repair services for owner/operators of steam and gas turbines, has been taken private by its senior management team. David Branton, Robert Davis, and Tod Feeley recently purchased the company from GFI Energy Ventures LLC.

Branton is well known in the industry, having held senior executive positions at both Westinghouse Electric Corp and Wood Group; Davis is the CFO and Feeley, who has been with TGM for 17 years, is VP sales and marketing.

The company recently hired Mark Sherrill, formerly rotating equipment supervisor at GWF Power Systems, as technical director. Sherrill has more than two decades of experience in the maintenance of solid-fuel-fired generating plants with a wide range of steam turbines by manufacturer and size. He assumed responsibility for gas turbine maintenance as well shortly after the millennium, developing core expertise in LM6000s and 7EAs. He was active in both the Western Turbine Users Inc and 7EA User Group before leaving GWF.

HRST Inc, Eden Prairie, Minn, expands its services to include rapid-response technical assistance for a variety of boiler-related activities. For example, the technical advisor (TA) will assure that all demolition, modifications, repairs, welding, and quality control are performed to the highest technical and boiler code requirements.

Johnson Matthey plc's Stationary Emissions Control Business Unit, Malvern, Pa, is awarded ISO 9001: 2008 status, certifying that its quality management system is in conformance with the latest worldwide standards.

Gas Turbine Efficiency plc, Orlando, reports an uptick in orders from the energy industry for its compressor water wash system. Four of the major gas-turbine OEMs have approved use of the GTE washing solution on their engines.

Prueftechnik Alignment Systems, Ismaning, Germany—Ludeca Inc's principal—opens a high-tech lab at the company's headquarters location to strengthen its technological prominence and abilities in measurement technology.

BASF Catalysts, Iselin, NJ, announces that 200 of its Camet® CO oxidation catalyst systems have now been serving power generation facilities for more than 10 years.

KE-Burgmann USA Inc announces the acquisition of Expansion Joint Systems, Santee, Calif. The parent company is a leading manufacturer of metal hoses and fabric, metal, and rubber expansion joints. EJS's new name is KE-Burgmann EJS.

Emerson Process Management, Pittsburgh, acquires epro GmbH, Gronau, Germany to expand the parent's online machinery monitoring capability with a full API 670-compliant protection offering. The acquisition also is expected to speed the availability of next-generation solutions.

COMBINED CYCLE Journal

2Q/2010

Index to advertisers

Moran Iron Works Inc Onaway, Mich, adds a CNC controlled plasma precision cutting table to speed production. The new machine can handle sheet 20 ft × 8 ft and cut thicknesses up to 2 in. Also added: A CNC beam coping machine capable of cutting any type of beam, channel, and angle, as well as plate and rectangular tubes, at speeds up to 30 in./min.

ProEnergy Services, Sedalia, Mo, an integrated service provider to the global power industry, adds a new division to provide turbine repair services—such as rotor repair and balancing, component refurbishment, unit overhauls, state-of-the-art welding, nondestructive examination, high-temperature costings—for a wide range of GT models.

Stellar, Jacksonville, celebrates its 25th anniversary. The integrated construction, design, engineering, and mechanical services firm is best known to readers of this magazine for its inlet chilling systems for gas turbines.

NAES Corp, Issaquah, Wash, celebrates its 30th anniversary. Founded in 1980 by four Northwest utilities as a captive project management organization, the company has steadily expanded its service offerings. Today it is thought the world's leading provider of third-party O&M services. NAES also provides major maintenance, shop mechanical repairs, special technical support and consulting services, and generator inspection and repair services.

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