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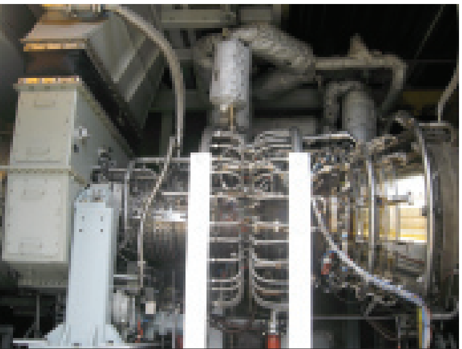

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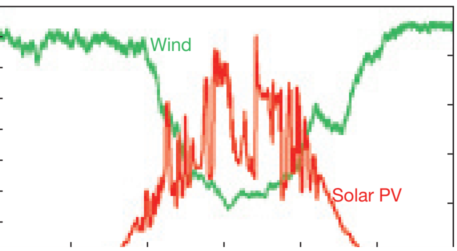

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INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

Toledo emerges as an industry leader with state-of-the-art cogen plant to power critical facilities

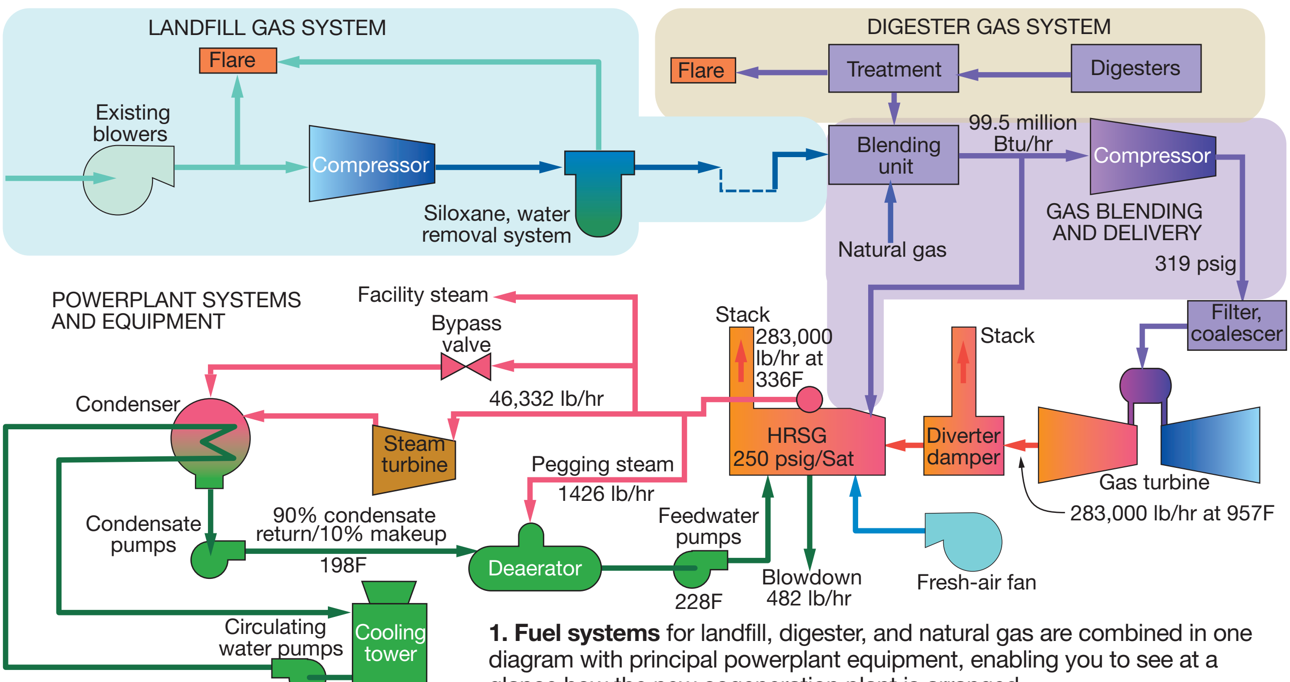
The Bay View Combined Cycle Cogeneration Facility is a project surely to be appreciated by power-generation professionals (Fig 1). It has the ability to burn both conventional and "green" fuels separately or simultaneously in both its gas turbine and heat-recovery steam generator (HRSG). Also, and perhaps more importantly, the facility is designed for maximum operational flexibility to provide the City of Toledo's Div of Water Reclamation (DWR) the level of reliability it needs to assure continuity of operations at the critical Bay View Wastewater Treatment Plant (Sidebar 1).

Most people do not think of sewage treatment plants as "critical" facilities, nor do they associate them with the need for a highly reliable supply of electric power. But environmental rules impacting wastewater-treatment operations have become more demanding in recent years, as they have for powerplants. When you're handling 2.5 million gal/hr of liquid waste on average, even a brief outage can seriously upset flows and water chemistry—and possibly lead to fines.

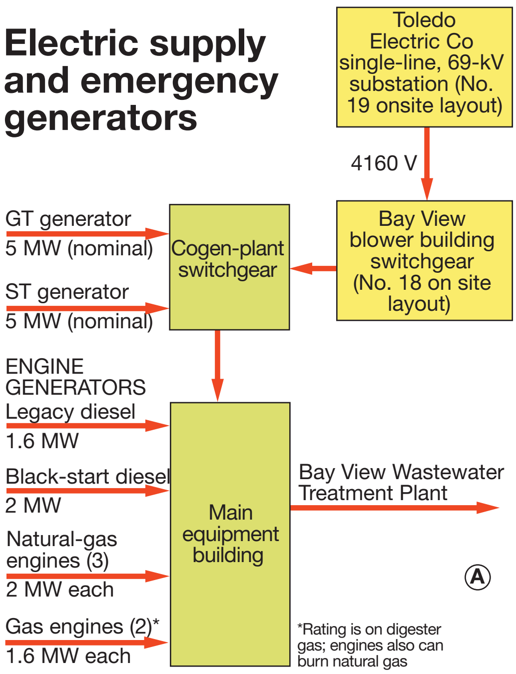
Continual improvement of water treatment processes is engrained in Bay View's culture. A quick read of the sidebar on the facility's history is proof of that. However, it wasn't until after the millennium that serious attention was focused on the single 69-kV line supplying Bay View's electricity through a 10-MW 69/12/4.16-kV substation. There was no alternative source of power. Reliability engineers viewed this as a serious weakness; so did the EPA.

In 2004, a backup generating facility was incorporated into the mechanical equipment building (No. 17 in the aerial photo accompanying Sidebar 2, which explains how Bay View works). Three 33,350-cfm motor-driven centrifugal blowers were installed as well, to replace the engine-driven blowers that had been providing air to the aeration tanks (Fig 2). Six Caterpillar engines with a combined capability of up to 12 MW were added to the existing 1.6-MW diesel/generator shown in Fig 2C. One of the six is a black-start unit, three are powered by natural gas, two can burn green gas or natural gas.

Motivation for installing a 10-MW, Taurus™ 60-powered 1 × 1 combined cycle capable of burning gas collected from the city's Hoffman Road Landfill, as well as gas produced by the wastewater-treatment plant's digesters, included the following: (1)



1. Fuel systems for landfill, digester, and natural gas are combined in one diagram with principal powerplant equipment, enabling you to see at a glance how the new cogeneration plant is arranged



2. The new cogen plant is integrated into an especially flexible and reliable electrical supply system that includes a 69-kV line from Toledo Edison Co and seven engine generators with multiple fuels capabilities **(A)**. Three aeration blowers **(B)** for wastewater treatment share building numbered 17 on site layout with the engine generators **(C)**

reduced emissions from city operations (improved local air quality), (2) reliability benefits of onsite generation, and (3) lower cost of electricity. The cogen plant began commercial operation in fall 2010.


Schreidah

The city's project manager for both the engine-based backup generating facility and the combined cycle was Michael Schreidah, PE, a 22-yr veteran with the Dept of Public Utilities (DPU) within the DWR. Engineer on the cogen project was Middough Inc, Cleveland; constructor was Barton Malow Co, Southfield, Mich. Middough's primary interface with the city on the combined cycle was Martin F Ellman, PE, senior manager for energy technology. He talked to the editors about the project's special requirements/challenges. Among them:

- Design the plant for base-load operation on landfill and digester gases; initial thinking was that natural gas would be an emergency fuel. However, at the rate of green gas production today, the cogen plant is limited to about 3.5 MW on landfill and digester gases. Natural gas must be added to the fuel mix to produce more power.
- Provide the flexibility to run the combined cycle at about half load most of the time, but have the ability to produce up to 10 MW during periods of abnormally high wastewater flows. Ellman said 4.5 MW or less is required to operate the treatment facility most days.
- Arrange the combined cycle to operate in parallel with the grid and the engine generators.

Project organization. The Bay View cogen project had three major elements of interest to engineers:

- Gas treatment and blending systems and equipment (Solar Turbines).
- Combined cycle and balance-of-plant systems (Solar Turbines).
- Landfill gas pipeline, 5-kV feeder to supply power to gas treatment equipment at the landfill, natural-gas pipeline extension, and fiberoptic link between the cogen plant and landfill (InfraSource, a Quanta Services company, Glen Ellyn, Ill).

Landfill gas system

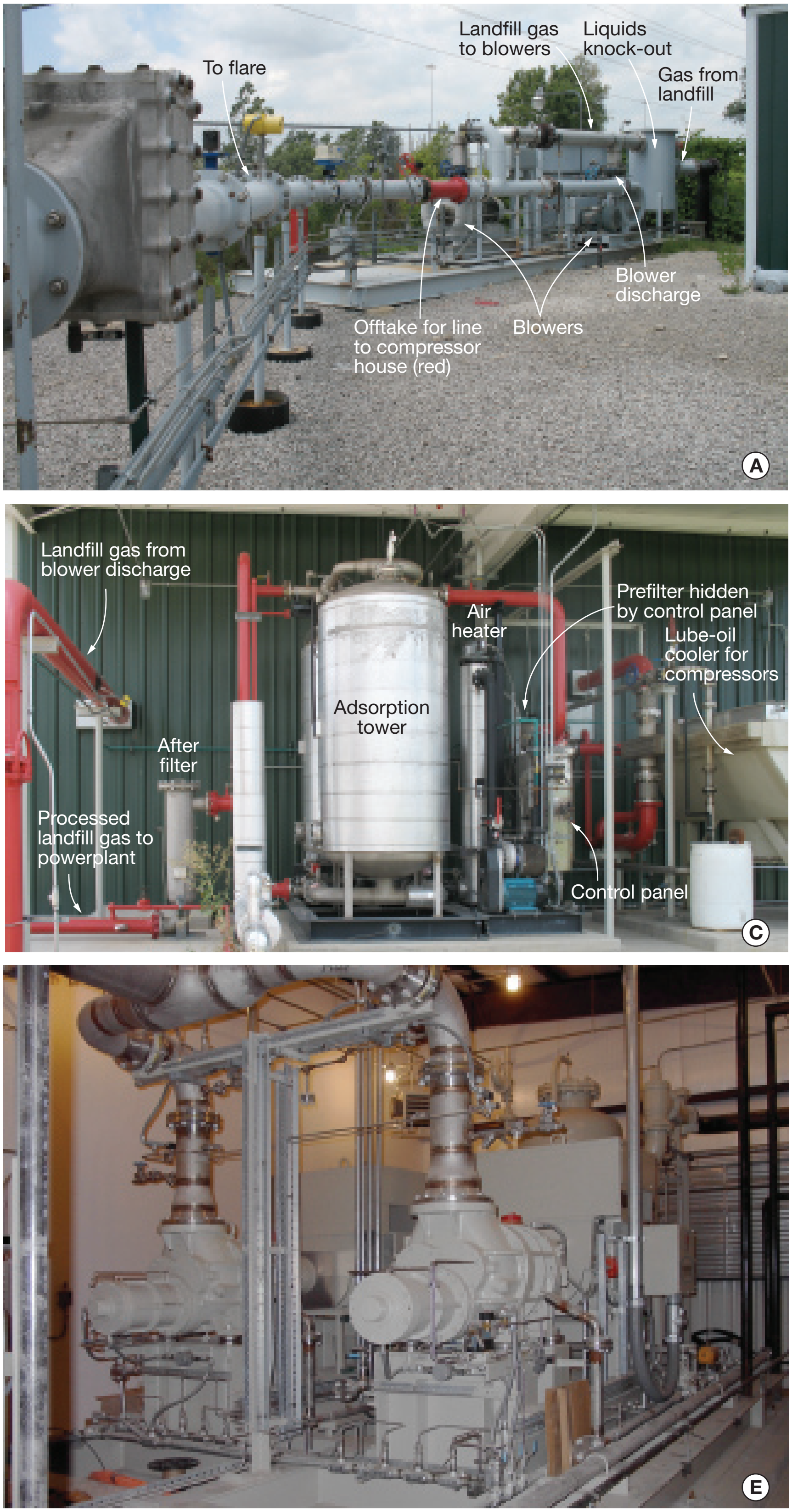
The Hoffman Road Landfill, located about two miles from the cogen plant (No. 3 in the aerial photo), began operating in 1974, well before the power project was conceived. It is expected to remain in service for 15 to 20 more years and produce enough gas to support power-generation activities for at least another 25 to 30 years.

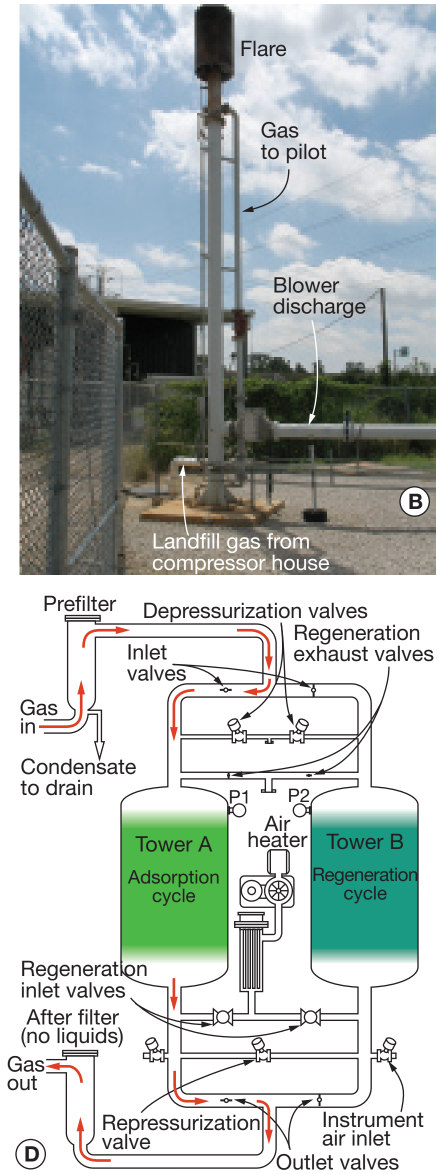
Schreidah said that during the design phase of the combined cycle, the city expected the landfill to provide 1500 scfm of gas with a heating value of between 500 and 550 Btu/scf.

But the downturn in the economy has had a negative impact on gas production, now at about 1150 scfm. Methane typically comprises 45%-55% of landfill gas, with most of the remainder CO_2 (45%-50%). Hydrogen is the next most common constituent at 1%-5%.

Before the combined cycle was built, gas was flared (Fig 3). Toledo's Dept of Public Service, which operates and maintains the landfill, had been trying to sell the gas for years but was unsuccessful until the idea of building a cogen plant gained support. Although DPU, the combined-cycle "owner," is a sister agency to DPS, a fuel-supply contract is in place and DPU "pays" DPS for the fuel.

The basic flare system in Fig 3A





3. Landfill gas system infrastructure is located adjacent to the waste repository. Blowers pull the gas in from the collection grid **(A)** and deliver it to the compressor house via the red pipe or to the flare **(B)**. The latter is equipped with a landfill-gas pilot to assure positive ignition of the waste gas when needed. The siloxane and moisture removal system **(C, D)** resides just outside the compressor house. Compressors **(E)** boost landfill gas to a nominal 45 psig before it goes to the filters and adsorption column. After cleanup, the gas flows through a 1.9-mile, 10-in.-diam high-density polyethylene pipe to the powerplant

existed before the cogen plant, but it was upgraded as part of that project. The red spool piece in the middle of the photo, a tee, was added to direct landfill gas, previously flared, to the adjacent compressor building and treatment system where the green gas is cleaned-up before being piped to Bay View. Project engineer for this work was Mike Kemp of HCS Group Inc, Houston, a subcontractor to Solar Turbines.

In addition, a small line was run from the discharge side of the landfill-gas compressors to the flare. The green gas it delivers supports the flare's pilot flame (Fig 3B). Note that the flare is a critical component because it destroys gas that otherwise might be released to atmosphere in the event of a system upset. Release of landfill gas to the natural environment is not permitted by law. Operation of the landfill-gas collec-

1. Bay View's history in brief

Bay View, the largest wastewater treatment facility in Northwest Ohio, is located in Toledo near the mouth of the Maumee River. It has a service territory of about 100 mi^2 and receives water from industrial, domestic, and commercial sources.

Federal, state, and local regulations governing the operation of, and discharge requirements for, wastewater treatment plants have evolved over the years just as they have for powerplants. Toledo's first wastewater collection facilities were constructed in Bay View Park in 1922 on the site of the world's first heavyweight championship fight between Jess Willard and Jack Dempsey (the winner) held three years earlier.

Primary treatment ordered by the Ohio Dept of Health began in mid 1932 and by the late 1930s primary settling tanks, a sludge digestion system, and chlorination facilities had been added. Secondary treatment using the activated sludge process commenced in 1959, with large diesel engines driving the air blowers required.

In the mid 1960s a new sludge dewatering facility and filter building were constructed and in 1969 the primary and secondary systems were renovated and expanded. That work was followed by enhancements to, and expansion of, the wastewater collection system in the 1970s. In the 1980s, tens of millions were spent to renovate, upgrade, and expand all processes and equipment at Bay View to meet more stringent regulatory requirements.

The 1990s brought still more improvements—including a new sludge stabilization facility, upgrades to electrical systems and controls, new final clarifier, enhancements to oil and grease skimmers and grit collection, etc. Between 2005 and 2007, $90 million was invested in a "wet weather" treatment process which included the largest ballasted flocculation system in the nation and a 25-million-gal equalization basin.

Obvious from the foregoing is that Bay View embraces a culture of continuous process improvement to assure world-class reliability and efficiency of the 24/7 facility. The same culture is embraced by staff responsible for site's energy systems, which enable the massive plant's operation.

tion system and flare are monitored from the cogen plant.

There are two fundamental steps in landfill-gas processing at Hoffman Road: compression and siloxane removal (Sidebar 3). Keep in mind that the fuel contains a significant amount of moisture which should be removed before it is sent to the gas turbine. Alternatives: Install a refrigerated dryer in the gas line ahead of the compressor or opt for a dewpoint suppression system.

The siloxane removal system in Figs 3C and D, supplied by Parker Hannifin Corp's Purification, Dehydration & Filtration Div, Charlotte, NC, has these three stages of treatment:

- A high-efficiency, low-pressure-drop coalescing prefilter for removing solids, liquids, and aerosols down to 0.01 micron to protect the media beds.
- A regenerative adsorption system to remove siloxanes.
- A 1-micron after filter to protect downstream equipment from any dust particles created as the media wears.

Here's how the adsorption system works: Landfill gas flows down through a bed of adsorptive media which has an affinity for siloxane molecules and other contaminants. One bed in the twin-tower system is in service while the other is being regenerated or is on standby following regeneration. A service run typically lasts 24 hours, regeneration takes 12.

During regeneration, heated ambient air is passed upward through the media (direction is opposite to that of gas flow in the active adsorber). Heat breaks the bond between the media and the siloxanes; the latter are transported by the air stream, along with residual hydrocarbons, to the flare. When incinerated in the flare, the siloxanes morph into small crystals of silicon dioxide (sand) which dissipate into the ambient air.

The Parker system is relatively new. Brad Huxter, market development manager for the company's Green Energy Solutions product line, said Parker purchased the UK's dominick hunter ltd (official company name was in all lower-case letters) in 2006 and the siloxane removal system was among the company's assets.

After about 10 years of R&D work, the first commercial units entered service in fall 2007. Since then, more than 30 systems have been sold and are protecting fuel cells, reciprocating engines, and gas turbines from siloxane fouling. Huxter said specifications for new systems indicate the industry has settled on a performance spec that calls for less than from 5 to 10 mg/m^3 of siloxane in the product gas stream.

As an example of the system's value to engine operators, Huxter added that one owner reports its maintenance intervals have been

4. Gas produced in up to six anaerobic digesters flows from the spherical storage tanks highlighting the photo to the gas blending and compression station a few feet from the powerplant. Flare in the foreground is available for use when upset conditions dictate

extended three-fold compared to operation without siloxane removal. To date, only three siloxane removal systems have been purchased for clean-up of digester gas; the remainder are operating on landfill gas.

Digester gas and blending

Anaerobic digesters identified by the number 8 in the aerial photo convert primary sludge, and some secondary sludge, to a 650 Btu/scf gas (Fig 4). However, the flagging economy has adversely impacted production of digester gas as it has landfill gas. Expectations were that 350 scfm would be provided by the digesters,

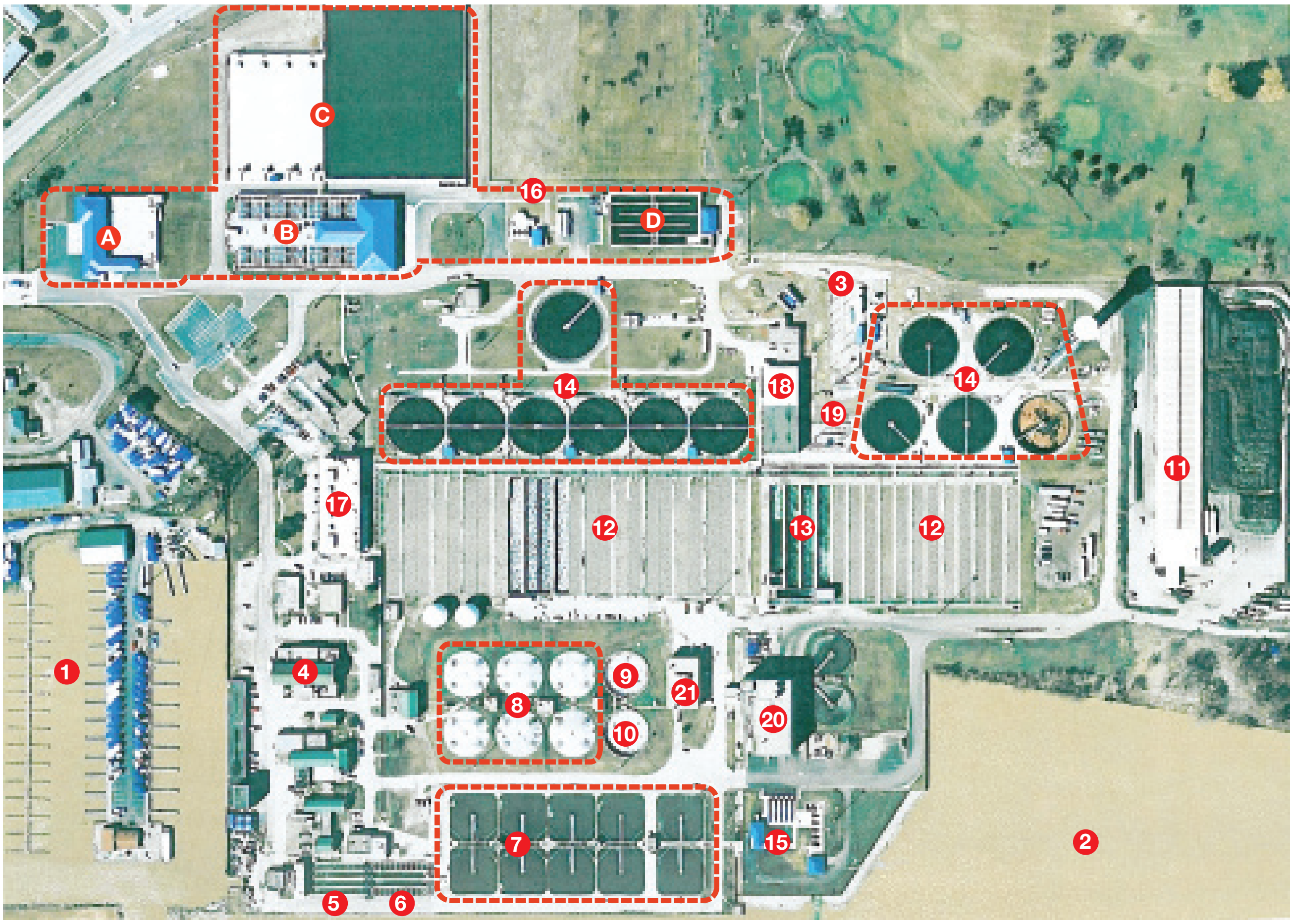
2. How the Bay View Wastewater Treatment Plant works

Bay View treats water from both sanitary sewers and storm drains. Water received from the center of Toledo is a mixture of the two; other storm drains in Bay View's service territory are released to receiving streams or pumped to the plant separate from sanitary-sewer wastewater.

Average dry-day flow (no precipitation) to the plant is 60-million gal; interestingly, it was about 25% higher before the recession. Typical wet-day flows can be three or four times greater than dry-day flows. Highest one-day peak rate to date was 405-million gal.

Capacity of the core plant is 168 million gal/day through primary treatment, up to 212 million gal/day can flow through secondary (biological) treatment. The wet-weather facility (WWF) added as part of a 2005 consent decree with the US EPA can process up to an additional 195 million gal/day. The WWF essentially accomplishes everything that the core plant does (primary and secondary treatment)—except for promoting the growth of anaerobic microorganisms to break down organic matter. That's not necessary for the very dilute wastewater stream (mostly storm drains) it handles. The wet-weather facility operates only about 10 times annually.

Bay View is operated by Toledo's Div of Reclamation, which also is responsible for all the wastewater storage and pumping facilities in the city. An onsite staff of 110 assures reliable and efficient 24/7 operation of the wastewater treatment plant within permit limits.



Legend

1. Boat basin (private property)
2. Maumee River
3. Cogeneration plant
4. Main pump station
5. Grit removal
6. Skim tanks remove oil, grease
7. Primary clarifiers
8. Digesters (fixed roof)
9. Equalization tank for primary and secondary sludge which then goes to the digesters
10. Storage tank receives sludge from digesters, pumps it to the dewatering facility
11. Sludge treatment facility. Private firm receives dewatered sludge, adds lime,and prepares it for use as a fertilizer which is sold commercially
12. Aeration tanks (9)
13. Chlorine contact tanks (4)
14. Secondary clarifiers (12)
15. Final-effluent pump station pumps treated wastewater to river during periods of wet weather
16. Wet weather facility
    A. Grit removal
    B. Ballasted flocculation process
    C. Equalization basins
    D. Chlorine contact tanks
17. Engine/generator building; also accommodates three aeration blowers
18. Aeration blower building
19. Substation
20. Sludge dewatering
21. Laboratory building

but they are delivering only 250 scfm.

Digester gas also is passed through a siloxane removal system of the type used at the landfill. Only difference is size: The landfill system is rated 2000 scfm, the system for the digesters has one-fifth that capacity.

Gas exiting the landfill siloxane removal system at about 45 psig travels 1.9 miles to the fuel preparation building adjacent to the cogen plant via a 10-in.-diam high-density polyethylene pipeline. By contrast, the journey for the 30-psig digester gas is only several hundred feet. Natural gas is supplied to the fuel preparation building as well (Fig 5B), by Columbia Gas of Ohio.

Gas blending and delivery

5. Gas blending and compression to the nominal 250 psig required at the engine happens in building **A**, located across the road from the cogen plant. Note the double-circuit fin-fan cooler—one circuit for screw-compressor oil, the other for cooling the mixed gas stream. Landfill, digester, and/or natural gases are blended as required before the mixed fuel goes to the compressor **(B-D)**. Compressed gas enters the top of the coalescing filter behind the compressor motor drive **(E)**, compressor oil at the bottom. Lines from both sections of the tank carry the respective fluids to the fin-fan cooler

Follow the flow of wastewater through the treatment plant using the aerial photo provided. Raw sewage is received by main pump station **(4)** after passing through fine bar screens to remove debris. First process step is grit removal **(5)** in aerated tanks. On a typical day, from 5 to 10 tons of sand, gravel, and other heavy solids are extracted from the waste stream and sent to the city's landfill for disposal.

Skimming tanks to remove oil and grease are next **(6)**. "Floatables" are collected here and transferred to scum separation tanks. Sludge settles to the bottom of the tanks and is pumped to the sludge thickeners.

First chemical treatment step is primary clarification **(7)**. Polymer is added to the wastewater stream to promote solids settling. Floatables are skimmed and sent to landfill; solids are extracted from the bottom of the clarifiers and pumped to the digester tanks **(8)**, which produce the methane gas burned by the new cogen facility.

Storage tank **(10)** receives sludge from the digesters before transfer to the dewatering facility **(20)**. There solids content is increased by belt filter presses before transport to the sludge treatment facility **(11)**.

Aeration tanks **(12)** mix air with wastewater to promote the growth of aerobic microorganisms which help break down organic matter. Secondary clarifiers **(14)** encourage floc, which contains microorganisms and organic material, to settle, leaving clarified water on the surface.

This process creates *return* activated sludge, which is sent back to the aeration tanks, and *waste-activated* sludge, which is processed in a dissolved-air floatation step. Latter adds polymer to the sludge and mixes it with pressurized water. Floatables are skimmed and pumped to the digesters, remaining water to the aeration tanks.

Chlorine contact tanks **(13)** disinfect clarified water with the powerful oxidizer between April 1 and October 31. A dechlorination step precedes discharge to the Maumee River **(2)** via the final-effluent pump station **(15)**.

6. Cogen plant (A) tour begins at the gas turbine **(B)** and follows the exhaust gas flow into the HRSG **(C)**. Fuel skid for the duct burner is in **(D)**. Walking around the back of the HRSG (drawings in Fig 7) to the other side of the plant you find the deaerator and boiler feed pumps **(E)**, steam turbine/generator **(F)**, condenser and circulating water pumps **(G)**, and makeup treatment system **(H)**. Control room, one flight up off the main floor looks out onto the plant's major equipment **(I)**

Gases are blended as required (Figs 5C and D), compressed (Fig 5E), and forwarded to the gas turbine. The same mixed gas can be used in the HRSG duct burner if the gas turbine is out of service.

However, the HRSG would not be supplementary fired with green gas at the same time the gas turbine is because there's not enough landfill and digester gas to support that mode of operation.

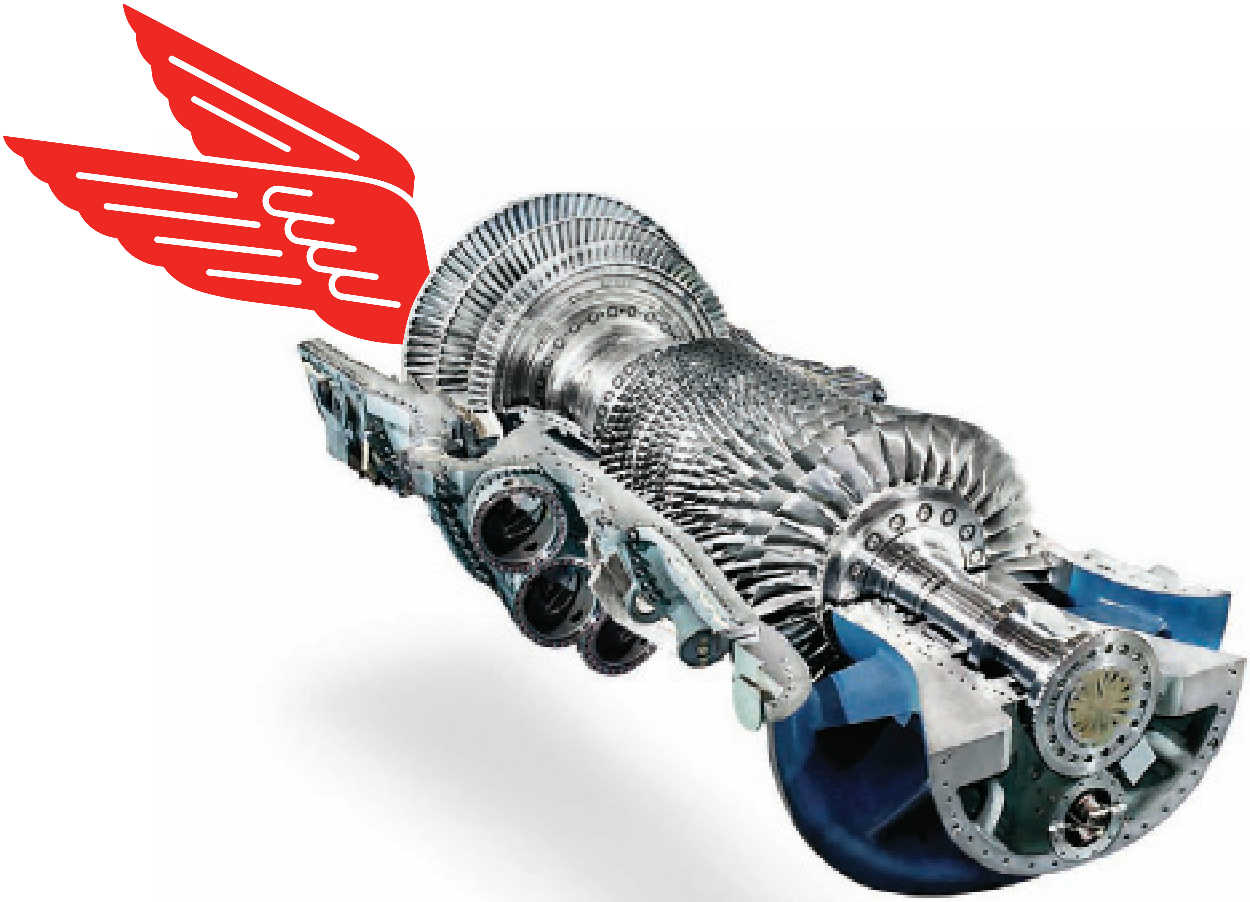
Interesting to note is that there are redundant LP gas compressors at the landfill, but only one HP compressor. Reason: The HP compressor is backed-up by natural gas, which is supplied at a pressure compatible with turbine requirements. There is only one LP compressor for the digester-gas circuit.

Schreidah said the gas blending and delivery system (purple area in Fig 1) works well. Quarterly, he added, gas is analyzed at the landfill, digesters, and at the blending station for siloxane, moisture, heating value, etc. Mixed gas entering the cogen plant (Fig 6A) passes through a small coalescer and final particulate filter just ahead of the gas turbine (Figs 6B and C).

The Solar Taurus™ 60 is rated at 5 MW when operating on green gas (capability is based on 1500 scfm of landfill gas, 350 scfm of digester gas). The project manager explained that the plant was commissioned on natural gas first and then on the green gas mixture to verify contractual requirements.

Project goal, Schreidah continued, is to use the green gases to sustain the electrical needs of the Bay View plant in dry weather. This is achieved most days. Depending on gas availability and other factors, the Taurus might burn (1) any one of the three gases by itself, (2) a mixture of any two gases, or (3) a mixture of all three.

Designing gas turbine combustion and control systems to accommodate



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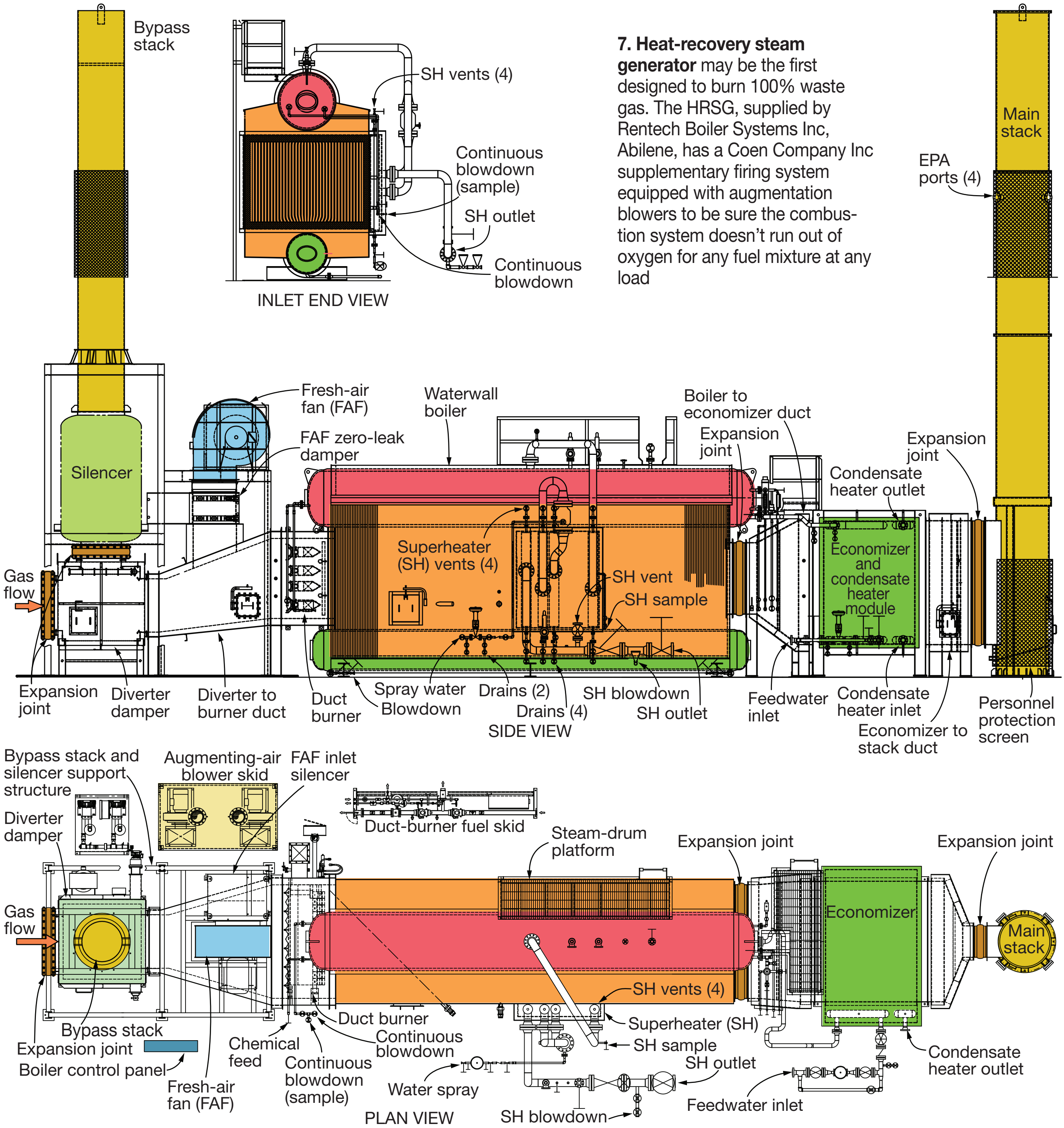

7. Heat-recovery steam generator may be the first designed to burn 100% waste gas. The HRSG, supplied by Rentech Boiler Systems Inc, Abilene, has a Coen Company Inc supplementary firing system equipped with augmentation blowers to be sure the combustion system doesn't run out of oxygen for any fuel mixture at any load

a wide range of fuels requires considerable know-how. At Bay View the challenge was to assure safe, efficient, and reliable operation on natural gas with a heating value of about 1000 Btu/ft^3 as well as on landfill gas with a heating value half that amount.

Recall that gaseous fuels normally are classified by their Wobbe Index, a parameter that accounts for variations in fuel density and heating value. It relates relative heat input to a combustion system of fixed geometry at a constant fuel supply pressure. If two fuels have the same Wobbe Index, direct substitution is possible and no change to the fuel system is required. A rule of thumb is that gases having a Wobbe Index within 10% of what the combustion system is arranged to handle can be substituted without making adjustment to the fuel control system or injector orifices.

Obviously, the range of Wobbe Indexes for the fuel combinations possible at Bay View are well beyond the 10% variation that can be accommodated by a standard combustion system. What Solar Turbines provided for the Toledo project was its dual-gas wide-Wobbe fuel assembly equipped with dual-gas low-Btu wide-Wobbe injectors shown in Fig 6B. Details on how the combustion system works were not available.

A unique HRSG

The heat-recovery steam generator, designed and built by Rentech Boiler Systems Inc, Abilene, Tex, is, perhaps, the first HRSG designed to burn 100% green gas as a supplemental fuel (Figs 6C and D, and Fig 7). Such innovation is in sharp contrast to the balance-of-plant (BOP) equipment, which basically is "standard issue" (Figs 6E-I).

On a typical dry day, gas-turbine


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TURBINE ENERGY SOLUTIONS
THE NEW COMPETITION
Melody Manning, Sales Manager
281.227.0090
sales@turbineenergysolutions.com

3. What's all the fuss about siloxanes?

Mark Hughes of Solar Turbines Inc provided a backgrounder on siloxanes of value to all considering green gas for power generation. Siloxanes, he said, are a group of unreactive chemicals used primarily as a replacement for oils in cosmetics—such as hand creams, stick deodorants, etc. They have an oily feel, but evaporate at body temperature.

There are hundreds of different species in this family of chemicals. Some are water soluble, Hughes continued, but these are less prevalent than the non-water soluble species. That's a positive because they are the most difficult to capture.

Regarding experience, Hughes said his research has not revealed any documented evidence of gas-turbine component degradation caused by siloxanes—at any firing temperature. And Solar's experience confirms that. The company's first turbine to operate on landfill gas—a Centaur®40 at the Puente Hills Landfill in Whittier, Calif—has run more than 50,000 hours between overhauls with no ill effects.

Hughes believes there about 110 gas turbines operating on landfill or digester gas—fewer than 10% of them with the benefit of siloxane removal. Siloxane residual is invariably found on hot-gas-path parts (combustion liners and turbine airfoils) and typically results in a minor impact on performance, but no adverse effect on emissions.

Removal of siloxane deposits does not complicate overhaul processes or noticeably add to their cost.

However, Hughes suggested removing siloxanes from any fuel burned in reciprocating engines. It fouls plugs, coats cylinder heads and valves, and impedes the combustion process; CO emissions increase dramatically over time. Because of the potential for siloxanes to foul Solar's Mercury™ 50 GT recuperator, siloxane removal is strongly recommended for that turbine.

output on 100% green gas would be 5.1 MW and the HRSG would generate around 19,000 lb/hr (about 22,000 lb/hr were the GT burning natural gas) with the duct burner turned off. The steam turbine (ST, Dresser-Rand Co) would produce a nominal 1.5 MW—its minimum output.

The supplementary firing system, provided by Coen Company Inc, Foster City, Calif, normally burns natural gas because, as noted earlier, the GT consumes all the landfill gas and digester gas produced at this time. With the 65-million-Btu/hr duct burner at full fire on natural gas and the gas turbine operating at rated output, the boiler generates 77,000 lb/hr of 650-psig/700 steam, good for 5.1 MW from the multi-stage steamer.

The bypass stack and damper between the GT and HRSG are critical because they provide the flexibility to operate the gas turbine if downstream equipment—boiler or steamer, for example—is not available, and allow the Rankine Cycle to operate if the GT is out of service.

The fresh-air fan (FAF) enables duct-burner operation if the gas turbine is unavailable. It is designed to match the mass flow through the HRSG that the GT would normally provide. In this service mode, the steamer can produce 3 MW when firing green gas or natural gas. Obvious choice would be landfill and/or digester gas if available.

Use of special augmentation blowers (shown above the fresh-air fan in Fig 7 plan view) is required in addition to the FAF when burning green gas, to assure sufficient oxygen for complete combustion under all operating conditions. Note that no means is provided for controlling air flow from the FAF; steam pressure is controlled by modulating the fuel valve when the gas turbine is not in operation.

Ellman said upgrade of the HRSG to produce full output from the steam turbine with the GT shut down was considered, but that would have required having the boiler oversized, meaning it would operate at significantly lower efficiency most of the time. The economic penalty could not be justified.

Rentech's project manager, Cory Goings, PE, told the editors that the superheater visible in the middle of the waterwall section of the HRSG was arranged in two passes with tubes oriented horizontally. Saturated steam enters the downstream section of the superheater (easy to see in the plan view), exits to a desuperheater, then re-enters the furnace area for a second pass. A two-pass design was necessary to control steam temperature under all firing conditions.

The economizer and condensate preheater are arranged in a separate section of the HRSG downstream of the waterwall boiler. The preheater has finned tubes of a duplex stainless material to minimize corrosion. The 0.375-in.-high fins also are stainless and arranged two fins per inch. Applied Heat Recovery LLC, Fair Oaks Ranch, Tex, made the economizer/preheater section for Rentech. Both companies are members of the American Boiler Manufacturers Assn, Vienna, Va.

Operational notes

Operation and maintenance of the Bay View cogen plant is under long-term contract to Solar. The contract provides for a bonus when plant availability is above the number specified, a penalty when below. Rick Bullard, Solar's Bay View contract manager (plant manger) has more than two decades of industrial power experience, including combustion of landfill gas. He has a staff of six for 24/7 operation.

It made dollars and sense to have the complex plant run by an experienced team with direct access to engineers with first-hand knowledge of green gas treatment and combustion. Plus, a data feed to the Monitoring and Diagnostic Center at Solar headquarters assures that any operational anomalies get a second look.

Schreidah said the plant has successfully tested its ability to export power to Toledo Edison; plus, the utility has authorized two-way operation based on the positive results of its circuit-switcher test. At this time, the plant will only take power from the utility if need be.

This article would not be complete without mention of the cogen plant's air permit, which specifies emissions limits on a tons-per-year basis for carbon monoxide, volatile organic compounds (VOCs), NO_x, and SO_2 for both the gas turbine and HRSG.

Emissions limits are identified for each combustion source because the GT and boiler can be operated independently of each other.

The limits adopted by the Ohio EPA are based on the plant's use of "best available control techniques and operating practices." The state EPA noted that the design of the "emissions units" and the technology associated with the current operating practices satisfy its best-available-technology requirements.

Schreidah wrapped up the interview by saying that the air permit would not impose any operational restrictions on the combined-cycle cogen plant. Based on the quantities of landfill and digester gases available, he continued, the Bay View project always will be in compliance with the air permit. CCJ

'Perhaps the best 7F meeting ever'

That's what many of the more than 180 owner/operators attending the 2010 7F Users Group Conference and Vendor Fair told Chairman Richard Clark of SCE Energy and Vice Chair Sam Graham of Tenaska Inc as the five-day meeting drew to a close last May. It was quite a compliment given the rich history of the group, which celebrates its 20th anniversary in 2011.

Graham, the maintenance manager at the 3 × 1 Tenaska Virginia Generating Station (TVGS), took the reins from Clark, operations manager for Mountainview Generating Station's two 2 × 1 combined cycles, at the end of the conference and will chair the group through the upcoming meeting. Ben Meissner of Progress Energy is the vice chair. Other members of the 2010-2011 steering committee are identified in Sidebar 1.

Dr Robert Mayfield, who serves on the steering committee, told the editors that one of the reasons for the very positive unsolicited comments was a change in conference format to allow for a more robust open forum between the users and GE engineers. The owner/operators had more than a day and a half of face time with the OEM's experts and thoroughly covered such timely gas-turbine topics as:

- End-of-life recommendations.
- Combustion and hot-gas-path (HGP) inspections.
- Enhanced-compressor updates.
- Outage lessons learned.
- Best practices and safety.
- Control-system enhancements.

In addition, there was a session on the users' top-10 GE issues, another on the capabilities of GE Energy Services' repair shops, and a half-day D-11/A-10 steam-turbine workshop. Finally, the OEM's team demonstrated, via its so-called Knowledge Café, the following new tools for customers: self-help portal, outage optimizer, onsite support, parts edge, and power smarts.

Mayfield assures that the 2011 meeting will exceed expectations once again. The Houston location gives users the opportunity for a firsthand look at GE's repair facilities; tours will be conducted on Monday, May 9. Highlights of the upcoming conference are presented in the box, under the group's logo. For more detail and program updates as changes occur, plus information on how to register, visit http://ge7fa.users-groups.com.

Keep in mind that you must be *invited* to attend the 7F meeting. Owner/operators of Frame 7F, 9F, and 6FA engines interested in participating in the 2011 conference who are not *registered* members of the 7F Users Group are urged to submit their professional profiles as soon as possible via the membership drop-down menu at http://ge7fa.users-groups.com/Membership/UserCandidate.shtml.

Companies wanting to participate in upcoming meetings as a sponsor (Sidebar 2) and/or exhibitor must complete a profile for review by the steering committee. Do this at http://ge7fa.users-groups.com/Membership/AffiliateCandidate.shtml. Only companies approved by the committee receive invitations.

7F USERS GROUP

2011 Conference and Vendor Fair

May 9-13 • Westin Galleria • Houston

Agenda highlights for user attendees:

Monday, May 9. Golf tournament (8 am shotgun start, registration required, fee complimentary for users); optional tours of GE shop facilities; optional afternoon sessions (1-6 pm); keynote address (6:30 pm); welcome reception/dinner (7:30 pm).

Tuesday, May 10. Breakfast (7-8 am); general session (8 am-noon, 1-3:45 pm); lunch (noon-1 pm); vendor presentations (4-5:45 pm); vendor fair (6-9:30).

Wednesday, May 11. Breakfast (7-8 am); general session (8 am-noon, 1-2:45 pm); lunch (noon-1 pm); vendor presentations (3-5:45 pm); vendor fair (6-9:30).

Thursday, May 12. Breakfast (7-8 am); general session (8 am-noon, 1-6 pm); lunch (noon-1 pm); GE product fair (6-9:30).

Friday, May 13. Breakfast (7-8 am); D11/A10 steam turbine workshop (8 am-noon).

Budget info: Conference fee, $400 before April 15; hotel room rate, $129 plus taxes per night.

The summary agenda may be a helpful addition to your request for permission to attend the May meeting. It clearly shows this conference is a non-stop learning experience that starts daily at 7 am with informal discussions over breakfast, migrates to in-depth technical sessions from 8 to nearly 6 pm with only an hour break for a collaborative lunch among colleagues, and concludes with a vendor fair from 6 to 9:30 pm (different companies participate each day).

Do the math: This translates to 14.5 hours a day, or more "classroom" time in one week than you would get in one semester for a three-credit college course. Think of the 7F meeting as a compressed high-level education on one of the world's most sophisticated pieces of rotating machinery for less than $2000—including conference registration, hotel accommodations, and air fare. (Food is not a cost factor: Sheila Vashi and her colleagues from Marietta (Ga)-based Vision-Makers will make sure you're well fed.)

1. Steering committee, 2010-2011

Chairman: Sam Graham, *Tenaska Inc*

Vice Chairman: Ben Meissner, *Progress Energy*

Treasurer: Peter So, *Calpine Corp*

Richard Clark, *SCE Energy*
Ed Fuselier, *Direct Energy*
Jeff Gillis, *ExxonMobil Chemical*
Art Hamilton, *Calpine Corp*
James Harbaugh, *Tampa Electric Co*
Bob Holm, *OxyChem*
Robert Mayfield, *Tenaska Inc*
Dave Merkley, *Tenaska Inc*
David Such, *Xcel Energy*
Eugene Szpynda, *New York Power Authority*
Paul White, *Dominion Energy*

The answer to the "What's in it for the company?" question that you'll probably get from management: The best practices and lessons learned from the many user presentations, and the knowledge gained on technological advances from the vendors, are sure to pay a minimum 10-fold return on the "tuition" investment over the next year alone (Sidebars 3 and 4).

User presentations, discussion

First topic on the agenda of the closed user sessions at 7F meetings is the compressor. It usually generates more interest than the combustion, turbine, generator, and auxiliaries segments of the program because the open discussion encom-

2. 2010 sponsors

Platinum sponsor

GE Energy, *Atlanta, Ga*

Gold sponsors

PIC Group Inc, *Marietta, Ga*
Young & Franklin Inc, *Liverpool, NY*

Silver sponsors

Advanced Turbine Support Inc, *Gainesville, Fla*
Allied Power Group LLC, *Houston, Tex*
ConocoPhillips, *Houston, Tex*
Dresser-Rand Leading Edge Turbine Technology Services, *Houston, Tex*
Megawatt Machine Services, *Somerset, NJ*
PSM-Power Systems Mfg LLC, *Jupiter, Fla*
Trinity Turbine Technology LP, *Iowa Colony, Tex*

Bronze sponsors

Analysts Inc, *Hoffman Estates, Ill*
COMBINED CYCLE Journal, *Las Vegas, Nev*
Donaldson Company Inc, *Minneapolis, Minn*
GTE-Gas Turbine Efficiency, *Orlando, Fla*
HRST Inc, *Eden Prairie, Minn*
ITH Engineering Inc, *McHenry, Ill*
KEMA, *Burlington, Mass*
NAES Corp, *Issaquah, Wash*
ProEnergy Services, *Sedalia, Mo*
Sulzer Turbo Services, *LaPorte, Tex*
TOPS LLC, *Humble, Tex*
ZOK-Zokman Products Inc, *Ft Wayne, Ind*

3. Vendor presentations expand the 7F program in 2010

Allied Power Group, www.alliedpg.com, *7FA+e R1 nozzle coating and qualification,* Aaron Frost.

American Chemical Technologies Inc, www. americanchemtech.com, *Novel non-varnishing PAG (polyalkylene glycol)-based synthetic turbine fluid,* Dr Govind Khemchandani (Dow Chemical Co).

Analysts Inc, www.analystsinc.com, *Cross relief valve: Controlling varnish in servo valves,* Hans Overgang (AnsaldoThomasson).

BFI Automation USA, www.bfi-automation.com, *Fiberoptic flame monitor eliminates liquid cooling,* Hank Marsman.

ConocoPhillips, www.conocophillips.com, *Best practices for maximizing performance of varnish control turbine oils,* Timothy Langlais.

Cutsforth Inc, www.cutsforth.com, *Cause and prevention of collector-ring fires,* Michael Biroschak.

Davidson Instruments, www.davidson-instruments.com, *Combustion dynamics monitoring using temperature-tolerant fiberoptic transducers,* Richard Lopushansky.

GTE-Gas Turbine Efficiency, www.gtefficiency.com, *Application of automating the process of combustion tuning on large industrial gas turbines,* Marcus Turner.

JASC-Jansen's Aircraft Systems Controls Inc, www.jasc-controls.com, T*he future of simple, combined, and IGCC liquid-fuel-system reliability in dual-fuel turbine applications,* Schuyler McElrath.

Liburdi Turbine Services, www.liburditurbine.com, *The role of metallurgical analysis in gas turbine maintenance,* John Bottoms.

Megawatt Machine Services, www.megawattmachine.com, *Control valve solutions: A word of wisdom,* Andy and Steven Balough.

Power Systems Mfg LLC, www.psm.com, *PSM's aftermarket 7FA product offerings, component, and system experience,* Tim te.Riele.

Strategic Power Systems Inc, www.spsinc.com, *An automated approach to asset management: One customer's experience,* Thomas Christiansen.

Tetra Engineering Group Inc, www.tetra-eng.com, *Troubleshooting HRSG performance problems and operating limitations with static and dynamic computer simulation,* Dr Frank J Berte.

Young & Franklin Inc, www.yf.com, *Ruggedized primary fuel control assemblies (Dither),* Christopher Yeckel.

4. Saluting the 2010 user discussion leaders, speakers

Tony Antonucci, *American Electric Power Co*
Richard Clark, *SCE Energy*
William (Stacey) Davis, *Guadalupe Power Partners LP (now Turbine Maintenance & Plant Services LLC)*
Ed Fuselier, *Direct Energy*
Dan George, *American Electric Power Co*
Bob Holm, *OxyChem*
Min Ki Kim, *Korea Southern Power Co*
Shonosuke Koga, *Osaka Gas Co*
Peter Margliotti, *Armstrong Energy LLC*
Robert Mayfield, *Tenaska Inc*
Marshall McDuffy, *The Southern Company*
Ben Meissner, *Progress Energy*
Dave Merkley, *Tenaska Inc*
Brian Pavlick, *Dominion Energy*
Lonnie Simon, *OxyChem, Taft Cogeneration*
Tony Shook, *OGE Electric Services Inc*
Ed Sundheim, *North American Energy Alliance LLC*
Munenori Ukai, *Osaka Gas Co*
Paul White, *Dominion Energy*

passes the air inlet house as well as the compressor and its issues.

The 2010 compressor session ran the entire morning of Day Two and featured several of the more than one dozen user presentations made in Atlanta. The session kicked-off with a presentation on tip-crack experience at two plants, one a five-unit peaking facility and the other a 2 × 1 combined cycle.

Tip cracking

Recall that tip cracking of R0 and R1 compressor blades is caused by rubs and is an acknowledged fleet-wide problem; consult Technical Information Letter (TIL) 1509, first issued in May 2005. The OEM identified the following among the possible causes of rubs: over speed, fast starts, open doors, foundation distress, and wet operation.

The speaker had long-term knowledge of the cracking issue. The peaking plant went commercial in 2001 and the combined cycle in 2002 and both have suffered chronic R1 rubs and have experienced cracking and tip loss. Important takeaways from this presentation: Hard rubs are conducive to tip liberations over time and the guidance offered in TIL-1509 may not be sufficiently rigorous to assure the level of equipment protection most owner/operators desire. Further, poor blending and tip surface finish can create sites from which cracks can propagate.

Peaker experience. One 7FA suffered the loss of a corner at the tip of an R1 blade within a year of COD. A fluorescent penetrant inspection (FPI) was conducted to verify blade integrity after every eight starts until repairs could be made. At the next outage, the R0 and R1 blades were tip-ground and the damaged blade blended.

Tip cracking occurred on one R1 blade in 2003 and on another R1 blade in 2004. After the crack was found in 2004, the R1 blades were "roof-topped" to remove any microcracking that may have started from burrs (cracks start on the outer edges of the blade tip).

The roof-topping process involves grinding off the square edges at the top of each rotating blade from the leading edge to the trailing edge. The grinding angle is arbitrary; goal is to remove about 20 mils of material. There is no impact on blade clearances.

For the next several years, borescope inspections and TIL-1509 inspections were conducted annually. No further tip cracking was reported during this period. But damage to S0 and S1 stator vanes on one unit was found during the fall 2008 inspection. A 30-day outage was planned for the following spring to replace the S0 airfoils. By then, the affected engine had accumulated just over 3200 fired hours of operation and nearly 450 starts (an average of about 60 starts per year).

During the outage, tip loss was found on two R1 blades, along with collateral damage (Fig 1). For the blade at the left, the crack initiated from one of the blend marks on the convex side of the airfoil tip in the roof-top area, 2 in. from the leading edge. The failure was attributed to poor roof-top repair.

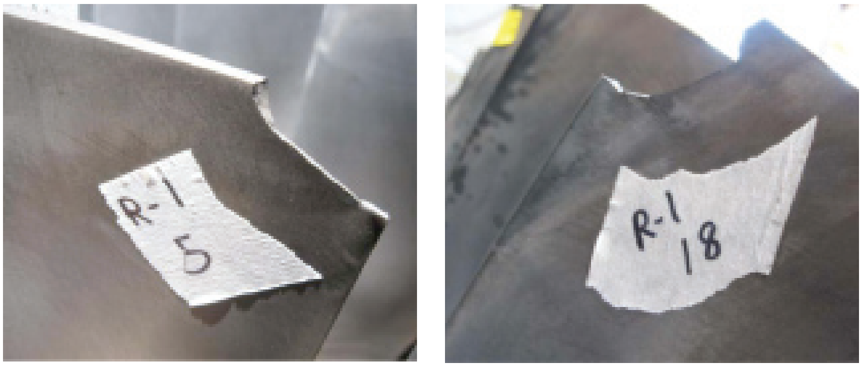
The rotor was not removed to replace the damaged stator vanes. A borescope identified the affected lower-half vanes and the OEM's stator removal tool was used to remove the necessary vane segments. The speaker said the tool was cumbersome to maneuver and destructive to the segments; however, vanes were not damaged.

S0 and S1 vanes were replaced using the manufacturer's NUV (non-uniform vane) stator solution to limit the frequency response of R1 blades. One lower-half S2 segment and several upper-half S2 segments were replaced as well.

Additional work included pinning of shims, opening of R0 and R1 clearances, blending of all damaged rotat-

Sheila Vashi

7F steering committee. Top row (l to r): Dave Merkley, Eugene Szpynda, Ed Fuselier, Jeff Gillis. Middle row: Paul White, Sam Graham, Dan Giel, Bob Holm. Bottom row: Richard Clark, Peter So, Jim Harbaugh, Ben Meissner. Camera shy: Art Hamilton, David Such, and Robert Mayfield



1. Classic tip crack is shown at the left with crack initiation about 2 in. from the leading edge. Impact caused the damage at the right

2. Stake marks indicate this is the third set of R0 blades. The next change-out will require the OEM to install its "Biscuit" mod before installing the blades

ing blades, and polishing of R0 and R1 blade tips to a more demanding specification than recommended by the OEM. A third-party contractor verified proper tip grinding using the latest UT (ultrasonic test) tools.

The combined cycle gas turbines suffered heavy rubs within six months of its COD as was the case at the peaker station. But as the speaker said at the outset, hard rubs are conducive to tip liberations over time. In this case, it took six years, nearly 29,000 fired hours and more than 1100 starts for a 3 × 3 in. piece of an R1 blade to liberate. A root-cause analysis (RCA) revealed the tip fracture indeed was from rub-induced stress with crack propagation caused by high cycle fatigue (HCF).

Borescope inspections had been performed semi-annually and TIL-1509 conducted annually. In spring 2006, an R0 tip loss was blended and an HGP inspection was done in spring 2008. The compressor was carefully examined after the spring 2009 borescope inspection revealed the piece missing from the R1 blade.

The OEM's team found more than 500 indications but was reluctant to condemn the rotor, the speaker said, believing excessive blending and restricted operation were an option—theoretically, at least. The owner opted to purchase a new rotor and perform a Package 5 enhancement. Outage was completed 51 days from discovery.

End notes. (1) A lesson learned: Record every compressor part removed and make sure you have all the parts (and tools) you should have before buttoning-up the unit. Four days after this outage, a stator blade that had been removed was found at a compressor bleed valve.

(2) A subject of ongoing debate: Might a vibration profile and off-normal compressor discharge pressures/temperatures have indicated an impending tip liberation. Blade health monitoring capabilities only recently have been installed at some M&D (monitoring and diagnostic) centers; time will tell.

(3) Lingering questions: Can you grind down a tip rub to healthy material and repair? Might the wound be permanent?

R0 dovetail cracking

An owner with considerable 7FA O&M experience reported multiple changes of R0 blades on a flared compressor with uncambered inlet guide vanes (IGVs). In spring 2008, he said, an OEM crew removed the original set of non-P-cut R0 blades from the unit after 233 fired starts, 2781 fired hours, and 10 trips. Dovetail cracking found during a scheduled inspection using phased-array UT was the reason for replacing the row with a new set of standard non-P-cut blades.

Those new blades failed in the same manner, but 17 months later after only 115 fired starts, 1611 fired hours, and one trip. The second set of R0 blades was replaced by jacking up the bellmouth case 18 in. without removing the turbine compartment roof or forward wall. Note that an Alumazite® coating was applied to the R0 dovetail side slot prior to installing the third set of blades. Also worth noting: The third set of blades has the same part number as the second set, but the airfoil profile is different (Fig 2).

Inlet guide vanes (IGVs) were not changed as part of this project. However, changes were required to IGV angle and startup logic. Specifically, IGV mechanical stops were re-established to allow an operating range of from 20.5 deg (fully closed) to 92.5 deg (fully open).

In addition, control-constant mods were made to change IGV position during startup and the speed at which IGVs open. IGV position while on turning gear had been 26 deg, now 20.5; IGV angle during startup was changed from 28.5 deg to 24; turbine speed when IGVs open was 85.5, now 84.8; IGV position at full-speed no load (FSNL) remains the same at 45 deg.

In wrapping up, the speaker stimulated the group with the following comment: Buying new blades requires an exchange-type program. Simply put, when you buy new blades, the OEM makes you turn in the set removed. This means you can't hire a metallurgist to conduct your own failure analysis and it raises questions regarding further use of blades inspected and found healthy.

For example, what did the OEM do to recertify those "healthy" blades? How good are the blades after having been subjected to stresses that cracked other blades in the same row? One attendee suggested having a third party verify blade integrity before installation. Another said you might want to consider using recertified blades in machines that would not have more than a couple of hundred starts before the next overhaul. Yet another user essentially told the group not to worry by sharing that his plant had one unit with 30,000 hours on recertified blades.

By show of hands, roughly two dozen owner/operators in the room said they have units that had experienced R0 dovetail cracks.

Clashing conundrum

Clashing of rotating blades and stationary vanes in Frame 7 compressors has been reported by many users, as well as by Rod Shidler of Florida-based Advanced Turbine Support Inc, at recent meetings of the 7EA and 7F Users Groups.

The opportunity for owner/operators to "compare notes" on common issues of importance, and their solutions, suggests attendance at user-group conferences be considered "mandatory." If not from colleagues, where else would you expect to learn about the next problem that will keep you up nights?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3. Damage to trailing edge of rotating blades. More specifically, deformation and some lift-up of material near the platform at the trailing edge

4. Damage to S2 leading-edge tip. Most damage was from the 6 o'clock position to the horizontal joint

5. Cropped S2 leading edge during an outage. Technicians took precise measurements of the damaged area on each vane then cropped the worst airfoil and cut back the entire row to the same point

To illustrate: At a recent 7EA meeting one user discussed clashing on five of six peaking units at one site, noting that clashing was found on the sixth unit a year later and only 20 fired starts/60 fired hours since the last borescope inspection when it had received a clean bill of health. Several other plants represented at the meeting reported similar findings.

The OEM presented at the same meeting, quickly addressing the clashing issue. Its representative said 12 incidents were reported at five sites (a poll of attendees alone revealed more than that number of incidents) 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 presenter with the six 7EAs affected by clashing reported that the OEM considered clashing insignificant in terms of posing a risk to continued operation. It advised that the damaged areas be examined by FPI, blended smooth, polished, and flapper-peened by one of its qualified technicians at the next opportunity.

As for root cause, there was no answer. The OEM considered that it might be a system-level assembly issue causing casing distortion or concentricity/alignment offset.

Location: 6 o'clock. Discussions among 7EA users focus on R1/S1 clashing; among 7F users the focus is R2/S2. No matter: In virtually all instances, reports indicated the clashing was concentrated at or near the 6 o'clock position.

The first 7F speaker on the subject offered the following information on the six gas turbines affected by clashing at his company:

- All the engines are installed in 2 × 1 combined cycles. All went commercial in the 2001 timeframe; regular borescope inspections were "clean" up to within six months of the event.
- Five of the compressors are unflared and have cambered IGVs (four of these units are at the same site); one is flared with uncambered IGVs. Clashing of the four units at the same site occurred between 1050 and about 1200 fired starts and 35,000 and 45,000 fired hours (Figs 3 and 4).
- Clashing on one unflared unit was caused by an IGV failure and affected both R2/S2 and R3/S3.
- The single event on a flared compressor was R3/S3 and occurred at a site with four flared units.

Damaged blades and vanes were cropped as shown in Fig 5. Interestingly, only one machine showed a drop off in performance after cropping, and that was very slight. The owner conducts annual borescope inspections to verify compressor health and has initiated an RCA and a proactive monitoring program. Last includes putting a trigger file in the Mark V control system that looks at step changes in vibration and other critical variables, and collecting pressure and vibration data through borescope plug holes with special transducers.

A quick poll of the audience before the next speaker presented on his company's experience with 7FA clashing revealed that attendees also responsible for 7EAs said 17 of those machines had been damaged by R1/S1 clashing.

Peaker clashing. This case history focuses on clashing of R2 blades and S2 vanes on three dual-fuel simple-cycle 7FAs at one site (Figs 6 and 7). All engines are equipped with unflared compressors, static filters, and cambered IGVs. Each had recorded approximately 400 fired starts and 2500 fired hours when the indications were discovered during routine annual borescope inspections at the end of the winter run in spring 2008.

Here are some details on the unit that suffered the most severe clashing:

- It had recorded 39 fired starts since the previous borescope inspection, when no damage was evident.
- The R2 blade-rub area on trailing-edge roots was approximately 1 in. long; depth of penetration was 0.125 and 0.375 in.
- Seven S2 vanes were damaged at the leading edge.

The owner/operator made several changes to its O&M procedures after examining the results of the March 2008 borescope inspection, including these:

- Perform a 360-deg borescope inspection of R2/S2 at the end of the winter run season (typically at the end of March) or after 20 starts at or below 32F.

6, 7. R2 blade trailing-edge (left) and S2 vane leading-edge (right) clash indications typically look like this when viewed through a borescope


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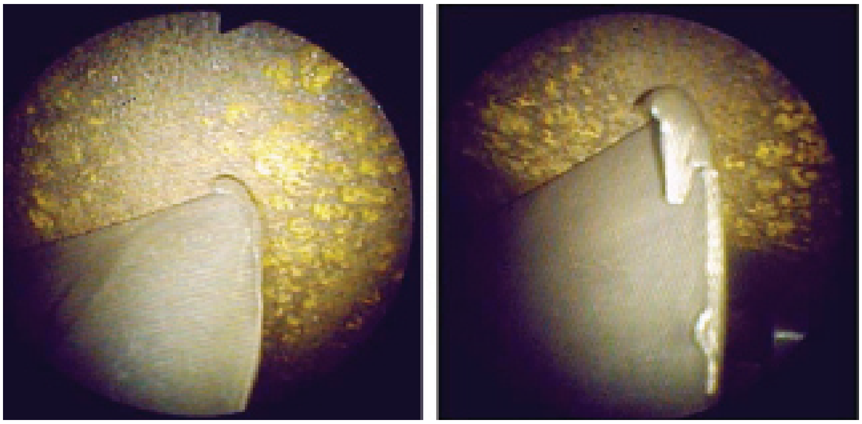
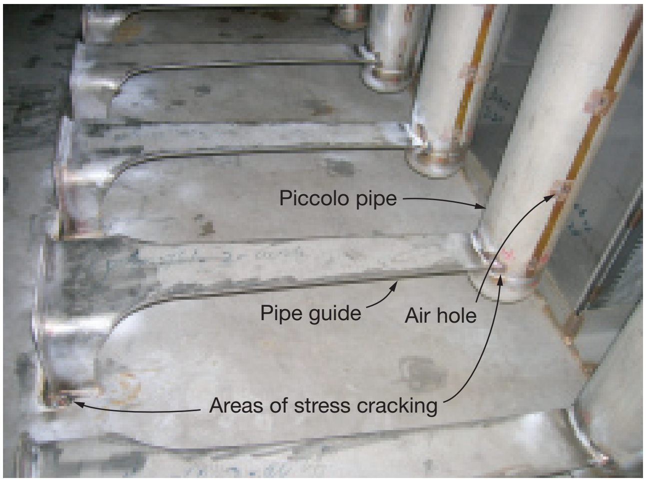
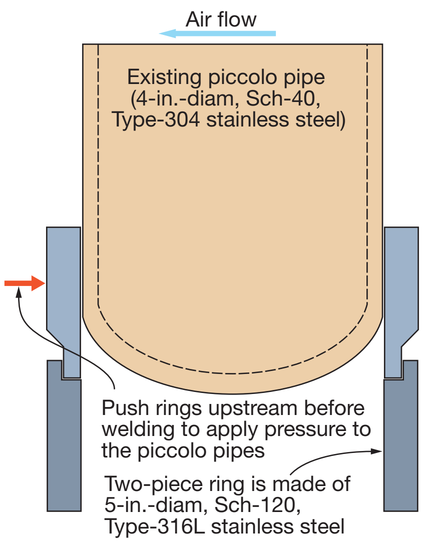
NEM
USA



8. Smeared and rolled metal on adjacent stator vanes (damage area on vane at left, 1 × 0.25 in.; at right, 1 × 0.375 in.) proved clashing was increasing in severity since its discovery a year earlier



9. Stress cracking is relatively common on piccolo pipes where they attach to their respective pipe guides and in the areas where pipe guides attach to the floor. Stress cracks also may be found in the duct floor and in the pipe guides themselves



10. Redesigned guide sleeve for piccolo pipes is easy to make and doesn't require cutting the existing pipes

- Record clearances between the R2 trailing-edge root and the S2 vane leading-edge tip (at a point adjacent to the rotor body) on all 7FAs in the company's fleet when personnel have access to take those measurements. Do the same for R3/S3.

A follow-up borescope inspection was conducted in July 2008 after a couple of dozen more fired starts. The damage had not worsened since its discovery. But the good news didn't last for long. The annual inspection in spring 2009 indicated that clashing damage had increased after the winter run (total of 30 fired starts since the spring 2008 check-up).

The unwelcome observation prompted management to authorize a more extensive borescope inspection of the entire R2/S2 row. Results: Damaged blades numbered 10; S2 vanes were described as having "smeared and rolled metal" (Fig 8). Next, the trailing edges of all R2 blade platforms, and the first 2 in. of the blades' trailing edges, were examined using the latest eddy current diagnostic tools. Close inspection of the damage areas on the 10 blades affected (pressure and suction sides in the trailing-edge platform area) revealed no recordable indications.

Engineers continue to ponder the possible causes of clashing and how to prevent it. The first presenter on the subject thought it might be trip-related given there were no indications on one of its units following a no-trip year and there were indications the year a trip had occurred.

A check of thrust-bearing clearances offered no clues. The thought that clashing might be related to cold starts cannot be supported because of incidents reported at one plant (at least) where no freezing temperatures were experienced. Some experts now think the gremlin may be a surge event, but this cannot be confirmed.

Learn more on the subject by attending the 2011 meeting in Houston.

Inlet bleed heat

Cracking of piccolo pipes for the inlet bleed heat system has been discussed recently at several conferences focusing on maintenance of large GE frames. Recall that the IBH system injects hot compressed air into the inlet air stream to prevent icing at the compressor inlet. A problem experienced by many owner/operators is stress cracking on the piccolo pipes where they attach to their respective pipe guides (Fig 9). Simply welding the cracks was not a solution; they just cracked again.

The solution offered to 7F User Group attendees, which had been suggested by at least one other user a year or so earlier, looks like it might qualify for an industry best practice and put the subject to rest. The two-piece support system (Fig 10) which replaces the existing guide sleeve is easy for plant personnel to install and costs less than 20% of the OEM's recommended solution.

New supports were installed during an HGP inspection in 2009 and have solved the cracking problem (Fig 11). The speaker offered the following budget in round numbers: 5-in.-diam, Sch-120, Type-316L stainless steel pipe—$5000; 10 hours of machining time—$1000; two welders for four days—$3000; and NDE inspection—$1000.

Compressor discussion

The open discussion session following the compressor presentation went on for about an hour before the subject shifted to the turbine end of the machine. Here are some snippets from the compressor exchange:

- One user familiar with the OEM's new compressor wash system reported seeing some erosion of concern.
- Filter-house air leaks: Sometimes looking for sunlight while standing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11. Installation of the new guide sleeves went according to plan and has eliminated the need for annual crack repair

12. Bucket damage at the leading edge and coating detachment resulted from forward migration of the airfoils

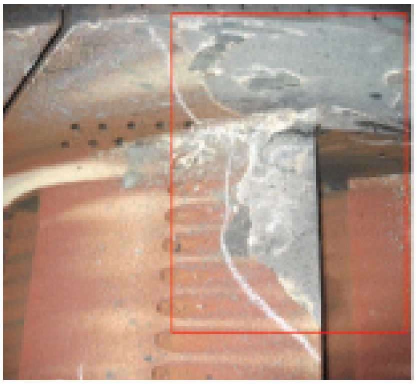
13. Lockwire is clearly out of the groove provided, compromising its ability to hold buckets in position

inside doesn't tell you everything. Consider using a fire hose; water will weep through any available opening, supporters of the idea say.

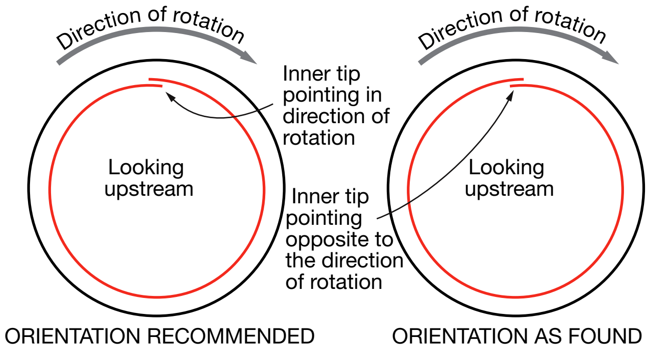
- Subject: R0 compressor blades. Everyone could get involved in this discussion. Who's back to standard blades? Who's using the latest OEM solution? Who's still running P-cuts? No consensus view.
- Pinning of rocking stator vanes and rotor clocking received plenty of air time as well. All alternative solutions discussed.
- Loose shims got significant attention. Several users reported problems with shims going through their units in the last year; several others said shim migration was revealed in borescope inspections and corrected before liberation.
- Forced-cooling philosophy generated some interest. There was general agreement that the failure rate of HRSG tubes would go up significantly if forced-cooling were imposed immediately following a GT shutdown. The solution: Wait an hour or two before starting forced cooling.
- Rotor lifetime limits imposed by the OEM continue to be a discussion catalyst. Many users still believe the limits are arbitrary and unsupported—at least to their satisfaction—by rigorous engineering analysis. One user recently told the editors during a plant visit that one of his plant's rotors with more than 5000 starts was resting on blocks waiting for the OEM to change its criteria. He believed that would happen.
- A user reported on a state-of-the-art compressor-blade health monitoring system installed on two of three 7FAs at his site with the expectation of avoiding a possible catastrophic failure. First installation was done in 2008 during a major; the second unit, in 2009. First reports had been received by the plant owner just before the meeting.

System implementation requires drilling of the compressor casing and installation of sensors to monitor blade displacement during startup; alarm is on a 40-mil deflection. User has no screen at present, monitoring is done by the OEM.

Another attendee said GE already had installed the system on six to eight machines. A question in virtually everyone's mind: Would you trust the data to the degree that you would take an engine out of service if the M&D center said to do so? There



14, 15. Fallout from the first-stage bucket migration issue includes damage to first-stage vanes and second- and third-stage buckets



16. Inner tip of the lock wire should point in the direction of rotor rotation to help prevent the lock wire from moving

is no sure answer today given the limited experience with the health monitoring system, but diagnostics in place reportedly assure that the probes are working properly and the readings are reliable.

Turbine section

High vibration that forced the shutdown of a 7FA+e engine was caused by forward migration of first-stage buckets and resultant damage (Fig 12). The unit had 788 factored starts and 17,801 factored hours at the time of the incident. Buckets were made of a coated directionally solidified, nickel-base superalloy (GTD-111).

The owner/operator's engineering team believed the bucket lock wire was able to rotate in the direction opposite to that of engine rotation, free itself from the groove (Fig 13), and wriggle out dowel pins, which went downstream (recovered from the exhaust duct).

Forward migration of a bucket cuts off its cooling-air supply and the airfoil burns. Collateral damage includes coating detachment from first-stage nozzles and melting of the base metal (Fig 14), and denting of downstream buckets by the liberated pins (Fig 15).

The thorough inspection conducted by the owner/operator revealed scratch marks between the bucket lock wire and dowel pins which were believed to have been caused by rotation of the wire. If such detail is of interest, keep in mind that 7F User Group members can access this and other user presentations at www.ge7fa.users-groups.com.

Engineers hypothesized as to why and how (1) the lock wire might rotate and (2) the dowels might work themselves free. One thought was it might be thermal expansion/contraction of the lock wire during startup and shutdown. Another was use of inappropriate dowel pins and improper overlap location when the lock wire was installed (Fig 16). Yet another thought was that the lock wire and the wheel groove were mismatched in size and the lock wire had freedom to move.

An attendee said he believed that improper installation of the lock wire and too much time on turning gear are key causes of the situation described by the presenter. Regarding the former, the owner/operator suggested others should check spare lock wire and pins against the OEM's specifications and to store them in a manner to prevent damage.

Also, before installing, check that (1) the lock wire is smoothly curved and has no sharp bends or kinks, (2) the groove is proper (use go/no-go gauge), and (3) there is no debris in the groove. Finally, review TIL-1214-3R3 regarding proper installation of dowel pins.

Turbine discussion was limited by time. The noon hour was closing in. The first bit of discussion developed around a user's concern about first-stage wheel cracking on a 7241 model. Another attendee offered that his turbine wheels had been blended/polished/peened at the first major.

He obviously considered this the right thing to do—at least until someone else in the room said, statistically speaking, you have a one-in-four chance of wheel cracking following b/p/p and only a one-in-nine chance of cracking if you don't do anything. As is often the case in open discussion forums, definitive answers/solutions are rare. However, you benefit greatly from the diversity of opinion because it opens your eyes to how others think and the many alternatives you should consider before making a decision.

Stage 3 strategy was the last topic before lunch. One user suggested changing third-stage buckets at the second HGP and retaining fit nozzles and shroud blocks for continued service.

Outage case histories

There were three case histories of outage experiences in the nearly two days of user presentations. Those three cases involved two stations, each equipped with two 2 × 1 7FA-powered combined cycles.

The combined cycles at the first station had operated for nearly 10 years and there was much work to do during the fall 2009 major inspection. The following describes key activities on the first of the two blocks at that plant. Personnel tracked lessons learned on Block 1with the belief they would facilitate work on the second 2 × 1. Everyone was encouraged to provide input and in the end 239 lessons learned were documented, one third of them for the steam turbine.

Work scope for Block 1 called for 112,000 man-hours of effort; 127,000 were required. Despite the 13% increase in man-hours, the outage budget was achieved. Actually it came in at 1% under plan. Outage duration had been planned for 43 days, but 50 were required.

Operating history of the gas-only 7FA+e gas turbines (DLN 2.6), each of which had operated for slightly more than 50,000 fired hours, included 2271 fired starts and 55 trips for GT1, and 2479 fired starts and 89 trips for GT2. Overhaul described below starts at the air inlet and proceeds through the engine to the generator. Scores of suggestions/requirements in all applicable TILs were completed during the outage.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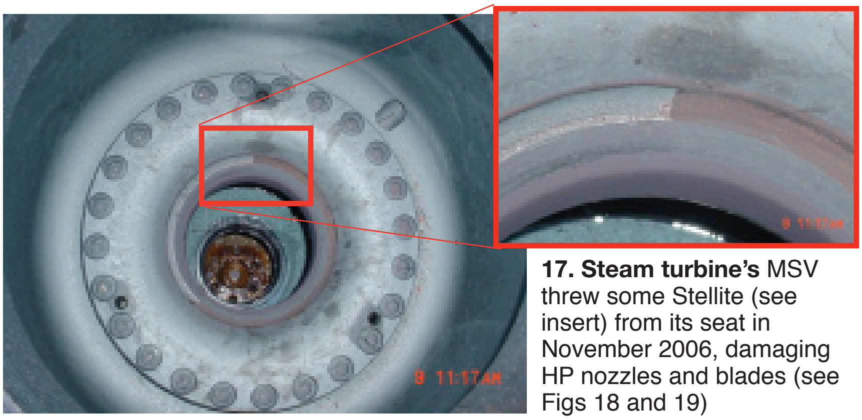
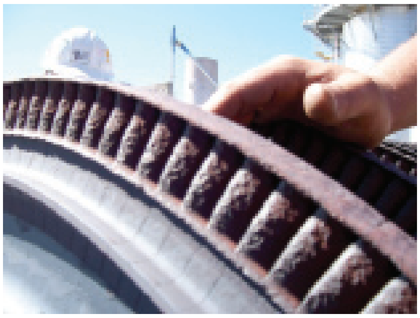


17. Steam turbine's MSV threw some Stellite (see insert) from its seat in November 2006, damaging HP nozzles and blades (see Figs 18 and 19)

18. HP nozzle block was repaired and returned to service



19. Blades in the HP section (first stage shown) were banged up badly by liberated Stellite

The air inlet houses saw little refurbishment work over their lifetimes. In fact, the air filters—standard Donaldson-type conical/cylindrical—and evap media had never been replaced. Plant personnel believe they had extracted maximum value from the air filters; when removed, the pressure drop through them was 5 in. H_2O.

After the filter houses were stripped of evap media, drift eliminators, and filters, inspectors found corrosion on parts of the support structures for those elements. The affected frames were prepped for a new coating—a two-part epoxy, Carbomastic 615HS, from Carboline Co.

The speaker mentioned that a grit blast was not acceptable for coating prep work because media could carry over into the turbine. Instead, pneumatic/mechanical needle scalers were used to remove rust from the frames. Aggressive cleanup procedures were put in place to assure that all particulate matter was removed from the inlet house prior to engine restart.

Note that the filter house is made of carbon steel, but lined with stainless from the silencers to the downward transition duct to the compressor inlet. Ductwork from the air inlet to the compressor bellmouth was carefully inspected for "opens" using daylight and water. No serious deficiencies were noted.

Rehab work complete, the drift eliminators could be reinstalled along with new evap media, and the new air filters. All seams in the evap-cooler section were sealed with Sikaflex®, the tradename for a family of one-component polyurethane adhesives, sealants, and coatings.

Gas turbines. The rotors for both gas turbines were pulled and sent to Sulzer Turbo Services' Houston shop for inspection. Several R0 compressor blades in GT1 had crack indications on their respective roots. A replacement set, supplied by the OEM, was installed at the third-party shop under the direction of the owner's engineers. Third-stage turbine parts on both rotors were evaluated by metallurgists and found suitable for continued use.

The GT2 rotor had a runout of 4.5 mils at the marriage joint. The joint was broken and the compressor and turbine rotors destacked and refurbished by Sulzer under the direction of the owner's engineers and Turbine End-User Services Inc (TEServices), a Houston-based consultant specializing in such work. To learn more about what's involved in correcting runout, visit www.ccj-online.com/archives.html, click 4Q/2009, click "Rotor overhaul. . ." on cover.

Shop time for the GT1 rotor was 14 days; that for the GT2 rotor, 21 days.

The generators for both 7241s were inspected by AGT Services Inc, Amsterdam, NY. The third-party services provider found the stator and field acceptable for continued service without wedge or rotor work and the owner's engineers concurred. The collector was resurfaced using a stationary method.

Heat recovery steam generators. Valves were the focus of the HRSG overhauls. In-situ inspections revealed extensive cracking in the high-pressure (HP) valve bodies, which was not expected. Valves were removed from their respective main steam lines, weld-repaired at a qualified shop, and welded back in place. Based on this experience, replacement valves were ordered for Block 2 and for one of the company's other plants.

All safety and relief valves were inspected, repaired, and tested for continued service. No flow-accelerated corrosion (FAC) was found in the HRSGs. Four P91 elbows were checked and one crack identified. Feedwater heater modules at the boiler stacks were CO_2 blasted to remove foreign material from tube external surfaces.

Steam turbine. In November 2006, Stellite liberated from the seat of the main stop valve (MSV) damaging the HP nozzle and the first few rows of blades in the HP turbine (Figs 17-19). The owner chose to derate the unit by 10% and operate it as is until the 2009 major.

Shop repairs regained the lost performance. The first three rows of HP blades were replaced and the remaining damage was blended with acceptable service limits. Three L-1 blades in the LP section were found with leading-edge cracks, which were an unwelcome surprise. The owner's engineers, Sulzer personnel, and third-party experts collaborated on a successful in-situ blending solution. The LP turbine work was the primary reason for the stretch-out in the outage schedule

The generator required a full rewedge by AGT Services. The collector was resurfaced in the same manner as the collectors were refurbished for the GT generators.

Other work accomplished during the major included the following:

- Condensate/feedwater system was inspected for FAC; no indications were found.
- High-energy pipe inspection. Four P91 elbows were checked by Gas Turbine Materials Associates (GTMA), San Antonio. A crack was found adjacent to a weld on one of the four elbows and repaired. A formal high-energy pipe inspection plan was put under development.

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- Cooling towers: Structural repairs, removal of sediment from the basin, replacement and calibration of blowdown control-valve actuators.
- Vibration monitoring. Replaced vibration monitoring equipment on the steamer. New system has the capability to analyze rotor stability anomalies in real time.

There were two more outage case histories presented at the meeting. Both had to do with problems identified during restarts after major overhauls. The first issue occurred while starting up one of the gas turbines at a 2 × 1 combined cycle.

The details: GT came up to FSNL as expected; unit walk-downs suggested everything was fine. The unit was auto-synched and placed in exhaust-temperature matching with a 700F setpoint for a steam-turbine cold start. At about 90 minutes into the startup (850F on the temperature-matching setpoint) the roving operator reported smoke coming from the No. 2 bearing-tunnel vent.

Unit was tripped and flames were noticed coming out of the tunnel via the lube-oil return penetration. CO_2 was discharged manually to this area.

Action taken: Unit was spin-cooled and the bearing tunnel entered by way of the outlet vent. Wires were found in good shape; however, tunnel surfaces were covered with soot. Oil was found at the bearing end of the tunnel with no evidence of its source.

All of the lower piping and control wiring were removed from the lower half of the bearing tunnel to allow removal of the arch plates lining the lower half of the tunnel. This task is particularly difficult with the unit assembled.

Once the plates were removed, the inspection team found that the lower insulation pads were saturated with oil and that free oil was trapped between the outer tunnel wall and the insulation. Investigators learned that a portable electric-power pack had been turned over by the maintenance crew and the oil ran out. Visible oil was cleaned up, but the spill was not reported to personnel responsible for managing the outage.

The entire lower half of the bearing tunnel had to be stripped, wiped down, reinsulated, and reassembled, adding three days to the outage. Lesson learned: Protect this area with plastic and oil-soak pads during the outage and establish hold points with contractors to inspect the area before reassembly.

The final case history illustrated once again the importance of *thoroughly* checking work by contractors. The abbreviated version of what happened is this: An error during re-termination of CTs to field wiring that reversed polarity on one phase permitted an uncontrolled ramp from FSNL to rated output on a freshly overhauled GT. Ramp rate was 77 MW/min, allowing the breaker to close at 154 MW in two minutes.

The OEM, which performed the major, showed little concern, according to the speaker. The unit was dispositioned to run with no further investigation. There had been no issues at the time of the presentation that could be tied back to the fast-load event. An RCA showed the wires and their terminal points were clearly marked; the I&C tech just connected the wires incorrectly and no one caught the mistake. Get the details, including wiring diagrams, at http://ge7fa.users-groups.com.

The second discussion session focused mainly on safety. Group consensus was that most injuries seem to occur on first-time events—such as lifting GT rotors, removing generator rotors, etc—where institutional knowledge on actions to be taken, and where people should be and not be, are limited.

Most also agreed that there was a general lack of expertise in the industry on rigging. It's incumbent on the plant owner, one attendee said, to assure that the contractors used—whether they be union or nonunion—have the capabilities and experience to make critical lifts. More plant training should be done in the rigging area, another user said, so staff understands what must be done and what their roles are.

Confined-space rescue and yo-yo

tie-offs also got air time—the latter especially where scaffolding is required. Two points made: You probably don't understand how difficult it is to extract a 200-lb person from a confined space until you've tried. Suggestion was made to get a 200-lb dummy and attempt it. You also probably do not know how difficult it is to handle extractions when those being rescued are combative. You never can be over-prepared where safety is involved.

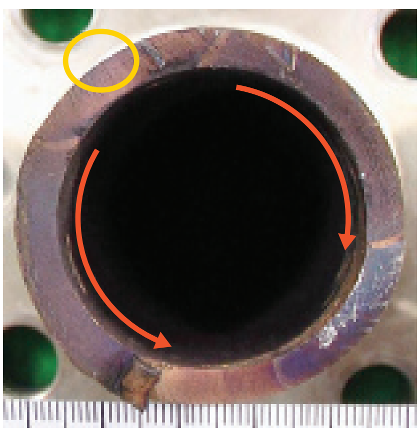
The safety give 'n take ran a solid 20 minutes and was particularly meaningful. There were many examples of what works, what doesn't, and the injuries (and deaths) that result when risks are underestimated and staff is not properly trained. You can get plenty of ideas of what to include in your plant's safety program by accessing www.ccj-online.com, click 1Q/2010, and click "Best Practices Awards, Safety" on the cover. Then go backwards in time to get even more ideas from previous first-quarter issues.

A non-safety topic in this discussion session concerned long-term service agreements, contractual service agreements, parts agreements, etc. An informal show-of-hands poll revealed that the trend away from OEM long-term agreements continues. Attendees indicated that about 40% of their agreements are now with third parties—including OEMs playing in another manufacturer's sandbox. A similar poll two years ago had third parties holding only 25% of the GT service business.

Combustion session

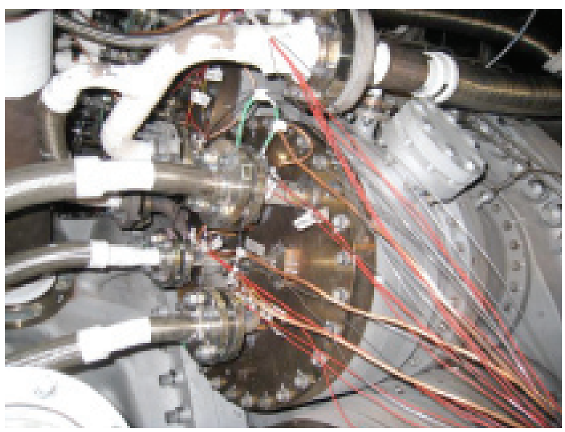
An international owner/operator with four 1 × 1 7FA+e-powered combined-cycle plants told the group about his company's experience with a fractured diffusion-air pipe on a DLN 2.6 combustor. Plant began commercial operation in April 2009 and completed its first combustion inspection in winter 2010.

A month later, just six weeks before the 7F Users Group meeting, operators received alarms of "High concentration of fuel gas" and "High temperature in the GT enclosure." Concurrently, the strength-of-flame



20. Analysis of fracture surface revealed striations characteristic of HCF along the red arrows. Starting point of the cracks appeared to be in the yellow circle at the back ends of the arrows (left)

21. Vibration sensors and strain gauges were installed on the diffusion-air pipes serving combustors Nos. 2, 8, and 12 (right)



detector for No. 12 combustor jumped from 70% to 100%. The unit was shut down immediately.

The No. 12 fuel nozzle was changed the next day. Engineers found the dummy nozzles in PM2 and PM3 melted by the radiant heat of the flame. Also, evidence of HCF was present (Fig 20). The crack initiation point (yellow circle) was analyzed using a scanning electron microscope, which revealed no significant crack, defect, and/or corrosion.

Next step was to measure the vibrations and stresses on diffusion-air pipes Nos. 2, 8, and 12 (Fig 21). Strain gages also were installed on PM1, PM2, PM3, and atomizing air pipes. Engineers found the highest strain at the starting point. Also, strain amplitudes were proportional to output power, and on combustor 12 they were larger than on the other combustors examined.

The RCA was not successful in identifying the root cause by fracture analysis. Here's what the analysis team found, and didn't find:

- Material. No material defect could be identified.
- Welding. Quality was not good.
- Acoustic vibration. There was none when the combustor was operating.
- Operational vibration. The level of stress did not exceed the material's fatigue limit, but the margin to that limit was relatively small.
- Excessive stress. Striations characteristic of HCF were found.
- Creep. There was no creep fracture.
- Stress corrosion cracking. No corrosion found.
- Low cycle fatigue. Not in evidence.

Conclusion was that poor welding and high stress attributed to vibration might have been the underlying causes of the failure. Action: Review weld quality on other combustors and improve as necessary.

Another user reported a trip on high compartment temperature. Flame burned through blanks in the combustor end cover provided for dual-fuel use. This unit had no oil capability. The speaker thought that the end cover might not have been bolted snugly. Or possibly a brazed joint might have been cracked, allowing fuel to leak into the open space. Flame "cooked" the IGV actuator line; a new actuator was installed.

An attendee said his plant had a similar incident. No root cause was offered by either of the affected parties.

Discussion moved to HGP hardware performance and interval extension. Experience at 24,000 hours was noted.

Enough can't be said about having an experienced crew patrolling the aisles with microphones to ensure that everyone can hear all questions and comments. Anyone can carry a portable microphone, but knowledgeable steering committee members with "mikes" contribute to the dialog and keep it moving. It's rare that someone on the steering committee wouldn't have had experience to contribute on any topic that comes up in a 7F meeting.

Vendor presentations

The vendor community has a great deal to offer gas-turbine owner/operators. Plant and headquarters personnel don't have all the answers, neither do the OEMs. Small businesses serving the electric power industry, in particular, are highly motivated to understand the challenges facing generation O&M personnel: Timely and effective solutions are conducive to a strong bottom line.

Most user groups sprinkle a few vendor presentations in their programs among open discussion forums and presentations by owner/operators. This organization does it differently, dedicating half a day or more to presentations on technologies, products, and services of value to 7F owner/operators.

In 2010, there were five 45-min vendor tracks with three presentations in each track. Refer back to Sidebar 3 for the complete list of vendor participants. Five tracks are planned again for 2011: two on Tuesday afternoon, three on Wednesday afternoon.

Summaries of several 2010 vendor presentations are below. Two editors can't get to all of them and, like you, have to make choices.

Modeling, simulation assist in troubleshooting HRSGs

Frank Berte, *Tetra Engineering Inc,* Simsbury, Ct
www.tetra-eng.com

Effective troubleshooting on heat-recovery steam generators is critical to assuring optimal performance of the equipment over its design lifetime. Software capable of modeling and simulating HRSG operation can help achieve these objectives. Specifically, information obtained from the simulations assists in detailed investigations of operating issues associated with a particular HRSG.

Using such software, Frank Berte told the group of about two-dozen plant personnel, process conditions in components and subassemblies where there is no instrumentation, or where it is not possible to install special test instrumentation, can be calculated to great accuracy. To achieve the level of accuracy desired, he continued, the model must precisely simulate the interaction of the gas- and water-side streams in the HRSG and other steam-system components—PID control, valves, attemperator sprays, duct burners, pumps, and steam turbines.

Each model is built using the specific plant's design information, and then is benchmarked against expected operating data. Comparison with actual operating data helps identify causes of performance shortfalls.

The model also can predict the effect on HRSG process conditions and performance (gains or losses) resulting from installation of a GT upgrade package. In certain cases, the impact of an upgrade can mean a reduction of HRSG operating lifetime and increased frequency of failures.

Simulation has been applied using relatively straightforward steady-state models to look into some common operating issues, Berte said, including the following:

- Determine local flow velocities in LP evaporator tube panels experiencing tube-wall thinning from flow-accelerated corrosion (FAC).
- Assess the potential for cold-end gas-side deposition.
- Produce input for finite-element simulations that calculate local stresses caused by thermal expansion.

Simulation output provides valuable data that are difficult or impossible to measure directly—including, local void fractions, water and steam velocities, fluid and metal temperatures, mass flow rates, heat-transfer rates, and pressure drops.

More complex models can be used to look at other issues of interest, he assured—such as verifying that temperature and pressure values remain within OEM ramp limits on startup or shutdown, or testing the effect of non-homogeneous (stratified) gas temperature and flow distributions on HRSG performance.

Dynamic simulations calculate the time-dependent parameters that affect various degradation modes in an HRSG from cycling or transient upsets. These, in turn, can be used as input to fatigue, corrosion-fatigue, and creep calculations in remaining-life assessments.

Preventing collector-ring fires

Michael Biroschak and David Cutsforth, *Cutsforth Products Inc*, Cohasset, Minn
www.cutsforth.com

"Cause and prevention of collector-ring fires in brush-type excitation systems" was well organized and easy to follow. The speakers went through their 58 slides—normally way too many for a 45-min presentation—in bullet-point fashion, letting the photos deliver the message.

A brief introduction brought the more than three-dozen users attending up to speed on the purpose of an excitation system and its basic components. Recall that a generator requires direct current (dc) to energize its magnetic field. The exciter's job is to supply that current.

Excitation current is provided to 7F generators via a collector system consisting of slip (collector) rings, brushes, brush holders, and connections to the field winding. Dc flows from the exciter, through the negative brush and slip ring, to the rotor field poles. The return path to the exciter is through the positive brush and slip ring.

Slip rings, Mike Biroschak and Dave Cutsforth told the group, typically are machined from heat-treated steel forgings that are shrunk-fit over insulation sleeves onto the main shaft. Brushes are made of graphite because of its conductive properties and excellent lubricating characteristics. The graphite film deposited on the ring minimizes the surface friction between the rotating surfaces and the brushes.

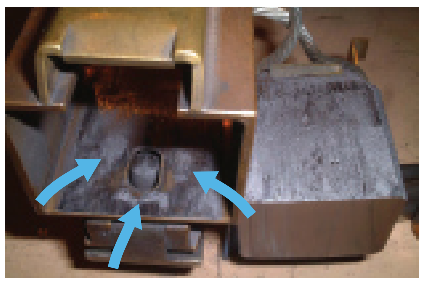
Several components comprise the brush rigging. Its purpose is to keep the brush in constant contact with the collector ring. The most important component of the rigging system is the brush holder.

Collector-ring fires were covered in detail by the speakers. Their message: Well-designed equipment and attention to detail on the part of plant O&M personnel are critical to preventing fires, which are caused by a compromised connection between the brushes and the collector ring.

One of the slides in this segment of the presentation was a particularly valuable checklist that offered 42 reasons collector-ring fires occur, by the source of the underlying problem. More specifically:

- Personnel—failure to perform daily inspections and change worn brushes, dropping conductive material into the brush area, etc.
- Methods—poor design of brush holder, improper installation of brushes and springs, etc.
- Equipment—worn leads/shunts, loss of brush contact to the ring.
- Materials—wrong brush grade, mixed brush grades, etc.
- Environment—moisture infringement, oil on holder, epoxy paints or solvents, etc.

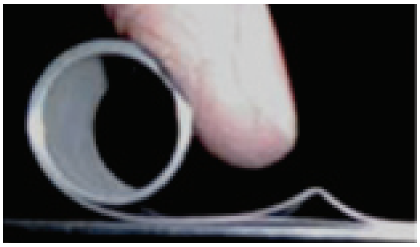
The "four most common reasons



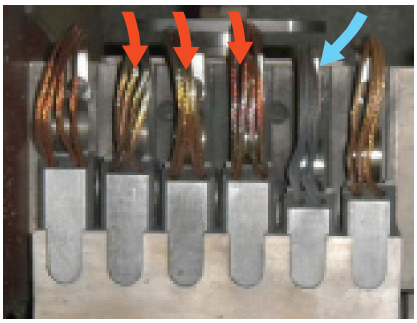
22. Carbon deposits inside the brush holder can restrict brush movement and prevent it from properly contacting the collector ring

23. Constant-pressure springs cause side pressure that results in brush binding and scoring the critical brush-to-ring connection is compromised" was of special interest to the audience, the photos providing a wake-up call to all those avoiding the doghouse area. The four reasons are:

- **Buildup of carbon deposits** on the inside of the brush holder which restrict brush movement (Fig 22). They are difficult for maintenance personnel to see and eliminate without removing the holder.
- **Brush binding.** Constant pressure springs cause side pressure which can cause a brush to bind in its holder (Fig 23). Note that carbon deposits form at the pressure points caused by brush binding.
- **Low spring pressure** caused by wear and tear, etc (Fig 24). The constant pressure of the brush-to-ring connection is compromised, initiating arcing.
- **Poor terminal connections** are conducive to "selective-action," a term that describes what happens when the normal action of the current switching from brush to brush seeks a path of least resistance (Fig 25). It causes leads on one or two brushes in the circuit to turn very hot, preventing them from carrying current.



24. Spring wear and tear (note kink under finger) compromises proper brush-to-ring contact pressure



25. Lead discoloration (red arrows) and selective action (blue arrow) are in evidence above. Latter is no longer capable of carrying current

26. Aftermath of a flashover. Brushbox carbon deposits compromised brush-to-ring connections and caused arcing, which escalated into a serious fire

Compromised brush-to-ring connections are conducive to flashovers, which can be scary (Fig 26). Here's the sequence of events leading to a flashover: A compromised connection causes an imbalance of current flow within the circuit which leads to selective action in one or more brushes.

The brushes having good contact "drop out" because the current-carrying capacities of their leads are exceeded. The remaining brushes in the circuit become overloaded and arcing typically occurs where brush-to-ring connections are poor. Arcing ionizes the air, creating ozone. Increased current and high resistance generate heat.

Next, arcing begins to damage and melt the brush holders and air blowing on the molten metal creates a plasma-torch effect. This, in turn, greatly reduces the normal insulation value of air which adds more flashover possibilities.

Ways to minimize flashover risk closed out the presentation. Increased maintenance was at the top of the list (remove carbon deposits, replace springs regularly, check for brush binding, refurbish holders, etc). Measuring brush amp readings regularly to help identify selective action and holders that need attention or maintenance was the second point. Final point, and the closest the speakers got to a "sales pitch," was the suggestion to upgrade to a proven and well-designed holder—Cutsforth's obviously.

Water cooling improves reliability of fuel valves

Schuyler McElrath, *JASC-Jansen's Aircraft Systems Controls Inc,* Tempe, Ariz
www.jasc-controls.com

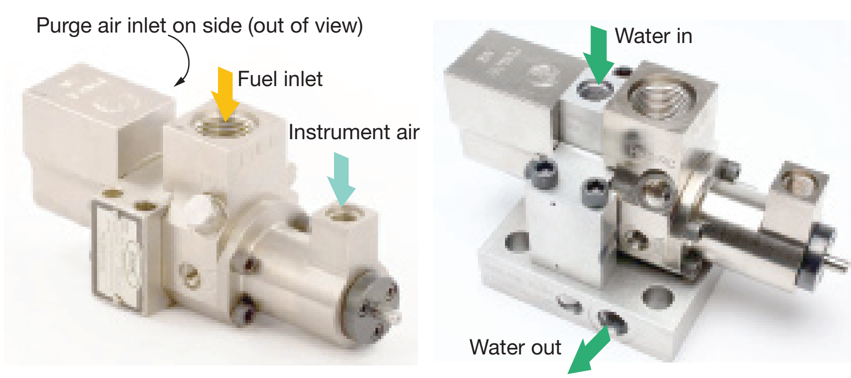
It wasn't long ago that some owner/operators were disabling or removing liquid-fuel systems from their dual-fuel gas turbines. Primary reason: There was no need to burn oil, which was more expensive than gas, and the superfluous system added to the complexity and cost of annual inspections.

Plus, the typical monthly tests on liquid fuel often were stressful because coking problems, caused by the "cooking" of small amounts of distillate remaining in the system components when the engine operated on gas, inhibited fuel transfers.

Fast forward to today: Development of a robust ancillary services market to support the integration of renewable resources with conventional generation is forcing some owners to convert gas-only turbines to dual fuel (see special report on integrating renewables elsewhere in this issue). Grid companies are reluctant to write contracts for "must-run" engines unless they are dual-fuel capable and can prove it.

Also, reliability concerns have municipals and cooperatives specifying dual fuel for new units and improving the functionality of liquid fuel systems on existing engines—this to assure native load doesn't go dark in the unlikely event gas supply is interrupted. Recall that public power companies are owned by their customers, most of whom are voters.

Owner/operators attend user-group meetings to keep up with technology developments and to learn from the experiences of others. Last thing you want to do is to make the same mistake a colleague had made previously.



27. 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)

Schuyler McElrath's goal at the 7F meeting was to make users aware they could improve the reliability of their liquid fuel systems by implementing JASC solutions—including water-cooled liquid-fuel check valves and three-way purge valves.

The company, a high-tech, fluid-flow solutions provider for the aerospace industry, combined its engineering prowess and past experience to produce a suite of products that McElrath said has back-up liquid fuel systems operating on large gas turbines at better than 98% reliability and availability industry-wide.

Performance of the water-cooled liquid-fuel check valves installed on more than 100 engines has been particularly impressive—near 100% reliability on oil starts and on transfers from gas to oil. The valve is approved by the OEM for use on GE engines.

McElrath began his presentation with a backgrounder on the causes of coking and the problems it causes. Then, using a series of simplified P&IDs for both standard and DLN combustion systems, he showed the gathering of about three-dozen plant personnel how JASC valves are designed as drop-in replacements for old style valves. After swapping valves, McElrath continued, all you have to do is hook up cooling water. It only takes a weekend to upgrade to a highly reliable liquid-fuel system, he assured.

Cooling-water requirements are modest. Example: 7 gpm or less is all that's required to cool the 28 liquid-fuel check valves on a 7FA (one valve each in the primary and secondary fuel circuits serving the engine's 14 combustors). Cooling-water lines can be run with the engine in operation and the tie-ins made on the weekend.

Once McElrath had the group sold on the competitive advantage JASC offered GT owners, he got into the nitty-gritty of valve design and then showed the users how they could reduce costs by converting existing three-way purge valves to water cooling for one-third the cost of buying new valves (Fig 27).

Easiest way to track the development of JASC technology for dual-fuel land-based frame engines, and implementation experience, might be to access www.ccj-online.com/archives.html and read these three articles: 3Q/2006, click Outage Handbook at the bottom of the cover, click "GT fuel-system enhancements. . ."; 3Q/2009, click "7F Users Group," scroll to p 20; 2Q/2010, click "Improve reliability of gas turbines on liquid fuels."

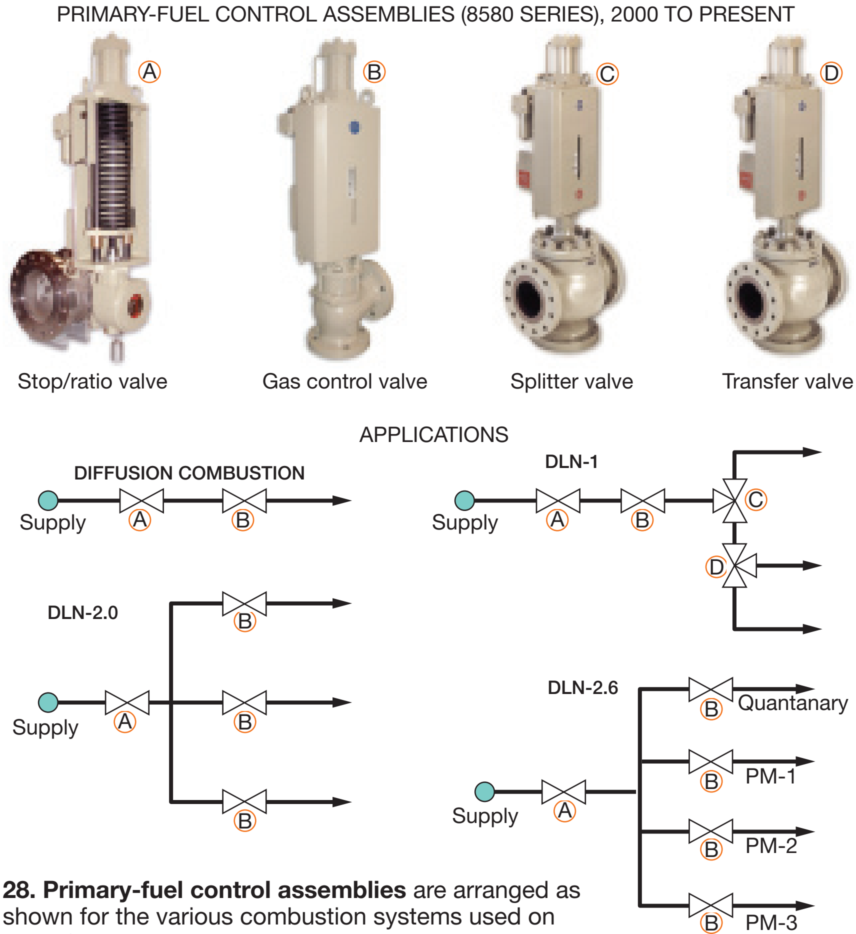
The evolution of primary-fuel control assemblies

Chris Yeckel, *Young & Franklin Inc*, Liverpool, NY
www.wf.com

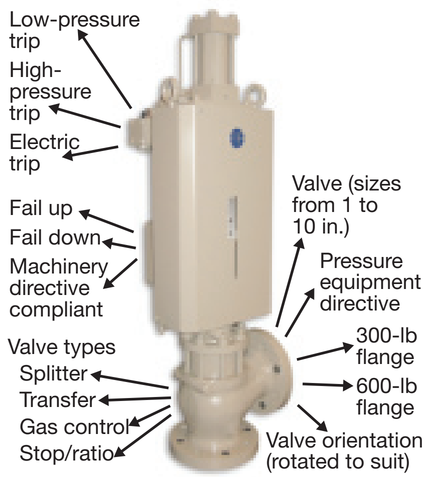
In the world of fluid controls for turbines, the Young & Franklin name stands as tall as the manufacturers it serves. For more than half a century, OEMs such as GE Energy, Solar Turbines Inc, and Pratt & Whitney have installed Y&F products on more than 10,000 land-based gas turbines worldwide. In the last decade, the company has applied its technical expertise to precision controls for steam turbines.

Product reliability is perhaps the key reason for the company's success. To illustrate: A recent article profiled a pair of Frame 3s owned and operated by Montana Dakota Utilities still operating today—55 years after COD—with the same Y&F fuel regulators provided with the unit. First servicing of those regulators was done more than 50 years after first fire (access www.ccj-online.com/archives.html, click 2Q/2009, click "Gas Turbine Historical Society" on the cover).

Chris Yeckel, a Y&F senior project engineer, began his presentation with a review of the various primary-



28. Primary-fuel control assemblies are arranged as shown for the various combustion systems used on large GE frames



29. Series 8580 primary-fuel control assemblies features one basic actuator body; each assembly is tweaked for each modification/variation

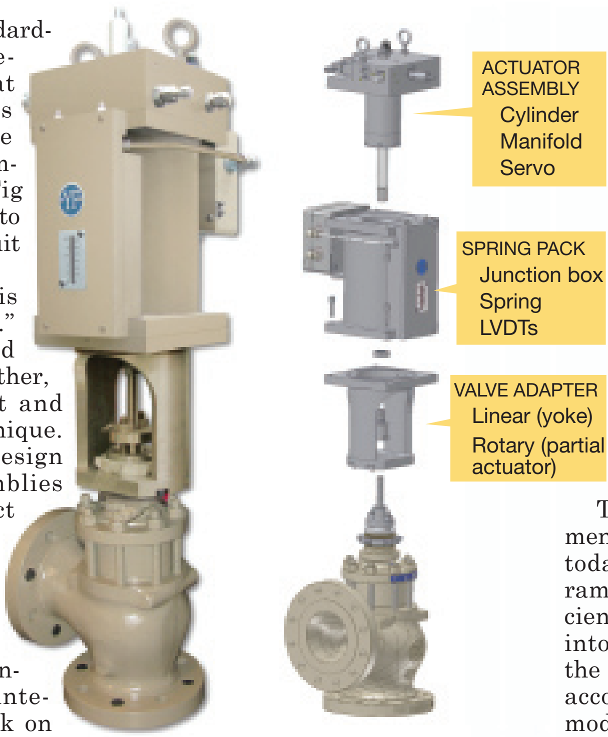
fuel control assemblies the more than three-dozen user attendees have on their gas turbines. While the products covered dated back to combined valves first applied in 1960, Yeckel's talk focused on the 8580 series of stop/ratio, gas control, splitter, and transfer valves introduced in 2000 (Fig 28) and new products under development.

The 8580 family relies on one basic actuator body to serve a wide range of valve applications, as shown in Fig 29. While such "standardization" has obvious benefits, the bottom line is that Y&F's product line really is "mass customization." There are more than 900 part numbers associated with the Fig 29 assembly, allowing Y&F to supply the exact valve to suit any given requirement.

This means each valve is built from the "ground up." Because cylinder size and spring force depend on each other, as well as on valve height and stroke, each assembly is unique. However, the integrated design does have a few subassemblies which enable faster product assembly and reduce delivery lead times to the minimum possible.

The 8580 product line presents some customer challenges as well, Yeckel continued. For example, the integrated design prevents work on the actuator while the valve is in-line. Users also are restricted on the type of field maintenance they can perform: Except for servo and filter, there are few field-serviceable parts. Plus, special tools and extreme caution are required for decompressing the spring.

To address these and other issues,



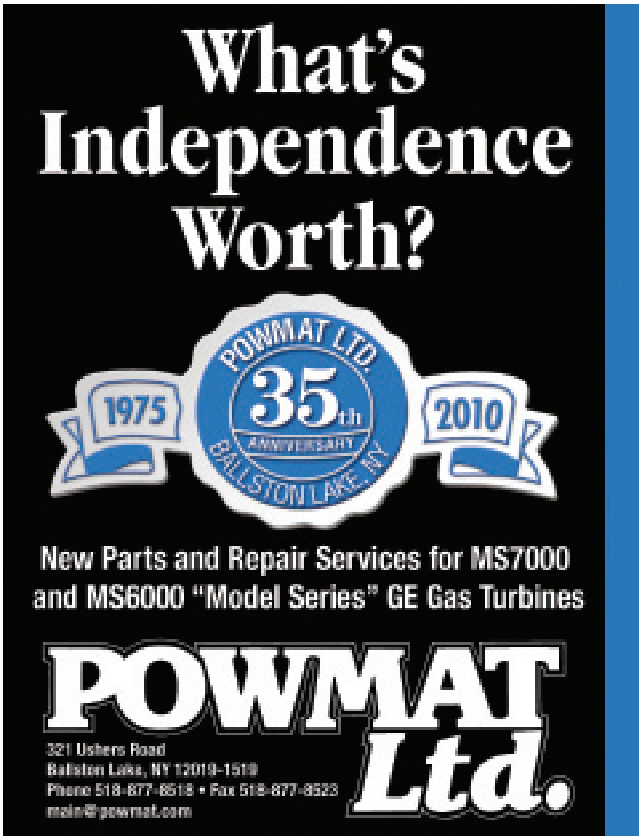
30. New generation of modular, ruggedized valve actuators under development offers design simplicity, high reliability, field serviceability

Yeckel said, Y&F is developing a new generation of modular, ruggedized valve actuators. One of the first actions on the project was brainstorming to decide which valve functions must be isolated, which can go together. The modular actuator shown in Fig 30 shows what the company has in mind.

There is a modular valve offering as well. Standard valves for natural-gas fuel control are 1, 2, 3, 4, and 6 in. and are direct replacements for Fisher EAB fuel control valves. The Y&F valves, suitable for all GE frames (3, 5, 6, 7, and 9), are of the balanced-low-force type, right angle, 300-lb flange. Specifications: ANSI B16.34, FCI 70.2 leakage, Class IV.

The more demanding requirements being placed on gas turbines today—including faster starts and ramps, lower emissions, higher efficiency, top reliability—are factored into the new design. For example, the actuator has been ruggedized to accommodate the more aggressive modulation (dither) required. This is evident in the fine-tuning of misalignment-coupling location, changes to bearing surfaces, and upgrading of engineered seals and wear surfaces. Plus, all seals are field replaceable.

Progress report: Yeckel told the 2010 7F attendees that Y&F's next-generation, all-electric fuel controls for gas-fired turbines were in beta



tests on a 7FA+e and that the company was looking forward to sharing test results with the group at the 2011 meeting in Houston.

Automating asset management

Thomas Christiansen, *Strategic Power Systems Inc,* Charlotte, NC
www.spsinc.com

Today's competitive generation market dictates aggressive asset management to assure profitability. Houston-based Direct Energy LP is one company focused on achieving and delivering measurable "best in class" performance across its Texas fleet of three 7FA-powered 2 × 1 combined cycles—Bastrop, Frontera, and Paris Energy Centers.

Senior VP Thomas Christiansen told the breakout session that Direct Energy had specific requirements regarding the standardization of data collection and reporting. Essential to the company's business were standard plant and portfolio reports (weekly, monthly, quarterly, annual) and critical HGP parts-life tracking.

The company considered as critical the visibility and transparency of objective information across the enterprise; also, that data collection and reporting be executed in a secure manner to assure compliance with NERC CIP standards.

Collection of the required data was the first challenge, Christiansen said. It was important to have all three plants analyzing and reporting consistent metrics. May sound simple, but given the plants' varied historical ownership and use of different Microsoft Excel spreadsheets, it was not.

Working together, SPS and Direct Energy established a Strategic Information Architecture (SIA) process for the fleet. It relies on SPS's ORAP™ family of products and services—including ORAP Link, Parts Tracking, and Fleet Reporting, plus Base ORAP, to collect data from the DCS at each plant once per second. Note that data collection is accomplished virtually without human effort. The only input required from plant staff is detail on "events," which only knowledgeable plant personnel can provide.

SIA then converts the data into production-related metrics: time, capacity (or energy), and events, using logic developed by SPS. Next, a mission profile specific to each unit is developed—from startup to shutdown. It includes all pertinent information. Finally, data are uploaded to the ORAP database for engineering validation by SPS personnel and then made available for reporting through the ORAP web portal.

Value proposition. Prior to SIA implementation, Direct Energy estimated that it took eight hours per plant per week to collect and report the RAM information alone. Most of this information now is collected automatically and requires little input to produce weekly reports on-demand. SIA has been accepted, and is used regularly by engineering, finance, and operations personnel regularly.

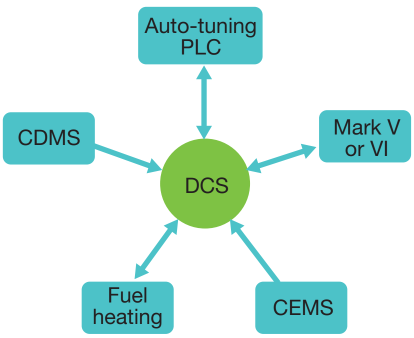
Optimizing gas turbine operation

Marcus Turner, *Gas Turbine Efficiency,* Orlando, Fla
www.gtefficiency.com

Plant personnel responsible for gas turbines equipped with dry, low NO_x (DLN) combustion systems sometimes are faced with variable operating conditions that challenge their ability to achieve reliability, efficiency, and profitability goals.

Recall that the lean flames required to keep NO_x emissions low are conducive to dynamic instabilities. Known as combustion dynamics, the instabilities can damage hot-gas-path components. Combustion dynamics monitoring systems (CDMS) were developed to prevent such damage by warning of impending trouble.

These systems also are able to identify changes in dynamics associated with hardware failure, thereby allowing users to pinpoint combustor issues and to take action before addi-



31. CDM system continuously monitors combustion dynamics and relays this information to the DCS, which monitors emissions and sends data to the auto-tuning PLC. The PLC determines when adjustments are necessary and automatically tunes the turbine to the operator's optimization goals.

tional damage or failures can occur.

ECOMAX™ was developed by GTE to take the "uncertainties" out of DLN operation by providing users an automated, fully customizable solution to achieve their objectives regarding dynamics, emissions, and power. A CDM system is a key part of Ecomax, providing real-time monitoring of dynamics, and allowing for real-time tuning.

The auto-tuning component of Ecomax enables plant personnel to fully customize operating objectives. With customized pre-set parameters, the operator can choose from among optimal NO_x, power, and dynamics. Pre-set on/off switches allow for easy and immediate switching among operating modes.

Thus, the plant operator determines a specific objective for a given time or set of circumstances, all the while maintaining his or her ability to switch turbine settings to achieve another objective quickly and immediately (Fig 31).

GTE Tru-Curve permits adjustments in the firing curve to optimize turbine output safely, once a CDMS and auto-tuning are installed. The latter acts as a safety measure against sudden changes that can cause dynamics or emissions excursions when operating at higher-output firing curves. Maximizing turbine capacity, of course, increases revenue for a proven capacity, all within OEM firing guidelines.

Metallurgical analysis: It's role in GT maintenance

John Bottoms, *Liburdi Turbine Services Inc,* Mooresville, NC
www.liburdi.com

John Bottoms had 34 slides, not excessive for a 45-min presentation, depending on how much time you want to allow for Q&A. But those slides had lots of detail, including a healthy dose of photomicrographs to explain component deterioration that occurs during gas-turbine operation and why you don't want to think about extending maintenance intervals unless you have good understanding of the metallurgy involved.

The presentation focused on component deterioration, covering base alloys, external coatings, surface condition, as well as internal surfaces. He then showed the 30 or so owner/operators in attendance how to use the findings of metallurgical assessments to better manage risk and make better repair decisions.

Certainly too much technology to summarize in meaningful fashion here, so the editors decided to compile Bottoms' subject matter into a full-length feature for the next issue.

Flame scanner needs no liquid cooling

Hank Marsman, *BFI Automation USA LLC,* Bridgewater, NJ
www.bfi-automation.com

Hank Marsman's message to the 7F users was simple enough: BFI Automation adapted its fiberoptic flame monitoring technology for GE Frames 5, 6B, 7EA, 7F, and 9 running virtually any of the OEM's control systems—including Mark IV, V, and VI. Pulse, relay, and 4-20 mA are user-selectable.

The sales point was that liquid cooling turns the flame-scanner sight tube into a condenser during startup, creating water droplets on the sensor lens which refract UV radiation and can cause nuisance trips. Marsman added that GE Technical Information Letter 1579 R1 raises additional concerns of potential damage to the turbine from leaking coolant.

Conversion from a liquid-cooled scanner to a fiberoptic one is easy, Marsman told the group. Simply remove the existing UV tube or silicon carbide sensor and all related coolant tubing, capping it off. Then screw the fiberoptic probe—basically a glass eyeball inside a stainless steel fitting—onto the sight port.

Mount the electronics box, which includes the sensor, in a remote location away from turbine heat and vibration. Use an armored fiberoptic cable to connect the probe to the electronics box; connect all the wires.

The self-checking flame scanner is designed fail-safe. Performance can be data-logged and trended. Marsman made a point of the system being repairable, not an expensive throw-away. In the unlikely event the system fails, he added, it can be replaced with the turbine in operation.

CRV Plate protects against varnish

Hans Overgaag, *AnsaldoThomassen,* Rheden, The Netherlands
US contact: Cary Forgeron, Analysts Inc
www.analystsinc.com

Hans Overgaag, one of the developers of the Cross Relief Valve (commonly referred to as the CRV Plate), came from Europe to explain how this device virtually eliminates varnish from critical servo-valve components. Simply put, it ensures a continuous flow of oil through the valve independent from control-system settings and commands, but without interfering with the servo's control functions.

Readers are referred to "CRV Plate helps protect servo-valve components against varnish," available at www.ccj-online.com/archives.html, click 1Q/2010, click article name.

PAG: Alternative to mineral oils

Dr Govind Khemchandani, *Dow Chemical Co,* Freeport, Tex
www.americanchemtech.com

The focus of Govind Khemchandani's presentation was the advantages of non-varnishing polyalkylene glycol (PAG) synthetic turbine fluid over mineral oils in high-temperature GT service. You may recall that the Dow Chemical formulation is marketed as EcoSafe® TF-25 in North America by American Chemical Technologies Inc, Fowlerville, Mich.

This subject was covered in the COMBINED CYCLE Journal most recently in the 3Q/2009 issue. The article, which is integrated into the 2009 7F Users Group report (p 18), contains much of the information most users would require for decision-making—including two case histories. Access the article at www.ccj-online.com/archives.html.

More technical detail is available in a paper by Khemchandani, "Tribological characteristics of PAG-based synthetic turbine fluid." To obtain a copy, write Kevin Kovanda, president of ACT, at kkovanda@americanchemtech.com.

CDM uses fiberoptic transducers

Rick Lopushansky, *Davidson Instruments,* The Woodlands, Tex
www.davidson-instruments.com

Rick Lopushansky introduced the 7F users in his session to Davidson Instruments' temperature-tolerant (up to 1000F on a continuous basis) fiberoptic-based pressure transducers for monitoring combustion dynamics. He said the transducers are designed for mounting directly on the turbine casing of 7FA as well as inside the J-tube of Siemens 501 engines without the need for engine mods. Lopushansky added that the product had passed 7FA field tests.

For the 7FA, the transducer projects through the casing and is positioned flush with the inner liner in close proximity to the combustion zone. The device has a flexible tip to prevent damage caused by misalignment of the holes in the casing and the liner. Cooling is by way of the 800F air circulating between the casing and liner.

Use of fiberoptics eliminates the need for the acoustic tubes, purging systems, electronic transducers, and charge amplifiers found on most other systems, Lopushansky continued. The signal conditioner can be configured to provide either an analog or digital output and is compatible with conventional spectrum analyzers and CDMS monitoring software.

Output of the CDMS can be displayed on a monitor showing separate alarm thresholds for cold, hot, and screech tones. The combustion dynamics signals also can be monitored remotely via the Internet, allowing experts to review results using predictive-maintenance and special diagnostic algorithms.

Control-valve repair solutions

Andy and Steven Balough, *Megawatt Machine Services,* Somerset, NJ
www.megawattmachine.com

The Balough brothers had a timely message for 7F owner/operators who had heard only two days earlier about the failure of a main-stop-valve seat, and the downstream damage it caused, from a colleague presenting on a steam-turbine major (p 36, Fig 17).

Frequent cycling causes valve trim to wear prematurely. The duo suggested that users consider upgrading material specs for trim when specifying new valves and when shop visits are necessary for repairs—particularly if you're seeing the same problem a second or third time. They discussed base-metal upgrades, heat treatments, and hard coatings and overlays.

One of the problems owner/operators sometimes face is that they don't know their high-energy valves are in need of repair until they are opened and inspected during an outage. If new trim is needed, ordering from the OEM can be expensive and delivery times long.

A third-party shop might have the solution you need to meet schedule requirements at a competitive price. But thorough due diligence on shop capabilities and performance is critical. You might want to think about doing this while in the outage planning phase, in case you need such services.

The Baloughs suggested you ask candidate vendors to provide their QA/QC manuals with ISO9001 certification. Plus provide a list of shop equipment available to perform the repairs you might need.

Critical capabilities for third-party shops, they continued, include the following:

- Reverse engineer trim to OEM specifications both in the shop and at the plant site.
- Provide both hard parts and soft goods.
- Perform all tests (alloy analysis, hardness, etc) and inspections required.
- Field service—including open and inspect valves, repair in place (including machining if required), close, stroke, and calibrate AOVs and MOVs. CCJ

It happens every spring

No, this is not about the fictional baseball movie starring Ray Milland and Ed Begley, but rather the annual meeting of the Western Turbine Users Inc (WTUI), held just in time to prepare you and your colleagues for upcoming spring outages. Owner/operators of LM2500s, LM5000s, LM6000s, and LMS100s don't want to miss this opportunity to get the latest information on what to look for during engine inspections and how to better plan overhauls.

The group's 21st annual conference and exhibition will be held at the Renaissance Palm Springs Hotel and the adjoining Palm Springs Convention Center, March 20 through March 23. Note that the recently remodeled Renaissance previously was known as the Wyndham Palm Springs—the same venue as the 2009 meeting.

Among the various user groups serving the gas-turbine-based powerplant sector, Western Turbine offers, perhaps, the most thorough learning experience. Each engine has its own series of breakout sessions—typically five—totaling more than eight hours of rigorous presentations and group discussions.

The presentations are well planned by the group's steering committee (Sidebar 1) working collaboratively with the five OEM-licensed depots that perform most of the engine overhauls: TransCanada Turbines (TCT), Calgary; MTU Maintenance Berlin-Brandenburg GmbH, Ludwigsfelde, Germany; Air New Zealand Gas Turbines (ANZ), Auckland; Avio SpA, Rivalta di Torno, Italy; and IHI Corp, Tokyo, Japan.

In terms of deliverables, no user group in this industry sector compares to Western Turbine. Each registered user receives a notebook which may have 100 slides—sometimes more—developed by the depots for the breakout session you have selected. A typical depot notebook contains the following material:

- Engine fleet statistics, manuals, and definitions.
- A review of recent service bulletins and service letters issued by the OEM.
- A summary of depot findings since the last meeting. This information is invaluable for anyone planning an outage.
- Causes of performance loss and how to correct them.
- Critical parts-life management.
- Engine preservation, handling, and transportation.
- Expectations with regard to maintenance intervals.

Session book in hand, it's easy to follow the presentations and jot down additional notes where necessary. And if you step out of the room to take an important call, WTUI has you covered. President/CEO Sal DellaVilla and his colleagues at Strategic Power Systems Inc, Charlotte, attend every session to take notes which then are posted in the user-only portion of www.wtui.com.

SPS's notes form the basis for the summaries of the 2010 breakout sessions included here. Other aspects of the 20th anniversary meeting,

1. Western Turbine officers, directors

President: Jon Kimble, *Wellhead Services Inc*

Vice Presidents:
Bill Lewis, *PPL Edgewood Energy*
Jim Bloomquist, *Chevron USA Inc*

Secretary: Chuck Casey, *City of Riverside*

Treasurer: Wayne Kawamoto, *CAMS Juniper CA LLC, Corona Cogen*

Directors:
Mark Breen, *Wood Group Power Operations Inc*
Alvin Boyd, *City of Pasadena*
David Merritt, *Kings River Conservation District*
Tony Skonhovd, *Basin Electric Power Cooperative, Groton Generation Station*
Don Haines, *Wood Group Power Operations Inc, Panoche Energy Center*
John Baker, *Calpine Corp, Bethpage Energy Center*
Bradley Hans, *PE, Lincoln Electric System, Terry Bundy Generating Station*

Technical Consultant:
Mike Raaker, *Raaker Services LLC*

Breakout Chairs:
LM2500. John Baker, *Calpine Corp, Bethpage Energy Center*
LM5000. Chuck Toulou, *Ripon Cogeneration LLC*
LM6000. Bryan Atkisson, *City of Riverside*
David Merritt, *Kings River Conservation District*
LMS100. Don Haines, *Wood Group Power Operations Inc, Panoche Energy Center*

Supporting Members:
Wayne Feragen, *webmaster, E I Colton LLC*
Joella Hopkins, *conference director, Simply Mumtaz Events Inc*
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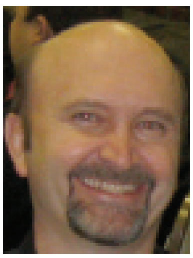
2. Acronyms to remember

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

held last March in San Diego, were covered in the 1Q/2010 issue, which can be accessed at www.ccj-online.com.

Conference plan


Kimble

WTUI President Jon Kimble of Wellhead Services Inc told the editors in December that the 2011 conference program would be similar in arrangement to last year's. The conference will officially start on Monday morning and run until noon Wednesday. Unofficially, the event begins early Sunday morning when the gofers tee off for the annual Western Turbine tournament. Tennis competition is scheduled to start around noon.

WTUI conducts one or more orientation sessions for newcomers; these are held after Sunday's sporting events. The LM engine familiarization workshop, which runs for about an hour and a half in the late afternoon, always gets high marks from newcomers. Typically, one-third to one-half of the user attendees at the annual meeting are first-timers, many unfamiliar with one or more engines supported by the group. The crash course is excellent preparation for the breakout sessions beginning Monday morning.

Almost certainly, newcomers find themselves lost in the alphabet soup of acronyms this group uses in casual discussion (Sidebar 2). Morse code might be easier to understand.

Tuesday afternoon typically is reserved for one last visit to the exhibit hall and special technical presentations by industry consultants and equipment suppliers. Topics are carefully selected by the WTUI officers and board of directors. Program details are published on www.wtui.com as they become available.

Kimble reminded that the group's mission is to provide a forum for the exchange of technical, operations, and maintenance information and experience, with the goal of improving the reliability and profitability of generating facilities using GE aeros.

LM-engine users who have never attended a WTUI conference probably cannot imagine the value associated with participation. It is the rare attendee who returns to his or her plant without an idea for saving several thousand dollars in maintenance and/or operations. Comradery is a defining characteristic of this group, enabling the helpful exchange among delegates.

Engine breakout sessions

LM2500

Session chair and discussion leader for the LM2500 breakout sessions was John Baker, O&M manager for Calpine Corp's Bethpage Energy Center, Hicksville, NY. The depot presentation was led by John Leedom of ANZ, with support from MTU's Nico Brademann, TCT's Kevin Singh, and Avio's Antonio Errico.

Leedom began by reviewing the agenda and then moved through talking points on fleet operating status and recent service bulletins (SB) and service letters (SL) applicable to the LM2500.

Fleet operating experience continues to grow at a rapid pace because of the LM2500's popularity, particularly in marine applications. According to the OEM's numbers (March 2010), 1388 engines have been installed worldwide, 150 of those in the US for stationary power-generation applications.

Industry consultant Mark Axford, Axford Turbine Consultants LLC, Houston, confirmed the number, adding that nearly one-third of those land-based engines had been delivered to California job sites between Jan 1, 1980 and Dec 31, 2009, with about 40 still in service.

Well over 1000 LM2500s are operating on a variety of cruisers, frigates, destroyers, and patrol boats for

30 or more international navies. The engine also has been installed on fast ferries, supply ships, cruise ships, etc. Plus, it serves as the prime mover for some compressor sets and is popular for trailer-mounted mobile power applications.

Capabilities. An important point for owner/operators to remember is that all depots do not service all engines and all do not offer the same level of service for each engine type. Specifics are available at www.ccj-online.com/archives.html, click 2Q/2008, click "Western Turbine Users" on the cover and scroll to p 54. This information is two years old and should be confirmed. An update of depot activities appears in the Western Turbine section of 1Q/2010, also available online.

Keep in mind that not all SBs pertain to every engine. Users should carefully review each publication and determine its applicability for their machines. Note, too, that the OEM no longer mails hard copies of the SBs to owner/operators. They are posted on the GE website in a protected area. Registration is necessary for access.

The notes that follow begin at the compressor front frame and summarize the highlights of the presentations/discussions in Baker's sessions. For more detail, access the depot slides posted in the user area of www.wtui.com.

Compressor front frame (CFF). No. 3 bearing oil seal was one of the first subjects discussed, as it was last year (click 3Q/2009 on the CCJ archives index, click WTUI on the magazine cover and scroll to p 44). Depots reported receiving many engines with "ballooned" seals; they suggest the implementing the recommendations of SB 205 Rev 1 which allows repair of the Teflon seal.


Baker

An indication of this condition is excessive oil consumption and Teflon in the lube and scavenge-oil filter. If the seal fails, the speaker strongly recommended removing all Teflon debris from the TGB and AGB (Sidebar 2 offers an index of acronyms).

Inlet gearbox (IGB). Inner-race migration was another carry-over discussion point from last year. It is identified by unusual wear patterns on the gear teeth and difficulty rotating the IGB. The depot reps said this condition is found on a couple of engines annually.

Horizontal gear-shaft spline wear was discussed again as well. Attendees were referred to the ruggedized oil nozzle described in SB 160 and the spline adapter with extra drain holes in SB 199 as solutions for facilitating oil flow the length of the spline.

A user asked if the IGB is part of the overhaul process. Answer: Yes. The teeth and housing are stripped and recoated and the carbon seals and main line bearings inspected/replaced as required.

HP compressor rotor (HPCR). Two engines equipped for inlet fogging were received by one depot for maintenance. Most of the HPC blades suffered erosion; two blades liberated after approximately 10,000 hours and caused extensive downstream damage to the compressor, combustor, and HPT. First assumption was than an inlet-damper failure caused the damage.

Widespread erosion was identified after the blades were removed. Lab analysis showed cracks initiated at the eroded leading edges of the blades, with the most severe cracking found on the IGV and first-stage airfoils. A homemade inlet fogging system was pinpointed as the root cause of the failure.

A few instances of 16th stage HPC platform cracking and/or liberation were reported by a depot. The failures occurred on LM2500+ engines where both SB161 and 162 had been performed. Attendees were advised to implement 161/162 on "plus" engines and SB 180 on base units because this damage mechanism can appear quickly. Another recommendation: NDE (nondestructive examination) 16th stage blades whenever access is available.

HP compressor stator (HPCS). VSV system wear received a few minutes of "air" time. The depots recommended replacement of any actuation arms with bends in excess of 4 deg. Reason: Air flow disturbances that might occur are conducive to high cycle fatigue (HCF), which can lead to blade failure/liberation. Periodic inspection of VSVs and external cleaning (especially under the bridge connector) were recommended. A user suggested using a gauge to measure lever-arm angles rather than the human eye.

Question from the floor: What operational abnormalities might be observed when the pins are worn? Depot's answer: If pins are worn badly enough, a stall condition is possible. An attendee in the user-only session commented that he did not think any change would be noticed before a catastrophic failure occurred.

Compressor rear frame (CRF). The bad news: Depots reported increasing instances of mid-flange damage. The good news: CRF cracking is far more prevalent on marine engines than on stationary turbines in power-generation service. Important to note is that the repair procedure for welding cracks is no longer acceptable; rather, the CRF must be replaced. Suggestion to users: Check bolts for proper torque when practicable.

The cause of CRF cracking is HCF, which occurs because of alternating stresses in the bolt holes. The stresses are highest in engines running between 7000 and 8000 rpm, which is where most marine turbines operate.

DLE combustor. Heat shields of the old design are experiencing burning. Cutting back the shield seems to solve the burning problem. One depot reported hearing that the OEM was developing new heat shields. The OEM said the +G4 engines featured a bolted heat-shield design, but the base and +DLE engines did not; also, there were no immediate plans to switch to a bolted design.

A question from the floor had to do with conflicting information regarding the use of a TBC coating on the G79 combustor. The OEM said it shouldn't cause any problems.

HP turbine, second-stage nozzle assembly. Depots reported a couple of incidences of outer air seal bolt damage, which is repairable. Cause was use of incorrect bolts during an HPT module exchange. Depots suggested that users verify parts numbers before installation and check the length of bolts.

Users were urged to check cooling-air tubes for wear, which can cause turning of the tubes and reduced air flow. This issue has been known for some time; there were no new developments to report.

HP turbine rotor (HPTR). First-stage buckets should be replaced as a set, users were told. Bucket numbers G03 and G01 should not be mixed. The latter are prone to failure because there's insufficient cooling air to cavity 8. Regarding damper seals, depots are replacing them at 50,000 hours regardless of visual condition and wear. Replacement at 50K is less expensive than the repairs required if damper seals were to fail.

Turbine mid frame (TMF). The depots recommended that liners be inspected periodically for bulg-

ing, especially on units where CDP steam is used without baffles. Aft flange cracking was another discussion point. High temperatures in the package and excessive engine vibration were identified with the unit where the cracking occurred. The flange was replaced but the root cause never identified.

Turbine rear frame (TRF). Relatively few TRF failures have been reported aside from some instances of frame cracking. One depot reported that it is applying antifriction tape on clamps where metal-to-metal contact exists. Reduced wear is the result. Users were told that tape should not be applied unless parts are as-new. Tape does not inhibit clamp movement.

Handling, transportation. Users were urged to follow OEM-recommended procedures during shipping and handling. Where this has not been done, there has been an above-normal incidence of bearing failures and damage. One owner recommended that all sites own their own container and keep it properly maintained.

The subject of vibration during transportation received some discussion. One user commended that the shock log monitor registered vibration spikes of 18 on the trip back to the plant after an overhaul; GE's recommended limit is 3.5. The depot asked the owner to send the engine back to the shop so it could be checked for bearing damage.

Average vibration from plant to shop was between 7 and 8. No bearing damage was identified. Question: Is the recommended vibration limit too low? An OEM representative responded that high spikes are not of particular concern but continuous high vibration is.

Closed user discussion sessions are particularly valuable. One of the "threads" at the San Diego meeting concerned third-party suppliers, in particular an independent (non-OEM certified) depot. One user offered that the work was comparable to that of the licensed depots and much less expensive.

Another owner, which has more than a dozen LM2500s, said it sent an engine with non-OEM blades to a depot for overhaul and the depot said GE would not allow it to repair those blades—even though the third party is certified to manufacture such parts for military and commercial aircraft. A representative of a cruise line said he sends propulsion engines to any FAA-authorized depot. Yet another owner commented that his company's insurance company accepted third-party parts after a thorough case review; it appreciated the good warranty.

Discussion of exhaust-temperature spreads noted one user's experience with a very high spread that was caused by a "bad" combustor—its shape was not perfectly round. Another owner/operator said they had the same experience at his plant.

A suggested best practice: Conduct water washes through the compressor casing via the borescope plugs rather than by spraying water into the inlet bellmouth. The user suggesting this approach said the engine is cleaner and you use only about half the water and soap.

The experience of field service representatives created a buzz in the room. A steep learning curve was acknowledged. Also, that inexperience may contribute to a stretch-out in outage schedule at no additional out-of-pocket expenditures (fixed-price contract). But revenue opportunities may be lost.

Expected lifetime of lube-oil filters was put at four to five years by a couple of attendees. Hot-section life can vary dramatically from plant to plant. One attendee said his facility was only getting 12,000 hours out of its STIG-equipped unit firing at 1525F; another said his STIG engine was getting 20,000 hours at 1480F. Yet another user pointed out that you can get 25,000 hours out of a hot section if you run at minimum firing temperature and don't start often. Makes sense, but peakers typically are required to start often and run flat out.

The package discussion topics were developed by Chairman Baker, who led the session. He began at the filter house and went through the unit throwing out keywords to remind attendees of something that might be bothering them. Possible discussion topics related to the filter house included the following: prefilters, primary filters, canister filters, instrumentation, chiller coils, inlet heaters, corrosion issues, FOD (foreign object damage) screens, ventilation system issues.

Freeze-up of inlet chiller coils followed a discussion of corrosion prevention in the air inlet house. One user suggested raising water temperature by 10 deg F to prevent icing; another reported adding some ductwork and routing generator discharge air to the inlet house.

Screens at the inlet bellmouth to prevent foreign objects from entering

Repair of HTP blades saves USN big bucks

A recently completed 10-yr study by the US Navy proved what most shore-side owner/operators of LM2500 engines have known all along: The repair and refurbishment of HP turbine (HPT) blades results in overwhelming cost savings/avoidance when compared to installing new production blades during engine shop visits and overhauls.

After testing refurbished HPT blades for a decade, the navy has concluded that the risks associated with this practice are minimal and that the performance of repaired blades is virtually indistinguishable from that for the repaired components. The navy was not able to identify any downside associated with using repaired blades over the 10-yr period. Navy practice had been to replace HPT components each time an engine was removed from a ship for overhaul.

However, the USN will continue monitoring repaired parts in service. Borescope inspections, metallurgical evaluations, and engine failure assessments are required, the service organization believes, to scrutinize the long-term viability of the parts. Plus, more high-time (more than 15,000 hours) operating experience is need to address risk concerns.

According to "Ten years later: A technical and financial review of the USN's HPT blade refurbishment program" (GT2010-22811), co-authored by Robert Neff and Matthew Driscoll of NAVSEA Philadelphia and presented at ASME's Turbo Expo 2010 last June in Glasgow, the navy is going beyond traditional shore-side practice.

The authors suggest that users make efforts to retain all hot-section parts for possible refurbishment any time they are removed from service because of the substantial cost savings. Additionally, they advise that even blades characterized as scrap or considered unrepairable should be retained because repair schemes yet to be developed may make today's scrap tomorrow's assets.

The assistance of General Electric Co's Ben Nagaraj and Chromalloy's Joe Lesch and Wes Mocaby were acknowledged by Neff and Driscoll.

the compressor came under attack. Some users believed that deterioration mechanisms caused liberation of metal fragments from the screens and they damaged airfoils. You hear the same discussion at other user-group meetings.

In fact, some O&M personnel have suggested that the screens be removed altogether. "How many in the room have found debris on the upstream side of the screen?" a gathering of frame users was asked. There was silence. The "no-screen" advocate said, "There you have it."

One person in the LM2500 session said his plant removed the screen from a 1989 engine and replaced it with a rail. The OEM did not approve this because it interrupts compressor air flow.

The package discussion gets granular at times. Belt failures of generator enclosure fans was brought to the floor. Several thoughts were offered, but the one that seemed to make the most sense: Change belts every spring and don't give failures a second thought. Other discussion topics included CO_2 systems and trips caused by false indications, lube-oil flush procedures, package crane maintenance, control systems and the availability of legacy parts, etc.

LM5000 breakout

Session chair and discussion leader for the LM5000 breakout was Chuck Toulou, Ripon Cogeneration LLC, Ripon, Calif; session secretary, Tom Christiansen, senior VP, Strategic Power Systems Inc. The depot presentation was made by ANZ's Chris Martin and MTU Maintenance's Christian Czmok.

It was announced during the general session on Monday morning that GE had contracted with ANZ to provide enhanced customer service for the distribution of LM5000 gas-generator unique replacement parts. Under the agreement, GE will continue to manufacture these parts while the depot will be responsible for handling customer orders, forecasting, warehousing, and product delivery. ANZ has extensive experience serving the LM5000 fleet both as a licensed depot and as a spare-parts provider.

Fleet status at the time of the meeting included 56 operational LM5000s, 12 customer spares, and 12 GE lease engines. Ten LM5000s were listed as inactive and another 10 as retired. One of the depot presenters said, to the best of his knowledge, six engines had been removed from active service between July 2009 and the early part of March 2010—two for LPT stator-case issues, two for HPC vibration, and one each for an LPT rotor issue and AGB issue.

LP compressor rotor (LPCR). One incidence of shaft-rim bolt-hole cracking, originating from a corrosion pit, was identified. Bolt lubricant used during rotor installation might be the underlying cause, but the issue still is under investigation by the OEM.

Seized/locked blades are frequently found in the zero and first stages; cause usually is corrosion deposition in disk slots. The first stage must be removed to make repairs; Stage 0 can be repaired in-situ. Condition can lead to vibration capable of causing CFF cracking. Possible causes of corrosion: ineffective sealing of storage containers, inlet fogging, difficult environment.

Other findings reported by the depots included rear spinner corrosion on mating surfaces and in bolt holes, high rotor run-outs, slightly long blade roots in some instances, and imbalance/vibration attributed to excessive blade gaps (0 to 0.010 in. allowed; up to 20 mils reported). Note that blades with long roots typically are returned to the OEM because there is no authorized repair procedure; however, one user reported


Toulou

using a belt sander to correct blade-root length.

LP compressor stator (LPCS). Lone issue identified was corrosion on vane rails. Apparently it has occurred only on a specific set of units operating in a corrosive environment.

Compressor front frame (CFF). Stationary air/oil seal Teflon damage has been observed in the field and at depots. Depot presenter said there appears to be a delamination issue on the oil seals at bearings 1 and 3, and oil leakage is in evidence when that occurs; Teflon particles have been found in the oil filters. A change in the seal material is expected. Metco 601 is the new material recommended for LM6000s suffering the same type of damage.

HP compressor rotor (HPCR). One incidence of second-stage blade fracture with downstream damage was reported. Root cause is still under investigation.

Cracking of first-stage-disk seal serrations was reported for the first time last year. There were six occurrences, three of which stemmed from cracks that initiated on the seal teeth and propagated. Further investigation identified the issue as a rub against first-stage shrouds. Clearance between rotor and stator has been increased.

HP compressor stator (HPCS). Attendees were reminded that fifth-stage lever arms cannot have a mixture of different part numbers (G05 and G12). Also, G05 is for titanium cases only. Recommendation: Verify that only a single part number is being used; replace lever arms as needed to achieve this goal. Be aware, too, that there are multiple suppliers of lever arms and all arms with the same part numbers may not be exactly alike.

Several bent or broken third-stage lever arms have been reported as well. Collateral damage includes blade liberation and significant compressor damage. Cause often is traced to maintenance activity: For example, a worker steps on lever arms or tools are left between the arms and the casing after maintenance. Best practice: Construct a maintenance bridge to prevent people and tools from damaging the arms.

First-stage shrouds have been found with excessive wear because of contact with the first-stage-disk air-seal serrations. HPC case shrouds can be replaced in the field with a top case. If this is done, consider conducting a fluorescent penetrant inspection of first-stage-disk seal serrations to identify any cracks present.

Finally, excessive wear has been found on the first-stage shroud surface. This results from G01 shrouds not being ground to the proper clearances.

Compressor rear frame (CRF). Mid-flange cracking and wear in the bolt-hole tabs, and bolt-hole elongation, have been observed in many engines. Attendees were referred to SB 197 and SB 203 for suggestions on how to mitigate these issues in the field. Stresses are acceptable after incorporation of bridging brackets (SB 203) and elongation of stiffener-segment bolt holes (SB 197).

The presenter said that discussions between the depots and the OEM have been ongoing relative to the development of a repair procedure to correct bolt-hole elongation without replacing the entire part. An upgrade for the mid flange has been introduced for the LM2500, but the low volume of parts in the LM5000 fleet does not make it a priority item here.

Regarding depot visits, refer to SB 204 for guidance on replacing the mid flange during an overhaul in a manner that minimizes secondary hardware changes. Also, dimensional checks of the CRF were recommended after vendor repairs to be sure the bearing housing is concentric to the frame.

Combustion systems were not included in the prepared presentation, but one user raised concern over combustor swirler wear at 4000 hours. No one else in attendance had experienced this issue. However, such wear has been reported by owner/operators of LM2500 and LM6000 engines.

HP turbine (HPT). Erosion and burning has been observed at the forward and aft inner platforms of first-stage nozzles at the fillet radaii. Degradation may be caused by hard operation, poor fuel quality, steam/water injection, etc. Any one or more of these mechanisms is excerbated by thinning of parent material caused by cleaning processes during previous repairs. Worst case: Damage may extend through to the inner air distribution core when cooling holes become plugged.

Erosion issues were reported for first-stage shrouds. One attendee said shrouds can be replaced in the field but that a significant amount of grinding is required to assure proper fit-up. The OEM and depots recommended against this practice.

HP turbine rotor (HPTR). Cracking of second-stage blades was reported in one engine and required replacement of five airfoils. This engine-specific issue appeared related to previous repair of blade tips. Blade damper cracking also was reported; one depot reported having to replace a complete set of dampers on one engine at 50,000 hours. Recall that this component is similar to a blade spacer and its cracking can be observed on the damper body during inspection.

Turbine mid frame (TMF). Two incidents of oil leakage via the No. 5 bearing housing, and forward stationary air and oil seal, were reported in the last year. Degraded O-ring seals were found on the bearing housings.

Liner clocking was reported at one site. Anti-rotation pins and liner holes/shields were worn through. Root cause: The liner had moved during transportation and handling because support location lugs were incorrectly fitted and the Z ring moved, allowing clocking.

LP turbine stator (LPTS). Two incidents of stator-case cracking were reported in the last year. Recall that two incidents also were reported in 2008 and discussed at the 2009 conference (access www.combinedcyclejournal.com/archives.html, click 3Q/2009, click Western Turbine on cover, scroll to p 53).

One of the cracks found in the year prior to the 2010 meeting propagated almost 360 deg; the second one, about 180 deg. In one incident, the case contacted the rotor, causing blade failure and downstream damage. Cracking can now be addressed via a customized customer repair. This is important because of the shortage of LPT stator cases.

Inner-stage seal wear was discussed briefly. Users were told that no wear is allowed to the 10-14 spool-shaft configuration seals; they must be repaired at exposure. Wear to stator-nozzle inner platforms was found at one site along with associated wear to the rotor-blade angel wings. This site also reported vibration issues believed caused by stator-case *shrinkage,* which is extremely rare.

LP turbine rotor (LPTR). On top of everything else, don't forget to check the pedigree of replacement fasteners. An onsite unit inspection to locate the cause of LPC vibration revealed a missing LPT rotor bolt. The bolt had sheared and self-extracted during operation.

There were no vibration indications at the time of the event, but they appeared during the next start-up. Investigation determined that the bolt failed because of fatigue-related cracks. A detailed rotor exam revealed that 75% of the bolts had manufacturing marks which might be conducive to cracking. One depot checked all of the LPT retainer bolts in its stock and found a surface blemish on about half of them that was related to a manufacturing lot. Those bolts were removed from the warehouse.

O&M tips. (1) Cover oil sumps during maintenance outages and whenever grinding wheels are in use nearby. There have been several reports of bearing damage from debris. An owner/operator commented that there are times when a chip detector alarm is cleared (debris removed) and the unit restarted without consideration for where the contaminants originated. That's not good practice, he said, root cause or the origin of the metal shavings should be identified to determine if there's a larger issue.

(2) Performance improvement usually generates a meaningful change. History repeated itself in San Diego, where discussion focused on the three areas with greatest impact on performance (specific fuel consumption). They are:

- HPT first-stage clearance. A reduction in rotor-to-shroud clearance of 20 mils improves performance by 0.9%;
- CDP aft seal clearance. A reduction of 30 mils improves performance by 0.5%.
- CDP forward seal clearance. A reduction of 20 mils improves performance by 0.5%.

Note that the foregoing data are expected performance improvements for the CF6-50 aero engine (the core of the LM5000) at cruise conditions following a shop overhaul.

(3) Engine handling and transport requirements and recommendations:

- Required: Truck and trailer carrying your engine must be "air-ride" equipped. If it is not, expect the depot to disassemble the engine and inspect all bearings for damage.
- When securing the engine to the truck bed, use the tie-downs provided at the bottom of the transport container. Do not place straps across the top: Shipping containers are not rigid and they can be dented and/or misshapen. Any distortion could compromise container seals and expose the engine to moisture and dirt.
- User recommendations: Always lift the container using the lifting hardware provided. Torque all container bolts at least twice.
- Mention was made of the OEM's new transport system, currently available for the LM2500 and LM6000 only. It does not require an air-ride equipped truck. In brief, the system takes air from the truck and provides an independent cushion for the container and engine.
- When storing an engine, ensure that the environment inside the container is properly maintained to minimize equipment degradation. Place a desiccant in the container—or a small heater—and install a humidity detector that can be read from the outside. Another user suggested a nitrogen blanket. Yet another said to store the container in a building not outside.

  If the engine will sit idle for more than 15 days, depots recommended oil-wetting bearings using Brayco 483 or equivalent. For longer storage periods, oil-wet bearings every 30 days.

OEM presentations. GE's trio of presenters on the LM5000 focused on the OEM's product support

Continues on p 18

Capital Power installs first STIG-equipped LM6000 at

It is oft said that if you're standing still you're falling behind. That's certainly true in the competitive power generation business. Competitors with later-model gas turbines, for example, almost surely can produce more power more efficiently and operate more reliably than you can. And probably ramp faster, too.

Consider GE Energy's LM5000 aeroderivative gas turbine, no longer in production. Wear and tear in demanding industrial service has adversely impacted the reliability of some engines. With the cost of spares increasing and their availability sometimes questionable, at least a few owners are considering upgrades to the LM6000. This is not news; 10 LM5000s have been replaced with LM6000s since the first conversion was completed in December 1999 for Oildale Energy LLC, Bakersfield, Calif, by Energy Services Inc, Farmington, Ct.

But until now, there was not an LM6000 replacement for LM5000 engines equipped with steam injection for power augmentation. Recall that LM5000s were offered both with and without STIG™, the acronym for steam-injected gas turbine. Perhaps half the engines purchased were STIG-equipped. Of the 50+ LM5000s still in service, half have STIG.

GE told the editors about the STIG-equipped LM6000-PC at the Western Turbine Users Inc annual conference last spring and announced that the first unit would be installed at Capital Power Corp's EF Oxnard LLC facility in California. That project started March 1 and was completed in mid May.

The editors waited about six months before calling Capital Power, a major player in the North American independent power business with a diverse portfolio of nearly three dozen generating units totaling more than 3500 MW.

Discussions with Dave Sweigart, GM of Capital Power's California assets (including LM2500, LM6000, and Frame 6 gas turbines) and Susan Richards, senior manager of optimization engineering for US plants were followed up with interviews of engineers at GE and Vogt Power International Inc, Louisville. Vogt upgraded the original heat-recovery steam generator (HRSG) to meet STIG system requirements for the LM6000.

Sweigart first provided background information on the plant. EF Oxnard, he said, produces electric power for Southern California Edison Co (SCE) and supplies steam to an absorption refrigeration system that provides "cool" to thermal host Boskovich Farms Inc, a large producer and packager of produce.

As originally configured, the supplementary-fired triple-pressure HRSG sent all of its HP steam to the LM5000 STIG 120 for power augmentation. IP saturated steam went to the absorption chiller and IP superheated steam to the single-stage LP turbine (for additional power augmentation), which drove the LP compressor. LP steam was used for deaeration.

The plant's purchase power agreement (PPA) influences the gas turbine to cycle daily and operate only during peak hours. Translation: Run 13 (winter) to 15 (summer) hours on weekdays; shut down on weekends. Sweigart said the plant was a high-maintenance facility, difficult to repair, and parts were getting harder to obtain. The company was ready to make a change.

Capital Power had successfully swapped out the LM5000 at its North Island plant for an LM6000-PD with a dry, low-emissions (DLE) combustion system in 2009 and was inclined to do the same at Oxnard. However, North Island, which supplies electricity to San Diego Gas & Electric Co and thermal energy to the US Navy, was not STIG-equipped. Had the company opted for an LM6000-PD at Oxnard, a steam turbine would have been required as well to meet contractual obligations. Note that North Island was GE's first self-perform LM5000 to LM6000 conversion project and Capital Power was satisfied with the job it had done.

Space limitations and other factors militated against installation of an LM6000-powered 1 × 1 combined cycle at Oxnard. When the OEM announced availability of the LM6000-PC with STIG (referred to as the LM6000-PC CDP), Capital Power believed that was the best alternative for the site. But don't get the impression this was an easy project—one simply involving the removal of one engine and its replacement with another. There were many constraints and challenges.

For example, the plant is locked into its PPA until 2020, so there was limited to no opportunity to uprate the facility and sell additional output. Even if that were possible, more capacity couldn't be squeezed from the existing generator. There were budget constraints as well. They dictated that the plant reconfigure the existing HRSG to match the new requirements of the LM6000 rather than replace the 20-yr-old boiler.

GE did not do the Oxnard project turnkey basis. Rather, it provided a change-out kit and engineering support, including a technical advisor (TA). Richards was the project manager for Capital Power, which hired the contractors required for all but the HRSG work.

Sweigart recalled C D Lyon Construction Inc from nearby Ventura as being important to the project's success. "Lyon does work for us all the time," he continued, "and they had a vested interest in the project." Offering his experience to others, Sweigart said it's important for the owner to be proactive to assure jobs like this are completed in a timely manner and within budget. "Hands-on" is engrained in Capital Power's culture, he added.

The proverbial fly in the ointment on the Oxnard conversion was the generator. Sweigart said the LM5000 and LM6000 rotate in opposite directions, making it necessary to change the exciter diode wheel and the three fans on the air-cooled Brush generator. The rotor was pulled and this work was done at the plant.

Ordinarily, one would expect that switching the inlet fan to the outlet and vice versa would be a relatively easy job. Not so at Oxnard. Sweigart said the fans had a significant amount of balance weights and after they were switched and the rotor reinserted in the generator, plant personnel couldn't eliminate the induced imbalance. The rotor had to be removed again and this time sent out for a spin balance. Lesson learned: If you do a similar project, pull the rotor and send it to a competent shop to swap fan locations and spin balance.

The project triggered a New Source Review, requiring environmental impact studies and modeling to prove the more stringent air quality standards would be met with the new engine, addition of CO catalyst, and an upgrade to the SCR. Sweigart said the company was committed to doing the best job it could from an environmental perspective. Maintaining close contact with regulatory authorities was important, he added. The permitting effort for Oxnard took about six months, primarily with the local air quality district.

The new unit is running well. There

EF Oxnard

have been relatively few issues since startup, Sweigart said—including instrumentation. He added that Capital Power is not pushing this machine full throttle as it had the 1990-vintage LM5000. The old engine was 33 MW, augmented to run at 50 MW. The LM6000 is a "low 40s" machine with power augmentation to 50 MW.

Regarding thermal performance, Richards said the heat rate for the LM6000 STIG was predicted to be 2% to 3% better than that for the LM5000. At present, she added, they're getting 2.5%. However, only about a third of the project was justified on heat-rate improvement; remainder of the expected saving was expected to come from eliminating forced outages and their associated loss of revenue and cost of leased engines.

Richards expects the engine will run 25,000 hours before hot-gas-path or other parts require replacement. This unit requires less steam injection than the LM5000, she said, reducing water use by 5 million gal/yr. Annual NO_x emissions are decreased by 9 tons/yr.

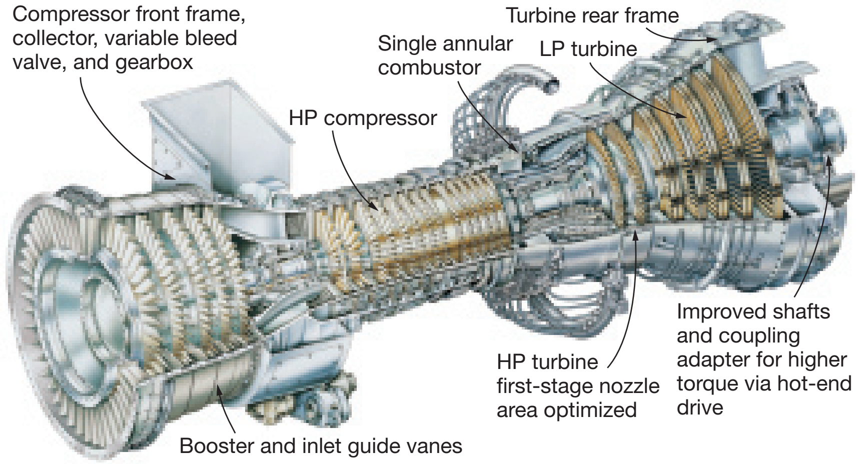
Engine requirements

A conference call with GE engineers dug into the details of the new engine model and the operational flexibility it offers. Participating were Scott Hover, product services program manager for the LM6000; Tayo Montgomery, manager of technical sales support for aero GTs; Mike McCarrick, repowering leader for the Americas; Ted Stokley, customer relationship manager; and Senior Design Engineer Waseem Adhami.

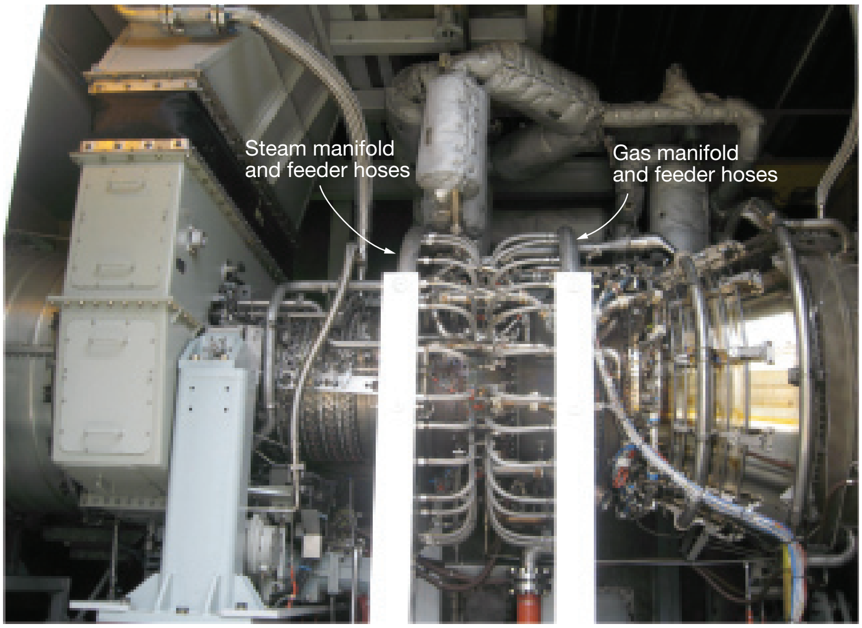
The editors asked Hover to begin with a review of options for maximizing output and/or performance by injecting water and/or steam into the LM6000-PC (Fig 1). Starting from the front of the machine, fine droplets of water can be introduced near the compressor inlet to restore power lost as a result of high ambient temperatures. This evaporative cooling technique is known as Sprint®, a term most LM owner/operators are familiar with.

NO_x emissions are controlled in engines with single annular combustors, like EF Oxnard's, by reducing flame temperature via injection of water or steam into the combustor (Fig 2).

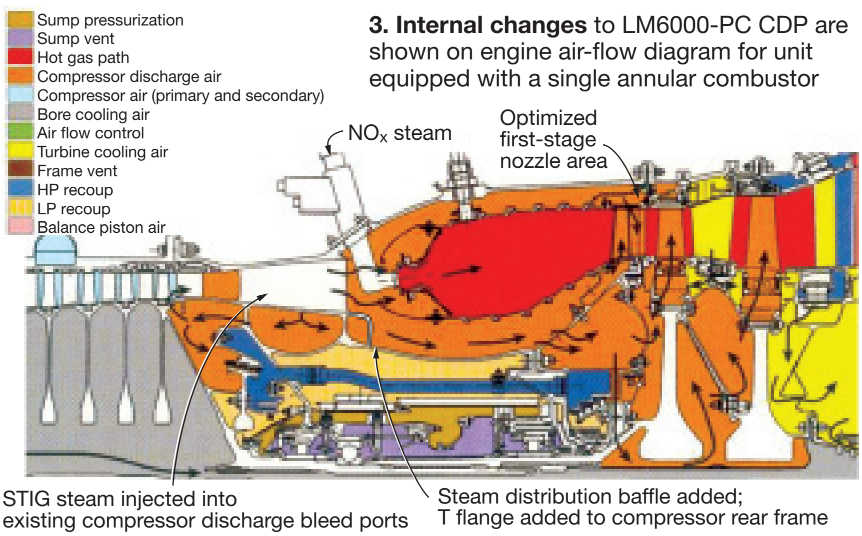
Finally, STIG, which involves introducing HP superheated steam through bleed ports (known as CDP



1. STIG-equipped LM6000-PC, designated the LM6000-PC CDP, shows some minor modifications from the baseline engine. The HPT first-stage nozzle area, shafts, and coupling adapter called out in the diagram have been modified; other parts are standard PC components



2. Combustor arrangement reveals one steam and one gas manifold. Steam here is for NO_x control



3. Internal changes to LM6000-PC CDP are shown on engine air-flow diagram for unit equipped with a single annular combustor

1. Comparing options for the LM6000-PC CDP

Parameter	Base PC	Sprint only	Sprint + STIG	STIG only*
Output, MW	46.1	51.5	55.1	46.9
Efficiency, %	43.1	42.8	45.2	45.5
NO_x steam, 1000 lb/hr	31	31	33	30
Steam for export, 1000 lb/hr	71	81	28	14
STIG steam, 1000 lb/hr	NA	NA	50	50
HRSG total output, 1000 lb/hr	102	112	111	94

*Sprint off

2. How the upgraded HRSG compares to the original

Superheated steam data	Orig HRSG with LM5000	Orig HRSG with LM6000	Upgraded HRSG
HP flow, 1000 lb/hr	71.7	64.5	71.7
HP temp, F	585	597	625
HP press, psia	582	580	650
IP flow, 1000 lb/hr	21.6	19.5	0
IP temp, F	502	494	NA
IP press, psia	200	195	NA
LP/deaerator press, psia	41	32	52

ports) immediately downstream of the compressor, provides owner/operators a marginal increase in output but a substantial boost in efficiency (Fig 3). When Sprint and STIG are used in combination, very significant gains in output and efficiency are possible (Table 1).

Hover said the STIG version of the LM6000-PC was developed for customers (1) upgrading from the LM5000 to LM6000 that had excess steam available or (2) others that had lost their steam hosts and wanted to increase the value of their power-production operations.

It's a niche market: Owner/operators with excess steam are able to sell more electricity at a lower heat rate using only their gas turbine/generators. Investment in a steam turbine is not required. This is why STIG sometimes is referred to as the "poor man's combined cycle." But keep in mind that while capital is conserved, water is not. Revenue from the additional kilowatt-hours sold must offset the expense of water vapor carried out the stack with exhaust gas.

The design challenge was to adapt the LM6000-PC to absorb up to 50,000 lb/hr of 600F steam for power augmentation in addition to the approximately 30,000 lb/hr required to reduce NO_x emissions to 25 ppm at the engine exit. GE engineers had the company's experience with STIG on the LM2500 and LM5000 as a starting point.

Thorough investigations of heat and mass transfer and component life—in particular the lives of HP turbine airfoils—were required. They confirmed that steam was injected at the optimum locations and that the pressures and pressure drops along the gas flow path would assure safe, continuous operation of the engine.

Analyses of other components impacted by the STIG implementation were required as well; in a few instances, design changes were necessary. For example, engineers found that compressor/turbine shafts and the coupling adapter had to be upgraded to accommodate the higher torque associated with the hot-end generator drive.

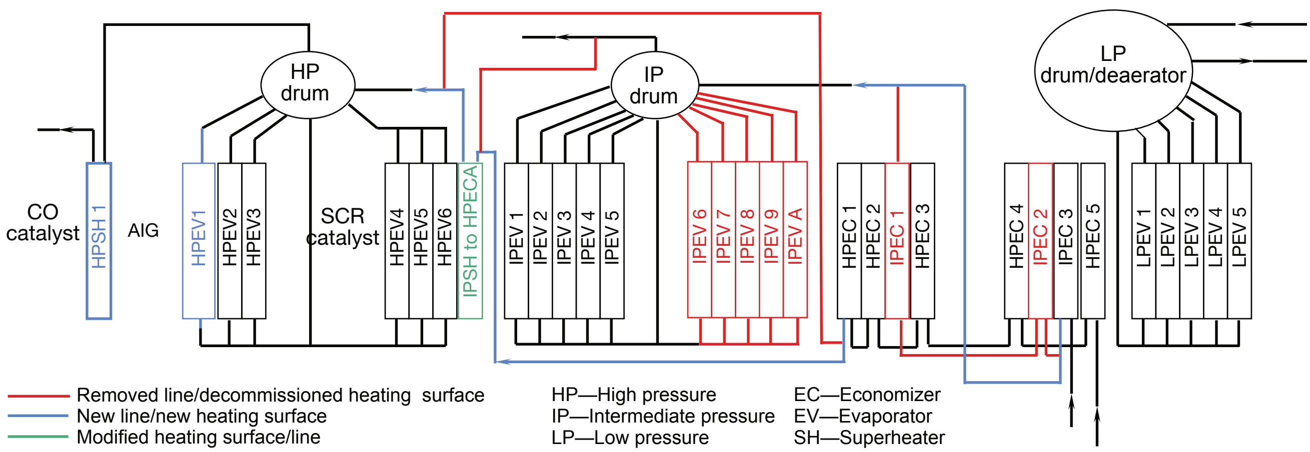
In sum, this was a major design effort which resulted in relatively minor modifications to the base engine required to accommodate STIG. Here's a list of turbine upgrades required:

- Compressor rear frame (CRF) steam-baffle shop mod to ensure even distribution of steam injected into the engine.
- CRF T-flange repair procedure.
- New HP turbine first-stage nozzle segments.
- On-engine steam delivery piping.
- HP turbine nozzle jumper tubes and check valves.

Plus, a new turbine control system was installed.

Package and other onsite work included steam piping and valve mods to route steam from the HRSG to the gas turbine; HRSG work as described in the next section; steam piping and associated purge and drain lines required to deliver steam to the compressor discharge bleed ports.

Wrapping up the discussion, the GE engineers said that conversion from an LM5000 to STIG-equipped LM6000 improves power output and efficiency and increases reliability and availability with virtually no impact on start times. They suggested that conversion decisions be made only after conducting studies to evaluate generator and transformer capacity, exam-



4. Heat-recovery steam generator, which supplies STIG and NO_x steam to the gas turbine required a redesign effort, some new components, and modification of others to accommodate the change in engines from LM5000 STIG 120 to LM6000-PC CDP

5. New HP evaporator module, located immediately downstream of the ammonia injection grid (refer to Fig 4), is lowered into place. The single HP superheater module also was replaced (left)

6. Fresh charge of SCR catalyst offered improved NO_x destruction efficiency and lower pressure drop (right)

3. Impact of installing CO catalyst*

Pressure drop, in. H_2O	1.8
CO at turbine exit, ppmvd at 15% O_2	75
CO at stack exit, ppmvd at 15% O_2	46.3
VOC at turbine exit, ppmvd at 15% O_2	4.7
VOC at stack exit, ppmvd at 15% O_2	2

*CO catalyst was added as part of the LM6000 upgrade

4. NO_x emissions halved with new SCR

Parameter	Original	After upgrade
Pressure drop, in. H_2O	2.2	1.4
NO_x at turbine exit, ppmvd at 15% O_2	25	25
NO_x at stack exit, ppmvd at 15% O_2	4.1	2
Ammonia slip, ppmvd at 15% O_2	10	5

ining HRSG capability, and reviewing existing air permits and PPAs.

HRSG modifications

Perhaps the most challenging part of converting EF Oxnard to the STIG-equipped LM6000-PC was the design and field work required to upgrade the HRSG for the new service. As a result of the New Source Review, CO catalyst was added to the boiler and the SCR upgraded to limit NO_x emissions to 2 ppm—down from 4.1 ppm.

The engineering study phase of the HRSG project began by modeling the boiler in its current condition using using Vogt's proprietary design software. This effort explored three levels of performance with varying LP and deaerator pressures, the corresponding IP and HP economizer inlet water temperatures, and different targets for HP and IP superheated steam. Options were presented for modifying the existing unit to meet each of the three design points.

Table 2 shows the data compiled during the modeling study. The first column is self explanatory; information presented is for the original HRSG/LM5000 configuration. It agreed with actual plant data, validating the model's accuracy.

The second column presents what could be expected by using the original HRSG with the LM6000. This information revealed both *ASME Boiler and Pressure Vessel Code* violations and unacceptable performance data. For example, superheated IP steam used as a power boost for the LM5000's LP turbine has no purpose in the reconfigured plant.

However, the 36,000 lb/hr of IP saturated steam for the absorption refrigeration unit had to be maintained as part of the retrofit. Modeling made it clear that new tube bundles (harps) would be required for the superheater section and the first HP evaporator section (Fig 4).

The third column shows performance predicted with the new harps and other necessary modifications (Fig 5). HP steam flow, temperature, and pressure met the LM6000-PC CDP requirements and the saturated IP steam flow the absorption reefer's needs.

Peter Allison, a member of Vogt's aftermarket business development team with experience in thermal modeling, said that the decommissioned lines and heat-transfer surfaces shown in red in Fig 4 were disconnected and isolated with appropriate pipe caps and drains in case the plant's steam requirements change in the future. The pressure-drop penalty for leaving the superfluous heat-transfer surface in place is about 1.5 in. H_2O.

Vogt provided Capital Power with two different formulations of SCR catalyst, each with two options for varying gas-side pressure drop and guaranteed life, and one formulation of CO catalyst with options for varying pressure drop and life. Performance of the catalyst formulations selected is detailed in Tables 3 and 4.

Vogt's scope of work included the following:

- Turnkey construction—including demolition and installation, construction management, onsite TA services, and commissioning of the upgraded HRSG and related auxiliaries.
- SCR catalyst replacement and new CO catalyst—including design, structural modification and reinforcement, removal/installation, access doors, casing mods, instrumentation ports, etc.
- Replacement of the HP superheater and first HP evaporator harps fabricated by Chanute Manufacturing, Tulsa.
- Conversion of the original IP superheater into an additional HP economizer harp, including testing.
- Decommissioning of half the IP economizer surface and two of the three IP economizer harps.
- Piping modifications.
- Boiler cleaning and hydro. Allison stressed that cleanliness was important on both on the water and gas sides of the HRSG. Ductwork and external tube surfaces were thoroughly cleaned before startup with catalyst in place because schedule constraints did not allow for first fire without catalyst installed to burn off oil and other foreign substances from the gas side.

Continued from p 13
capabilities (personnel and service centers) and its technical and safety programs for the engine—including work being done to mitigate cracking of seals, blades, disks, disk spacer arms, etc.

First part of the GE session concerned LM5000 to LM6000 upgrades. The OEM acknowledged that it typically worked with Energy Services Inc (most often referred to as ESI), Farmington, Ct, on repowering projects of this type. However, it recently completed two projects in-house, both of those for Capital Power Corp.

Most significant was the replacement of an LM5000 STIG 120 with the first LM6000 STIG engine at EF Oxnard LLC, Oxnard, Calif. This project is detailed in the accompanying sidebar (previous four pages).

LM6000


Atkisson

Session chair and discussion leader for the LM6000 sessions was Bryan Atkisson of Riverside (Calif) Utilities; session secretaries, Steven Giaquinto and Cindy Alicea of SPS. Depot presentations were made by TCT's Dale Goehring and Steve Willard, MTU Maintenance's Ralph Reichert, and IHI Corp's Kenichrio Udea.

Nearly 140 users attended the open sessions conducted by the depots. The format for the LM6000 breakout was similar to the lineups for the LM2500 and LM5000 sessions. But with more material to cover, time constraints dictated that the LM6000 speakers summarize subject matter and refer attendees to details in the reference material provided by the depots to all owner/operators.

Those findings not addressed from the podium typically required no explanation and would have been of little interest to the majority of attendees. A positive result of not including "everything" in the live program was that the speakers were able to hold the attention of participants and keep the discussion upbeat.

The LM6000 continues to be the "aero of choice" in the electric power generation sector, but the competition is not going away. In 2009, according to Mark Axford of Houston-based Axford Consulting LP, global purchases of aero GTs for power generation totaled 5838 MW, off 34% from the previous year because of the economic slowdown.

Market stats. Interestingly, GE captured 72% of aero orders outside the US, but achieved only 38% market share at home. Rolls-Royce, which hardly has made a dent in the US generation market over the last several years, captured a whopping 52% of the 1594 MW sold here with orders for 13 Trent 60s. Pratt & Whitney, which now has a fleet of about 200 FT8s in service, slipped to third place with a 10% share, according to Axford's numbers.

Regarding the LM6000, nearly 1000 engines have been sold worldwide to date. As of Feb 15, 2010, the fleet totaled nearly 20-million operating hours and the high-time engine was at 113,725 hours. More than half of the engines in operation are PC models.

Slightly more than three-quarters of the engines sold are equipped with single annular combustors (SAC), the remainder with dry, low emissions (DLE) combustion systems. Thus, it was no surprise that Goehring's informal audience survey revealed that the majority in attendance used water injection for NO_x control.

Half the owner/operators enhance engine performance using Sprint™. Critical-parts life tracking continues to gain momentum, with 46% of the San Diego attendees subscribing to its benefits. The majority of attendees have simple-cycle engines, which was expected. Almost half of the users were attending a WTUI meeting for the first time.

The importance of Service Bulletins (SBs) and Service Letters (SLs) was stressed by Goehring. A list of those documents issued or revised in 2009 were published in the depots' reference material. If you don't have a copy you can get this information at www.wtui.com, but you must be a registered user to access it. Join WTUI today!

IHI's Udea stepped to the podium and began his presentation with a review of failures associated with staging valves for DLE combustors on PB and PD engines. Failures were traced to damaged transient voltage suppressors (TVS).

Investigators found the staging valves were subject to high temperatures when the engines were on standby because the solenoid coils remained energized when the valves were closed. Recommended action to prevent failures in the future: (1) Relocate the TVS away from the valve and in a junction box for ease of replacement. (2) Change control logic so the solenoid is not energized when the valve is closed. Consult the LM6000 notes prepared by the depots for details, including wiring diagrams.

An igniter issue was the next item on Udea's list. Several engines experienced "fail to light off." Field investigations revealed that the igniters were not functioning. Two reasons were identified among the affected engines: (1) Igniter tip missing. (2) Excessive clearance between the electrode tip and igniter case. Cause has

not yet been determined, but corrosion is suspected.

Semi-annual inspection was recommended for verifying the clearance between the electrode tip and igniter case within the OEM's specified limit of 8 mils. One user in the group recommended more-frequent inspections. He spoke of an igniter liberation on one of his units that caused $1 million in damage to the first and second turbine stages. Incorrect assembly of the ignition system was believed to have been the cause.

VBV inoperability was the final topic assigned to Udea. The clues: Engine not producing rated power; online monitor revealed degradation in compressor efficiency. Investigators found that a variable bleed valve could not be closed completely because four sleeves at the VBV hinges were missing and they caused clevis damage.

Root cause was thought to be a bolt failure from high vibration during engine low-load operation. Daily-start combined cycle required the GT to hold at 5 MW while the steam turbine warmed up. What to do: Inspect sleeves semi-annually; replace damaged sleeves.

Compressor front frame (CFF) hardware problems were covered by MTU's Reichert. Reports from shop and field engineers revealed wear on VBV lip seals, wearing and bending on the rod-end bearings and their linkages, loss of nuts and bolts on the VBV bell-crank clevis, and incorrect operation of VBV doors.

Cycling and/or partial-load operation is one cause of wear and tear. Attendees were reminded that failure of VBV linkage bolts can cause partial loss of control over VBV doors, which are the last line of defense against foreign material—such as nuts, bolts, etc—in the air collector from entering the air stream. Also, that the effectiveness of the lip seal is important to overall engine performance. Recommended reading: SBs 209, 237, and 250, and SL6000-06-05R1.

Compressor rear frame (CRF). Oil leaks in the CRF can cause engine smoking and frame coking, as well as the loss of oil. One cause identified was elongation of loop clamps (thermal growth) and sump-area stresses that contribute to clamp distortion. Investigators found that clamps would slide off the oil-tube wear sleeves and wear through the tubes. Users were referred to SBs 233 and 236 and told that if the recommended work was done during the next depot visit the leakage incidents would cease.

High-pressure turbine (HPT). Second-stage nozzles with PN L43529G05/G06 suffered excessive oxidation before end of expected life. G11/12 replacement was an interim fix that allowed the part to achieve expected life.

It was superseded by G09/G10 (refer to SB 124) featuring an extension of the TBC over the leading edge. Users were advised not to intermix G09/G10 with G05/G06 because of the possibility of overheating the leading edges of G05/G06 nozzles.

SB 238 introduced the 2080M12G07/G08 nozzle. It has improved cooling to deliver more air to heat-affected zones and maintain temperatures below the oxidation threshold. Attendees also were told that 2080M12 segments couldn't be mixed with the L43529 segments because of the different curvatures of their respective leading edges and other design differences. If you lose only one segment you still have to replace the row unless a replacement L43529 segment can be obtained (these nozzles are no longer in production). The 2080M12G promises longer life than its predecessors.

LPC blade and case erosion on PA and PC engines. Leading-edge erosion of Stage 0 rotating blades, attributed to Sprint, created rough surfaces on these airfoils. Recommended action: Monitor blade condition with regular inspections, blend repair in accordance with OEM specifications.

Erosion groove in the LPC case on drip-down edge of first-stage blades was attributed to Sprint. Check crack depth during borescope inspection and repair according to recommendations in the IRM.

Bearing failure. Take alarms seriously was the clear message here. Failure to verify and/or validate alarms—chip detectors, sump temperatures, vibration, etc—and to identify reasons for shutdowns before restarting is conducive to major damage, as described by the MTU speaker. It's important that operators are well trained and understand potential damage scenarios.

The case study presented involved the complete destruction of the No. 4B bearing (an empty race was in evidence), which caused axial shifting of the HP section and considerable damage to rotor and stator components. The root cause had not been determined prior to the presentation.

TCT's Steve Willard replaced Reichert at the front of the room and began by discussing revised thinking on LPT first-stage shroud gaps. Visual gaps between blade shroud interlocks were a "no-no" two years ago, the condition treated as "unserviceable."

Customer-driven concerns initiated a review of the condition and as of June 2009, shroud gaps are allowed on first-stage LPT blades *only*. In the OEM's words: "Interlock clearance/looseness due to loss of airfoil pretwist is permitted with no rough/uneven interlock wear."

Next subject: Two unscheduled engine removals caused by shank separation on fifth-stage LPT blades in PC and PD machines. Misalignment and airfoil twist were observed and associated with abnormal wear in tip shrouds which resulted in HCF in the shank.

The combustion system was next and a review of component history (G32/G35 and G39/G41) was the first agenda item. You can come up to speed by reviewing material published in last year's report (access at www.combinedcyclejournal.com/archives.html, click 3Q/2009, click Western Turbine on cover, scroll to p 57). Willard then breezed through key combustor issues, including disengagement of primary swirlers, cracking of primarily swirlers, and anti-rotation tab wear.

HPT first-stage disk. The disk liberation incident that occurred during testing of an on-wing CF6-80A engine several years ago (you probably remember the pictures which made their way around the Internet), was reviewed once again.

Users were referred to SL LM6000-IND-06-03 (issued June 2006) and SBs 177, 210, and 231. SB 177 detailed the NDT inspection required to identify the type of separation in the dovetail slot that caused the incident cited, SB 210 the rework necessary to mitigate the issue. Recently, SB 177 and 231 were canceled and replaced by SB 241 (April 2009), which introduces inspection requirements and mandatory timing.

Diameter W or "arm pit" wear erosion was Willard's next topic. Several first-stage disks have been removed from service in the last few years because of erosion in the Diameter W area caused by ingested dirt that gets trapped in that cavity. Speaker stressed that there was no "wiggle room" on serviceable limits because of the critical nature of the area; once erosion is beyond the maximum repair limit, the disk is considered unserviceable.

SB 246 (October 2009) introduced two methods for preventing erosion:

New engine update: LM6000, LMS100

Enhancements of successful aero engines are a focus of GE Energy, a strategy that's in lock-step with the need to build more flexibility into gas-turbine assets to support the integration of renewable resources into the generation mix (see special report, "Integrating Renewables. . ." elsewhere in this issue).

Darryl Wilson, VP of aeroderivative GTs for GE Water & Power, one of the three business units that comprise GE Energy, said in early October, "Around the world, our customers are telling us it's no longer enough to provide equipment with . . . high levels of power output, economy, reliability, and availability. Today's and tomorrow's customers want those capabilities plus low emissions and fuel flexibility." New GE engines are capable of burning ethanol and other biofuels in addition to conventional fuels.

Wilson reported that the latest enhancements to the LM6000 product line—the PG and PH engines—hit critical validation testing milestones in the early fall. The PG, equipped with a single annular combustor, was released for package testing at GE's manufacturing facility in Houston. The PH, the dry low-emissions equivalent of the PG, is equipped with the company's DLE 2.0 combustion system.

GE reported that the new LM6000 aeros offer significant increases in simple-cycle power and in exhaust energy for cogeneration applications. The higher output is achieved within the same package footprint as existing 50-Hz engines, which translates to a substantial boost in power density.

Key to the improvements are materials and technology upgrades previously demonstrated on the CF6-80E aircraft fleet, which has about 450 engines in operation and an experience base of well over 8-million flight hours.

In a 2 × 1 combined-cycle arrangement, the PG and PH are designed to produce up to 150 MW at 53% efficiency, depending on the configuration selected.

Both the PG and PH can be incorporated into packages for 50- or 60-Hz service. Former will be assembled at a GE facility in Hungary, latter in Houston.

LMS100. The latest news on the LMS100 is that GE is now offering the engine with a DLE 2.0 combustion system, which is capable of sub 25-ppm NO_x emissions without water injection. Rated output of the new package is 101 MW in a simple-cycle configuration at 44% efficiency.

When the LMS100 was introduced in 2003, the focus was simple-cycle operation. Now the OEM is touting its value in CHP (combined heat and power), combined-cycle, and mechanical-drive applications as well.

(1) An air baffle insert for "older" HPT disks and (2) a redesigned HPT disk. Note that the baffle reduces impact energy and creates a barrier to minimize the amount of dirt in the cavity.

Oil seal Teflon delamination. High oil consumption associated with Teflon delamination on No. 1 and/or No. 3 oil seals has forced the removal of several engines. The issue surfaced after seals had been removed and replaced and passed inspection. No reason was given. SB 254 and 256 suggest replacing the Teflon seals with a metal-sprayed material. Expected availability of new parts was fall 2010.

Abnormal HPC events. Several HPC failure events have been attributed to off-schedule operation as a result of damaged or worn VSV hardware—including bent lever arms, severely worn bushings, and loose fasteners. Such anomalies disturb air flow and cause damaging "pulses" that rotating components are forced to pass through. Proper inspection and maintenance are critical to avoiding such situations.

Other abnormal HPC events include foreign or domestic object damage and damage caused by unapproved repairs—incorrect blending, in particular.

Performance loss and restoration. Discussion paralleled that in the other LM sessions, discussing losses that can be recovered without repairs through compressor washing and instrumentation calibration, and those that require hardware changes. The latter category includes losses from flow-path erosion and increased clearances between rotating and stationary parts.

Critical-parts life management of industrial engines is motivated by the ever-more demanding nature of electric power generation. The operating regimen of engines for generation is inching closer to those in aero and marine service—where lifetime tracking of parts is standard practice. And the more renewables added to the generation mix, the more starts and fast ramps these engines will experience (see special report on integrating renewables elsewhere in this issue).

If your plant is not currently tracking the lifetime operating histories of critical parts, it's time to get involved. The cyclic life limits of PC and PD parts are published in GEK105059 Ch 13; PA and PB parts in GEK 98493 Ch 13. If plant staff is unable to design, implement, and fulfill a rigorous tracking program, keep in mind that Strategic Power Systems Inc, Charlotte, provides such expert service (contact Lynne Bellizzi at bellizzi@spsinc.com).

LMS100

Session chair and discussion for the LMS100 sessions was Don Haines, plant manager, Panoche Energy Center, Firebaugh, Calif; session secretary, Cindy Alicea of SPS. The big difference between the LMS100 sessions and those for the other GE aeros was that there was no depot involvement.


Haines

Participation was by owner/operators and the OEM.

The opening message was that the LMS 100 commercial fleet had grown considerably in the last year. At the time of the 2009 meeting, only five units were in commercial service—four in the US and one in Argentina. By the 2010 conference, 17 LMS100s were producing power at 10 plants in five countries. Thirteen of those units at six plants in three countries were represented in San Diego. Another LMS100 was in commissioning when Haines called his session to order and five more units were under construction.

The first presentation after Haines' opening remarks was by Ryan Wanner of Wood Group Power Operations, who explained how the Panoche Energy Center used its PI system to automate reporting. In these days of ever-shrinking plant staffs, automated record-keeping certainly has quantifiable benefits.

Wanner explained the process used by the Wood Group operations team and took attendees through the various screens with real-time data. He said the data collected also were used to update the SPS ORAP® system monthly.

The extensive GE presentation focused on a review of field events, fleet issues, and suggested improvements. Many of the issues and punch-list items have been/will be resolved quickly and there would be little value in mentioning them here. LMS100 owner/operators who do not already have access to this information can get it at www.wtui.com by registering with the user group.

To illustrate the depth and value of the presentation regarding suggested improvements, consider the following thread regarding hydraulic accumulators:

- Background. IGV and VSV accumulator O-ring leaks occurred at one site; oil was contained within the package.
- Investigation. Leaks were attributed to use of under-rated O-rings (vendor quality issue). Rings installed were good for 2900 psig service, but the required rating was 3600 psig.
- Field action/improvement plan. (1) Implemented a process to assure that hydraulic O-rings from this supplier would be inspected and their ratings verified prior to use. (2) Developed instructions that enables users to properly inspect hydraulic-accumulator O-rings and to replace them as required. CCJ

Cogen plant reduces energy cost, emissions while improving service reliability

Timely permitting, financing, and construction of public-works projects generally are difficult goals to achieve in the nation's most populous state. Competing interests, public skepticism, lack of money, and plain old politics militate against building just about anything in California. Even projects that make good sense, like cogeneration plants, can drag on for years.

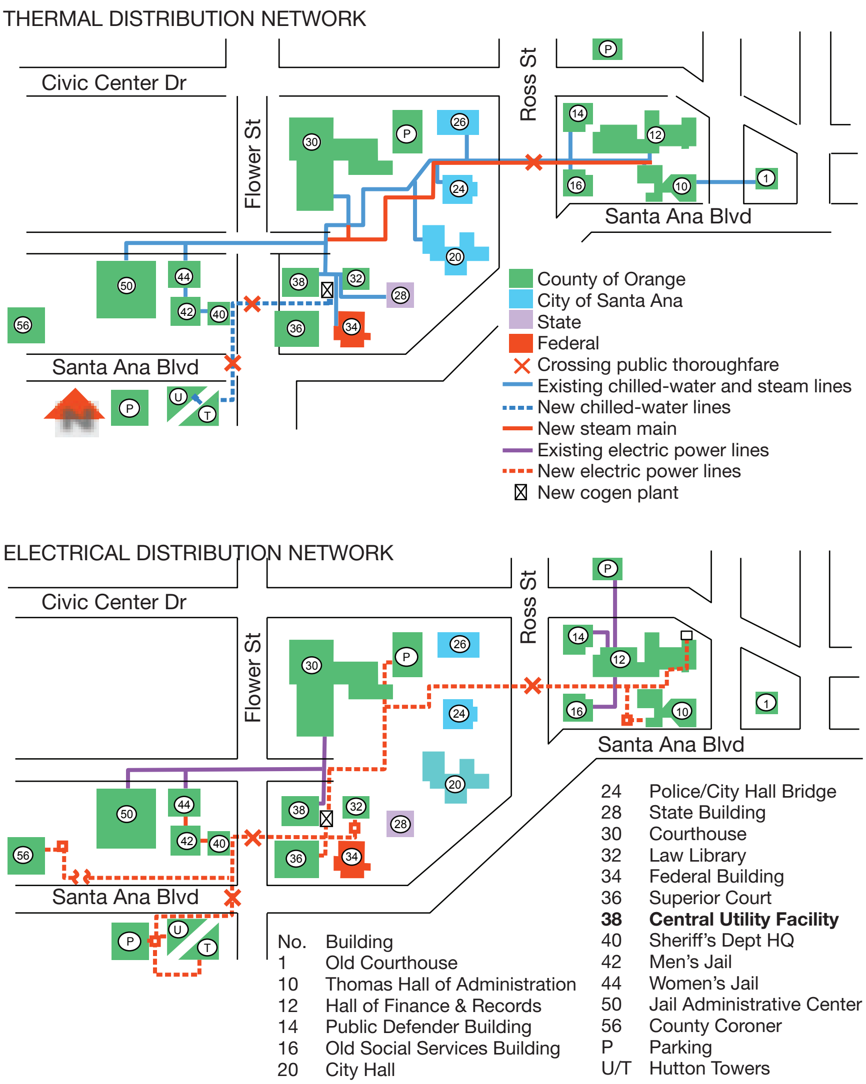
The Orange County Cogeneration Plant is a case in point. Gus Fischer, today manager of facilities operations for the county, was a young engineer in the mid 1980s when he and colleagues at the Central Utility Facility (CUF) in Santa Ana proposed building a cogeneration plant to serve the surrounding Civic Center Campus.

By way of background, the CUF was built in 1968 to provide steam and chilled water to the many city, county, state, and federal buildings on the sprawling campus. Electricity was supplied by Southern California Edison Co (SCE).

Fischer and his co-workers never gave up on the idea and their perseverance paid off—albeit a quarter of a century later—when the cogen plant began operating in November 2009, powered by two 5.2-MW Taurus 60 gas turbines from Solar Turbines Inc, San Diego. Steam is produced by supplementary-fired heat-recovery steam generators (HRSGs), supplied by Rentech Boiler Systems Inc, Abilene. The boilers are each rated 28,000 lb/hr at 265 psig with the turbines at maximum output and duct burners off.

In the end, the "makes good economic sense" argument for building the plant in the mid 1980s was not what moved the project forward, Barbara Tidball, senior project manager for Orange County Public Works, told the editors. Although economics was important, she said, the key drivers were reliability and "green" initiatives. Californians hadn't forgotten the state's electricity crisis at the beginning of the millennium and grid independence was high on the agendas of project supporters.

The cogen plant also was viewed as



1. Distribution systems for both thermal (top) and electrical (bottom) energy at Santa Ana's Civic Center Campus serve city, county, state, and federal buildings the cornerstone of the county's efforts to reduce its carbon footprint. Emissions from the facility's gas turbines would be only a fraction of those from the CUF's steam boilers. Plus, the initiative provided the opportunity to modernize campus-wide energy distribution systems and upgrade office buildings to green standards.

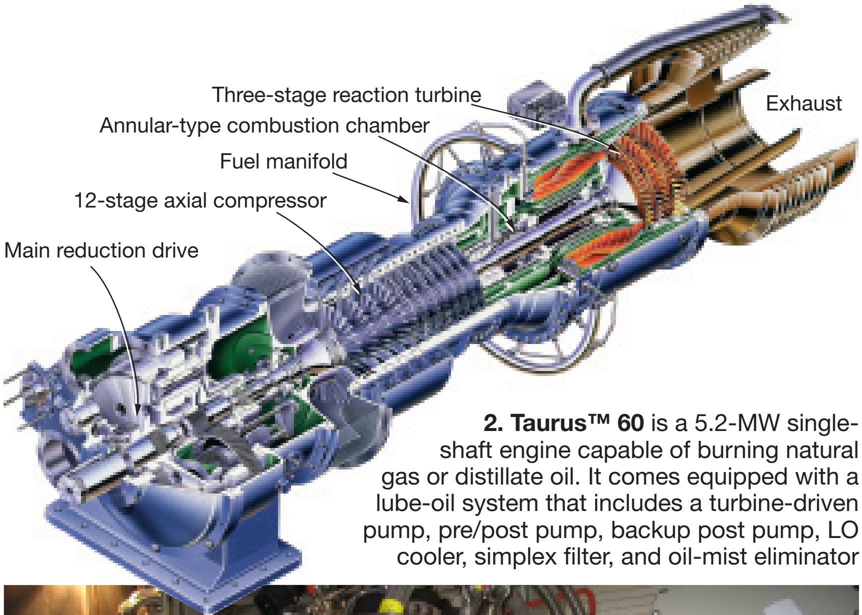
Energy distribution. The underground thermal and electrical distribution networks for the Civic Center Campus are described in Fig 1. San Diego-based Rick Lyons, PE, VP of Syska Hennessy Group Inc's Energy Services organization, the engineer/project manager for the infrastructure upgrade and cogen project, and colleague Al Ribaudo, director of energy services, told the editors that installation of piping and electrical cable had its challenges.

For example, Syska had to jack and bore across several four-lane roads while adhering to very strict requirements on street interruption. Also, the new distribution cable and steam piping had to be installed without disturbing water and sewer lines and other underground infrastructure.

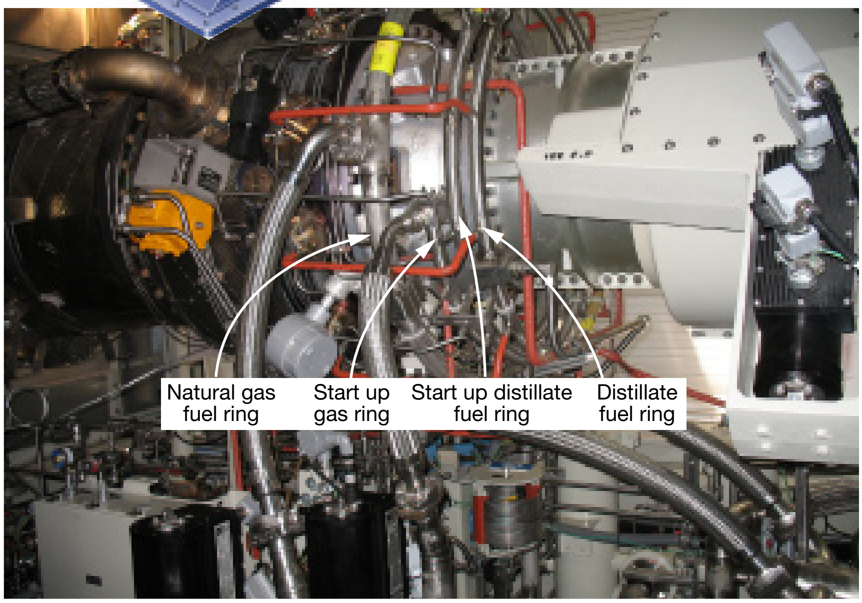
Most of the campus buildings were built between the mid 1950s and the early 1970s, and some steam mains did not pass infrastructure evaluations for continued use long-term. By contrast, the chilled-water piping was in good condition and retained. The original steam lines were abandoned in place and a new Perma-Pipe grid was installed throughout the campus. Pipe rests on a bed of sand within a trench which also accommodates the electric distribution cable. Steam sendout is at 85 psig; pressure is reduced to 20 psig at the campus buildings using pressure reducing valves.

Perma-Pipe Inc, Niles, Ill, manufactured the pre-insulated pipe, which is protected by an outer steel jacket of 22-gauge thickness. Both steam send-out and condensate return piping share the insulated space within the jacket. Diameter of the steam piping is 6, 8, or 12 in., depending on its location on the grid.

The original electric distribution system delivered 12-kV power supplied by SCE to all buildings. Utility transformers at each location dropped the 12 kV to 4.16 kV and power delivery was metered. Those transformers were removed at county buildings and replaced by 4160 to 480 V transformers supplied by Eaton Corp. The high-side voltage on the Eaton transformers is the same as that at the generator terminals. Note in Fig 1 that the cogen plant

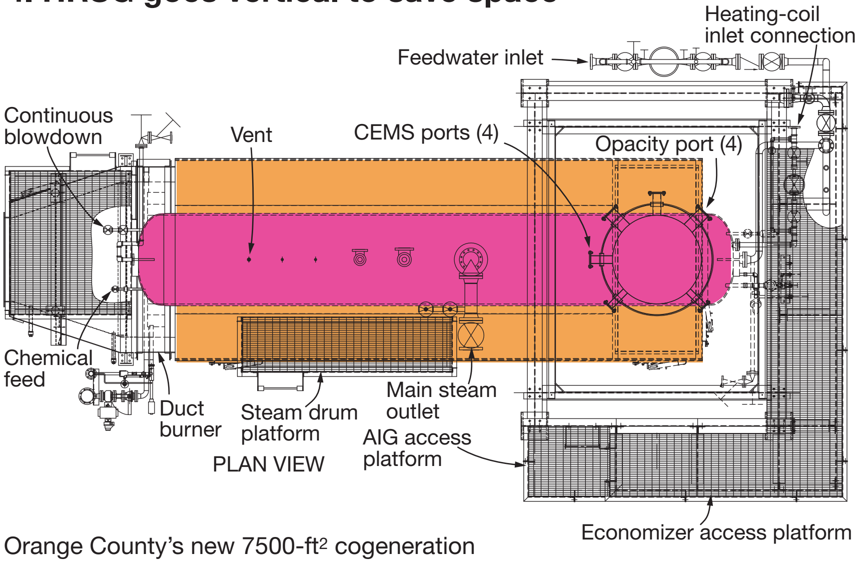


2. Taurus™ 60 is a 5.2-MW single-shaft engine capable of burning natural gas or distillate oil. It comes equipped with a lube-oil system that includes a turbine-driven pump, pre/post pump, backup post pump, LO cooler, simplex filter, and oil-mist eliminator

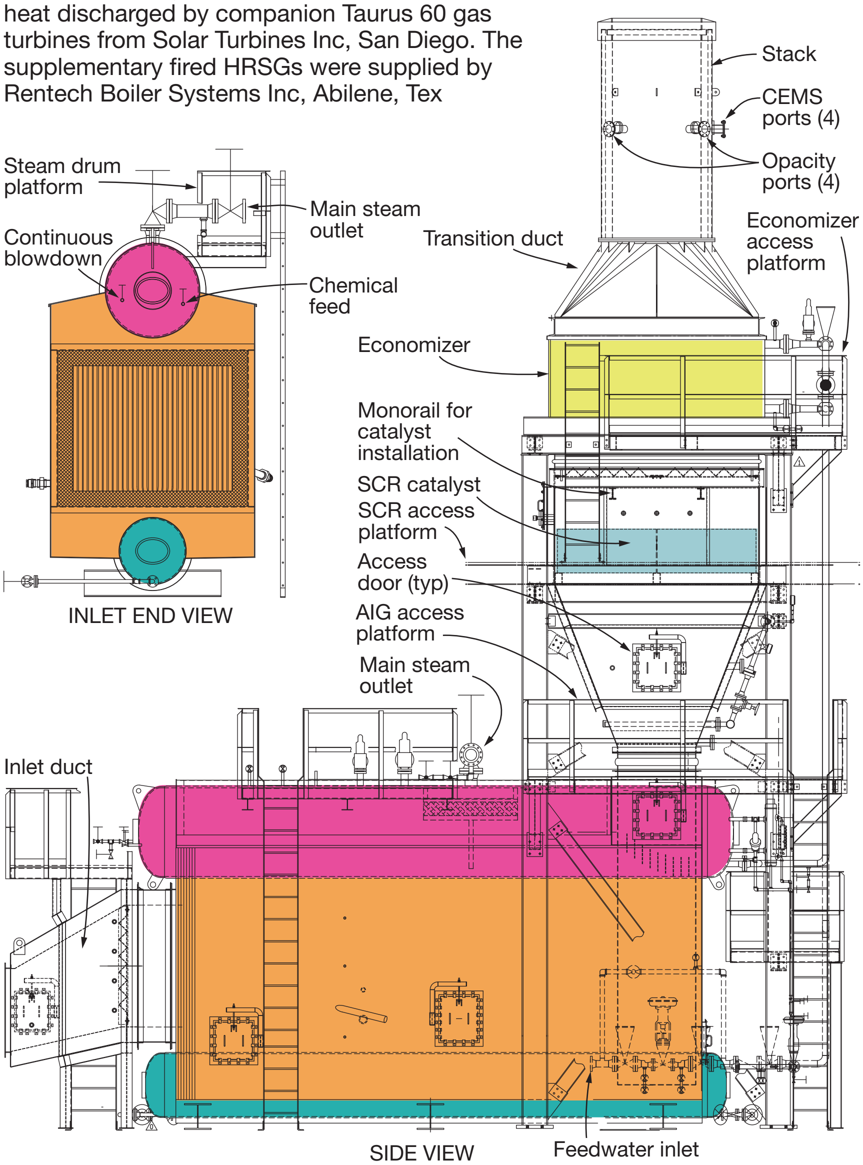


3. Compression skid boosts gas pressure from 40 psig as received to the 265 psig required by the Taurus™ 60's combustion system. Three skids are installed (one a spare) to remove liquids, particulate

4. HRSG goes vertical to save space



Orange County's new 7500-ft² cogeneration plant is integrated with the existing 18,100-ft² Central Utility Facility serving the Civic Center Campus in Santa Ana, Calif. Its two heat-recovery steam generators together produce about 56,000 lb/hr of 265-psig saturated steam from the exhaust heat discharged by companion Taurus 60 gas turbines from Solar Turbines Inc, San Diego. The supplementary fired HRSGs were supplied by Rentech Boiler Systems Inc, Abilene, Tex



supplies electricity only to county buildings but provides thermal energy to all buildings.

The gas turbines are sized to handle the county's peak campus load, based on records provided by SCE. A 10-MW 12 to 4.16 kV transformer was purchased by the county to fully back up the gas turbine/generators in the event of an outage. Reliable utility services are necessary 24/7 because of the two prisons located on campus.

Peak electric demand currently is 8.1 MW and the peak steam requirement 65,000 lb/hr—numbers unlikely to increase anytime soon because of the economic turndown. The current interconnection agreement requires the county to import a minimum amount of electricity to prevent islanding. The next agreement will permit export.

The dual-fuel Taurus 60s feature a 12-stage axial compressor with a 12.2:1 pressure ratio; the reaction-type turbine has three stages (Fig 2). Generator is a wye-connected synchronous machine with a brushless exciter. Chiller coils in the air inlet houses allow the gas turbines to maintain rated output year-round; water for the coils comes from the campus chilled water system. The CUF is home to three steam-turbine-driven centrifugal chillers (900, 1300, and 2000 tons) and two absorption units rated 1200 tons each.

Primary fuel is natural gas, which is supplied at about 40 psig and boosted to the GT requirement of 265 psig with a prepackaged onsite compression system equipped to remove both entrained liquids and particulates (Fig 3). Three gas pretreatment skids are installed—one per engine and a spare. A supplementary gas line has to be installed at the plant to accommodate the gas turbines.

A special permit was granted to burn distillate to mitigate reliability issues. The turbines can reach rated output on Amber 363, an ultra-low-sulfur oil (less than 1 ppm) which was developed as a standby fuel with the emissions requirements of California's South Coast Air Quality Management District Regulation 1146 in mind. HRSG duct burners are capable of firing only natural gas.

The Rentech HRSGs are equipped with CO catalyst beds and SCRs to restrict NO_x emissions to 2 ppm. Physical constraints on boiler length forced engineers to rely on vertical-flow SCRs and economizers (Figs 4-6). The CO catalyst is in the evaporator section and not shown on any of the drawings.

Operational flexibility is pro-

5, 6. Waterwall surface for HRSG is in the foreground of photo at left looking down at the Taurus 60 package. At right, duct burner and fuel skid are visible looking toward the rear of the waterwall section. Such tight spacing required locating catalyst beds and economizer in the vertical section shown clearly in Fig 4 but not here

7. Each of the rooftop dump condensers, needed during process upsets, is capable of condensing all of the steam its dedicated HRSG can produce with duct burners off

8. Architectural curtains obscure from view all rooftop equipment—including gas-turbine air inlets and dump condensers

vided by a sophisticated control system that enables the gas turbines to closely follow load, and by two dump condensers (one per GT/HRSG train) located on the plant roof, each capable of condensing the unfired steam output of a boiler (Fig 7).

The cooling towers that support the chillers also are the source of cooling water for the dump condensers. Fine-tuning of plant operations was the primary goal of Tim Corbett, plant manager, for 2010.

End notes: environmental. In addition to reducing CO and NO_x emissions to state-of-the-art levels, the plant's noise profile did not increase with the addition of the gas turbines, HRSGs, and system auxiliaries. Scenic vistas were maintained by use of appropriate architectural curtains to block from view rooftop equipment (Fig 8).

9. Skylights minimize electrical load for lighting during the day

Energy conservation. Lighting load in the cogen plant was minimized by use of skylights (Fig 9). Conservation efforts in campus buildings have had a significant positive impact. Energy management systems have been upgraded to today's standards, all controls on air handling units have been upgraded or replaced, operation of heat exchangers (plate type and shell and tube) used to make hot water for climate control and domestic purposes has been automated, etc. CCJ

Integrating renewables into the generation mix: Challenges and unknowns

The adverse impacts on powerplant performance and economics associated with injecting large amounts of renewable energy into the grid are of great concern to many owner/operators of conventional generating assets. Many industry events have covered this topic in recent months, but the first to hit it head-on was a one-day critical-issues workshop at the CTOTF's fall meeting in Reno, Nev, September 13.

Although the challenges of renewables integration were expected by most seasoned industry veterans, CTOTF Chair Robert G Kirn of TVA said that the speed at which intermittent renewable resources have penetrated certain markets, regions, and balancing authorities have resulted in grid security and plant operational issues that will require innovative solutions and extraordinary cooperative effort across non-traditional lines.

Speakers at "Integrating Renewables into the Generation Mix: Challenges and Unknowns" defined the principal elements of the challenge, and then proposed solutions—strategic, technological, operational, and regulatory. The challenges can be classified in broad terms this way:

- Existing generation resources must have more flexibility. Whether they can achieve that flexibility economically and without sacrificing other performance goals, such as safety, reliability, and efficiency, is another matter.
- Markets and balancing authorities must institute new measures to value, pay for, and/or reward dispatch at sub-hourly time scales—perhaps down to minutes.
- Costs of cycling generation resources must be more accurately assessed and accounted for.
- Grid issues respective of the magnitude and type of renewables connected vary dramatically across regions. Solutions may require regionally based approaches and levels of renewables based on operational characteristics versus renewable energy source goals.

The solutions, in turn, can be grouped into these broad categories:

Photos by Mark Severts

Meeting Chair John E Borsch, manager of California plant assets, Colorado Energy Management LLC

Jeffrey L Ceccarelli, senior VP energy supply, NV Energy

- Modify existing plants to operate more flexibly.
- Revise market-value and reward profiles for ramping, intra-hour dispatch, turndown, and other market products reflective of increased grid security requirements.
- Seek or demand greater regional cooperation among individual balancing authorities.
- Expand bulk and distributed energy-storage installations, which could offer greater operational flexibility at lower cost than traditional options.
- Improve cost allocation and compensation to grid resources for ancillary services.
- Revise interconnection standards to recognize and assign renewable owner/operators costs for incremental system security and for ancillary services required to accommodate the operating profiles of renewables.
- Seek a legislated "sunset" to renewable energy production tax credits (PTC), especially for wind, which would slow wind penetration and create a more level playing field with respect to economic dispatch.

Setting the stage. Perhaps as simply and as eloquently as possible, Kevin Geraghty, VP power generation, NV Energy, which worked closely with CTOTF to develop the workshop, opened the meeting by observing that electric utilities today must serve as a safety net—that is, take the "extra juice" from grid-connected distributed generation (DG) resources, including renewables, and fix problems when they occur.

The idea of utility service has changed, he said, from one where perhaps 10 outages per year at your house might be okay to one where even a blinking digital clock is not okay. NV Energy must meet a 25% Renewable Portfolio Standard (RPS) by 2025, one of the most demanding state statutes in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CTOTF's Kirn calls for national forum of stakeholders to address impacts of 'must take' renewables on electric system operations

In recent years, CTOTF has expanded its historic roundtable profile from strictly technical discussion of combustion turbines to include all plant systems and components, as well as critical support services. As the complexity of powerplant operations has continued to evolve, discussion roundtables such as high-voltage equipment, generators, environmental, regulatory compliance, and management programs have been added both to maintain a comprehensive technical overview and to better understand the impact of the deepening intricacies descending upon the energy industry. Given the wide scope and high potential impact of the mandated addition of renewable generation resources, the formulation and presentation of a proactive program specifically dedicated to their operational impacts is a natural and necessary extension.

The economics, operational characteristics, and environmental impact of renewables—particularly wind and solar—are increasingly the focus of objective debate as global warming studies and the combustion of fossil fuels are systematically reviewed. However, in the interim, little attention has been paid to the operational impacts of adding "must take" renewable generation assets to the transmission grid.

The burden of compensating for the abrupt generation swings and low capacity factors ultimately cascades onto conventional powerplants, most notably, combustion turbines. In recognition, CTOTF's Integrating Renewables Workshop was specifically designed to identify operational issues and to stimulate comprehensive national discussion. Although only lightly touched in this forum, but of direct relevance, future discussions should also include "smart grid" and "smart metering" given similar potential impacts.

Taking the addition of renewable generation resources as a given, the workshop gathered industry experts to systematically profile the unique operating characteristics of renewables, the challenges they pose to transmission operations, the new operating demands for existing conventional generation, and potential solutions—including new equipment designs and energy storage.

While successfully providing an over-arching profile of a generation sea-change that has the potential to fundamentally amend nearly every aspect of the electric power industry, the resulting number of questions greatly exceeded the number of answers. This leaves us, as a nation, with the ultimate questions of the "why, who, what, when, and where" do we go from here?

With the universal recognition that the availability of affordable electrical energy is fundamental to economic vitality, there must be credible and objective discussion in order to "get it right the first time"—technically, economically, and environmentally, near-term and long-term. At CTOTF, with its more than 150 member companies, our hope is that the Integrating Renewables Workshop will serve as spark for the extensive technical and objective discussion that must follow.

Robert G Kirn
Chairman, CTOTF

Robert G Kirn, *Senior Program Manager for Business Ventures, TVA*

Kirn's 35-year career in the electric power industry includes positions in engineering and in the management of construction and operation for multiple types of generating plants and power delivery systems at both regulated electric utilities and independent power producers. He has served as chairman of CTOTF since 2008.

the nation. Today the company ranks first nationally in installed solar energy capacity per person.

Jason Makansi, president, Pearl Street Inc, and executive director of the Coalition to Advance Renewable Energy through Bulk Storage (CAREBS), then framed out at the industry level the challenges that confront generation owner/operators. While many of the driving forces favoring renewable energy are well known—for example state RPSs, the "environmental gauntlet" facing coal-fired plants, and pending federal legislation that could escalate renewable energy penetration—many attendees were surprised to learn that from 60% to 90% of all generation interconnection requests in six independent system operator (ISO) and regional transmission organization (RTO) jurisdictions are renewable energy (mostly wind).

Another surprise to some: Large amounts of wind energy in certain balancing authorities and areas—including the Electric Reliability Council of Texas (Ercot), Bonneville Power Administration (BPA) in the Pacific Northwest, and the Midwest ISO—can drive market prices into negative territory because of the PTC subsidy.

Characteristics of this renewable resource important to any economic evaluation include the following: Wind-energy strength curves are opposite of electricity demand curves; availability of wind energy can shift dramatically in a few minutes; wind capacity factors rarely average more than 30%. Thus plants powered by gas turbines and coal are penalized by having to undergo deeper and more frequent cycling to "fill in" around intermittent wind.

Jason Makansi, president, Pearl Street Inc; executive director, CAREBS

Also of interest: Less than 10% of Ercot's total wind capacity is considered "available" during summer-day peaks. Plus, wind energy in PJM Interconnection is credited with only 13% of its capacity value during peak periods. And MISO representatives report that swings of up to nearly 2000 MW are common.

Makansi suggested four broad solutions options, adding that all ultimately would be deployed in some combination in regions affected by large-scale renewable energy penetration. The options:

- **Smart grid.** Enhanced wind monitoring, forecasting, and communications with grid operators, combined with demand side management (DSM).
- **Gas + wind.** Deeper and more fre-

Michael Roberts, managing director of power asset management and operations, Iberdrola Renewables

Stephen J Beuning, director of market operations, Xcel Energy Inc

'Solar power could crash Germany's grid'

That was the headline for an article posted on the website of Reed Business Information Ltd's magazine *New Scientist* October 28.

The article had a familiar ring: "Subsidies have encouraged German citizens and businesses to install solar panels and sell surplus electricity to the grid at a premium. Uptake has been so rapid that solar capacity could reach 30 GW, equal to the country's weekend power consumption, by the end of next year."

A spokesperson for DENA, the German Energy Agency, was reported as saying, "We need to cap the installation of new panels." The article also mentioned a warning by Stephan Koehler, the agency's chief executive—in an October interview with the *Berliner Zeitung*—that at the current rates of installation PV could trigger blackouts.

New Scientist reported that the German Solar Industry Federation rejected DENA's concerns. Its belief: Solar energy takes the pressure off high-voltage power lines because it usually is generated close to where it is used.

Whether you believe large quantities of solar power could crash a grid or you don't is not so important. What the German experience points to are the unintended consequences of widespread renewables development without adequate preparation. The impacts of intermittent renewables on grid operations and on the health of conventional generation assets are not well known anywhere on the globe and should be studied carefully before assuming RPS goals are achievable technically and economically.

Wind. A press release on the DENA website noted that the agency has just given the green light for research into the expansion of wind energy in Germany. This is the second part of organization's grid study to justify increasing energy supply from renewables to 30% of the kilowatt-hours sold by no later than 2025. Part 1 of the study was finalized in spring 2005.

Wind generation will be evaluated under technically difficult conditions—such as high winds, a lack of wind, and peak-load times. Grid impacts, realistic transmission distances, flexibility of conventional generation, role of energy storage, etc, all will be researched. Study assumes 20 GW of offshore wind and 28 GW of onshore wind; also, that the expansion of the EHV grid outlined in Part 1 of the study is completed in timely fashion.

quent cycling and dispatching of existing fossil assets, and the addition of more flexible gas-turbine-based assets.

- **Energy storage.** Build a new layer of bulk and distributed storage options, which offer greater flexibility than alternatives for meeting sub-hourly dispatch requirements.
- **Business as usual.** Run old fossil units into the ground.

Ultimately, all of these solution sets will be deployed in some combination for all regions affected by large-scale renewable energy penetration.

The advantages bulk energy storage offers are considerable, Makansi went on. Pumped hydroelectric storage (PHS) and compressed air energy storage (CAES) are both commercially available, *investible* options long on operating experience. They can move from idle to full load in less than 10 minutes; comfortably charge and discharge for two, six and even 12 hours; have no emissions (PHS) or a minimal emissions profile (CAES); and suffer less deterioration in cycle efficiency and emissions degradation than simple-cycle gas turbines or combined-cycle systems.

Most importantly, perhaps, PHS and CAES can function *both as load and generation,* making them ideal for ancillary services. Dozens of new PHS and CAES plants are being developed nationwide and regulations and policies at the state and federal levels are being shaped so that storage can be included as a viable asset class for grid operations.

Generating companies speak. Michael Roberts, managing director of power asset management and operations for Iberdrola Renewables Inc, Portland, Ore, the leading wind-energy producer worldwide, noted that his company designed a combined-cycle plant, Klamath Falls, specifically for daily cycling. Grid flexibility in the West is "being used up," he cautioned.

Although some point to the flexibility of hydroelectric plants for integrating wind energy, Roberts noted that,

Jonathan Hawkins, manager of advanced technology and strategy, PNM Resources

Adrian Pieniazek, director of market policy for the Ercot region, NRG Texas LLC

CTOTF NVEnergy

Renewable energy: The ultimate balancing act

The art of balancing is nothing new to energy utilities. We continually balance the needs of customers with environmental sensitivities, with regulatory oversight, and with shareholder interests. However, our well-honed traditional equilibrium skills will need to be razor-sharp in this exciting era of growing renewable-energy portfolios.

Balance is especially important in the Desert Southwest, and specifically in the state of Nevada, as we need to strategically assess the benefits of utilizing different types, sizes, and varieties of renewable-energy projects that will benefit customers. NV Energy, for example, has 23 geothermal projects, eight solar projects, five biomass projects, five small-hydro projects, two large wind projects and one waste-heat-recovery project that are either in production or under development. No project in our current 1.2-GW renewable energy portfolio is easy, but each one will benefit our customers, the environment, and our shareholders.

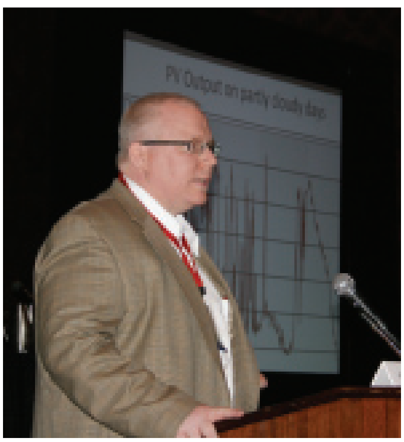
While the benefits seem so apparent, the development of renewable projects is not as easy as we might expect. Balancing the needs of all stakeholders in the siting process is difficult. A state mandate to grow our customer's renewable-energy supply does not tip the scales in the favor of developers and proponents as many might expect. Careful planning and managing the opposition by groups that oppose all forms of utility-scale energy projects is a balancing act without a safety net.

One of the most significant balance-beam issues, of course, relates to legislated requirements for Renewable Portfolio Standards (RPS) and their related cost impacts. While I firmly believe that the cost of renewable energy will become more and more competitive, most electricity customers throughout the nation don't fully appreciate the impact that "free wind" and "free sunshine" will have on their individual utility bills.

Obviously, there is a very fine line that companies such as ours must walk—to make sure customers are prepared for higher renewable-energy costs—without our company somehow being perceived as being resistant to renewable-energy growth. Again, another balancing act must be performed.

Other significant situations that require careful analysis and astute balancing skills can be summed up in these questions:

- How much of our renewable energy portfolio should be secured through power-purchase agreements and how much should we build ourselves?
- What is the ideal mixture of wind energy, geothermal energy, solar thermal, solar photovoltaic, biomass, waste heat recovery, and small hydro for our customers and service territory?
- Considering the fact that we have an increasing RPS to meet and that many renewable projects can be delayed, cancelled, or have under-production problems, how much renewable energy should we over-subscribe to assure that we meet the annual stair-stepping RPS requirements?
- Should we take a leadership or a "fast-follower" approach to cutting-edge renewable-energy designs for such opportunities as solar thermal projects with storage capacity, or new methods for integrating solar thermal into our combined-cycle natural gas plants?



- How do we resolve the "chicken and the egg" question about when to build transmission lines to accommodate renewables.
- What is the proper balance between utility-scale renewable-energy projects and home solar or wind applications for individual customers?

Even after we master the issues associated with these types of questions, the largest elephant in the room may be the unanticipated consequences of injecting large amounts of intermittent energy into our local systems or our regional grid. "Balance" will take on a deeper meaning. How can we maintain system balance without cannibalizing our traditional generating assets and reducing efficiencies?

In other words, if we start changing the role of base-load units to become renewable-energy responsive load-following assets, what will that do to our maintenance costs? What will be the impact to the plant's life cycle? Will there be significant losses in operational efficiency? Are there plant safety implications?

The solutions to these and other questions will not come easy. It will take a combination of many solutions to resolve this challenge. And, it will require cooperation, partnerships, and concessions as an industry. The solutions undoubtedly include:

- Modifying our existing generation resources to be more flexible to renewable intermittency;
- Seeking greater regional cooperation among individual balancing authorities; and
- Implementing smart-grid technologies—still in the incubation stage—to facilitate seamless integration of renewables in the future.

Albert Einstein once said that "life is like riding a bicycle—to keep your balance, you must keep moving." Such is the case with today's unbalanced challenges surrounding renewable energy. We simply "must keep moving."

Kevin Geraghty
VP Generation, NV Energy

at least in the Pacific Northwest, they are usually under ecological restrictions to manage fish life. He also noted that no formal market exists for flexibility, although BPA is headed that way.

While Roberts urged the development of flexible energy products, he conceded that the contractual obligations to meet such products would be "a mess," the maintenance component of the costs of cycling units is difficult to quantify, and complex computer modeling is necessary—that is, at once user-friendly to traders, operators, and forecasters. He asked the audience, what is the "surcharge" for the necessary flexibility? Growth in wind power makes life difficult for grid managers, he stressed.

Iberdrola's observations as an independent generator were contrasted somewhat by those of Stephen Beuning, director of market operations for Xcel Energy, the top wind provider in the nation. He believes that renewable energy to date hasn't been required to dispatch, but future systems will be, and that fast intra-hour dispatch will mitigate the balancing-area challenge and provide market signals as well.

To do this most effectively, Beuning suggested to utilities with their own balancing authorities in the West to work more on a regional basis. Today, gas turbines and other powerplants must be committed to accommodating wind energy.

As chair of the Western Electric Coordinating Committee's (WECC) Seams Issues Subcommittee, Beuning was able to offer insights into regional activities. WECC, he noted, has only limited congestion management procedures and only six transmission paths available to manage congestion.

WECC's "efficient dispatch toolkit" includes an enhanced curtailment calculator for the entire footprint and an energy imbalance market. The RTO is currently evaluating a process called "virtual consolidation" and is expected to complete a benefit/cost analysis by the middle of next year. With wind resources projected to increase beyond 50,000 MW by 2019 in the Western Interconnection, variability impacts must be addressed now.

PNM Resources, according to Jonathan Hawkins, manager of advanced technology and strategy, plans to solve integration problems at the distribution level, providing a firm, dispatchable renewable resource by adding large scale batteries and smart-grid technology. Beyond 20% renewable energy penetration, community energy storage systems—neighborhood units with the look and feel of those "green" transformer boxes—may be investigated.

The view from grid-side. Echoing a comment made by several presenters, Clyde Loutan, a senior advisor in the California ISO's Market and Infrastructure Div, said that the West does not have much inertia in its grid, unlike the eastern part of the country. He also mentioned hydro resources, but "what about a bad hydro year?" It bears remembering that a very poor hydro year helped precipitate California's electricity crisis a decade ago, and that ultimately forced the governor out of office.

Astonishingly, 18,000 MW of thermal generation will be retired or repowered in the next 10 years in California, while 20,000 MW of wind and solar is expected to be added. Currently, the state faces separate challenges balancing wind energy and solar resources. Almost all of the generating resources in the state are only capable of 20-MW/min ramp rates, or less.

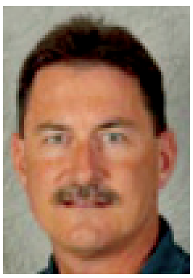
In addition to the day-ahead and hour-ahead schedules, the system may need the capability to dispatch units on a five-minute basis, a significant departure from current practice. However, Loutan suggested that, up to a certain point, deviations in supply and load can be "picked up" and managed in frequency regulation—one of several so-called ancillary services. To manage the impacts of the state's demanding

Panelists discussing issues included speakers, top plant executives

Jeff Chartier, *Combustion Turbine Manager, Tri-State Generation & Transmission Assn Inc*

Chartier has years of gas turbine experience on a wide range of General Electric and Westinghouse machines. He currently manages fleet-wide O&M and capital improvements for 10 GTs at four plants.

Steve Hedge, *General Manager, W A Parish Generating Station, NRG Energy Inc*



Hedge recently celebrated his 25th anniversary in the electric power business, where he has worked as an engineer, plant manager, and general manager at conventional steam, combined-cycle, and peaking plants.

Scott Takinen, *Plant Manager, West Phoenix Generating Station, Arizona Public Service Co*

Takinen has more than three decades of experience at APS in the engineering and management of nuclear, coal-fired steam, and combined-cycle generating plants. Currently leads a team of 59 employees at West Phoenix, providing both power and ancillary services. Another responsibility: Generic safety and environmental issues across the company's gas/oil-fired plants.

Ozzie L Lomax, PMP, *Manager of Gas & Renewable Generation, AmerenUE*

Lomax manages 15 gas-fired powerplants (3000 MW) and the "Methane to Megawatts" facility under construction. Strategic planning and O&M budgeting for the Power Operations Div are among his responsibilities. Before joining Ameren nine years ago, Lomax spent 22 years at Kansas City Power & Light Co in various leadership and engineering positions. His sits on the advisory boards for two colleges incorporated into Southern Illinois Univ.

Michael Rutledge, *Manager of Plant Technical Support, Salt River Project*

Rutledge's group supports all generating facilities and other company departments with a broad spectrum of specialized technical know-how. He is a respected three-decade industry veteran.

RPS by 2020, CalISO and others are looking at integrating storage into supply scenarios.

Although employed by NRG Texas LLC, Adrian Pieniazak, director of market policy for Ercot, gave an Ercot/IPP perspective on wind integration. In Texas, upwards of 41,000 MW of wind could be interconnected in the coming years. One of his eye-opening stats: Last August 16, peak-hour load was 64,805 MW; wind output averaged only 650 MW, from a resource base totaling more than10,000 MW.

Pieniazak started by reminding the audience that FERC has no jurisdiction in Texas. Wind energy is suffering in Texas not only because of curtailments, but because curtailed wind resources are then limited in how fast they are allowed back onto the grid. Ercot now requires new wind turbine facilities to provide their own voltage support; some machines must be retrofitted as well.

Ercot also modified regulation and added more "non-spin" at 30-min intervals but may have to go to a 15-min non-spin regulation product. He noted that Ercot as a whole "hasn't done well on ancillary services cost allocation." Pieniazak focused attention on Texas' Competitive Renewable Energy Zone (CREZ) transmission line build-out. CREZ will help with integration long term, but the first lines won't be in operation until after 2012.

On the solutions side, Pieniazak believes that newer-model wind turbine/generators can provide frequency control and be placed on AGC just like gas turbines. Nevertheless, the high-wind-week projections for year 2013 look "really scary," he said.

A trio of speakers from NV Energy—Richard Salgo, director of electric systems control operations; Gary Smith, director of smart technologies; and Dariusz Rekowski, director of generation O&M, gave a "grid operator" perspective on integration issues. Most of the presentation was a well-needed refresher on balancing areas.

A recurring theme was the quality of spinning reserves versus the quantity. Nighttime minimum load in northern Nevada can be as low as 750 MW, which poses operational challenges for conventional generation assets because half that demand, possibly more, is under contract as "must-take" renewable power. This obviously limits the "range of motion" of generating units that can't be taken offline.

Part of the solution will come from the utility's Advanced Service Delivery (ASD) program, demand response management anchored by smart meters, and customer "ownership" of their energy usage. But NV Energy's generating assets still will have to make sacrifices in terms of increased cycling, faster ramp rates, and lower-load operation, which negatively affect performance. Lower efficiency and higher fuel consumption and CO_2 emissions are among the impacts. Consequences for NV Energy and its customers will be incrementally higher fossil-plant O&M costs and increased investment in units that will generate fewer megawatt-hours.

Enter storage. Bob Kraft, CEO and president, Energy Storage & Power LLC (ES&P), Bridgewater, NJ, told the audience that his firm is evaluating CAES systems up to 460 MW in size for greenfield sites, as well as the retrofit of existing F-class turbine plants for this service.

Other features of a modern CAES plant, compared to the pioneering version demonstrated at the McIntosh facility in Andalusia, Ala, include these: three-minute bottoming cycle startup from a warm condition; use of commercially available components, not custom equipment; state-of-the-art combustor technology; and split system with multiple compressors and expanders to add flexibility.

According to Kraft, a "CAES 2" plant can ramp at rates up to 28 MW/sec. Another interesting offering from ES&P is a humid-air turbine, which regains cold-day performance on a hot day and promises a 13% power boost for today's standard combined-cycle plant at less than $350/kW.

Flex machines. The new capabilities being built into today's gas turbines was amplified by Bruce Rising, strategic business manager, Siemens Energy. Rising claimed that a Siemens simple-cycle Flex-Plant™ 10 can reach 150 MW in 10 minutes, the 150-MW combined-cycle Flex-Plant™ 30 in 30 minutes. Advanced power diagnostics and an integrated fuel-gas characterization system are features that will enable such plants to better handle deep cycling and dispatch. Rising reiterated the unintended consequence of fast ramping: Reduced efficiency of environmental controls.

A planner's perspective. Victor Niemeyer, technical executive for EPRI's Climate Program, connected wind integration to global climate change issues. He began by saying in the low-carbon future, coal "is toast," which made even this natural-gas-oriented audience wince. Of course, what he meant was that, long-term, carbon is a factor even without an imminent federal policy goal for carbon. At $100/MWh, he said, wind could displace all of the nation's coal.

While that may make wind enthusiasts cheer, another observation was more sobering: The idea that wind from one region will compensate for wind in another is not true. Sometimes there is no wind over a broad area. Niemeyer pointed to some modeling and analysis work conducted over a seven-state region (the Dakotas, Minnesota, Iowa, Missouri, Kansas, and Nebraska) which showed that low wind output can persist for extended periods.

Niemeyer concluded with these three points: Adding transmission enables greater utilization of wind (although "lots of line-miles are necessary"), cost of wind delivered to load is much higher than the simple cost of generation, and the "anti-correlation" of wind with load and the need for new interregional transmission "greatly limits" the fraction of coal generation displaced by wind in a de-carbonized future.

Presentations by Thomas Mastronarde, Gemma Power Systems LLC, Glastonbury, Ct, on integrating combined-cycle heat-recovery steam generators with solar thermal, and by Steve Gressler, Structural Integrity Associates Inc, San Jose, Calif, on material considerations for equipment under increased cyclic duress, rounded out the day.

Panel discussion. Some of the more salient points gleaned from the workshop's two panel discussions:

- In Ercot, municipal utilities with a rate base are the only ones that can build and finance peakers and "flexible resources."
- Ercot rules forcing wind turbine plants to retrofit reactive power and voltage control are under appeal by the Texas Public Utility Commission.
- Interconnection standards for wind machines were proposed by the Cal-ISO for all non-synchronous units, but were rejected by FERC.
- CAES-based storage has natural reactive-power capabilities.
- ISOs/RTOs have learned a great deal about committing resources to manage wind penetration, but industry participants must get beyond long-term averages because forecasted operations and actual operations can be vastly different.
- Owner/operators need to rethink maintenance strategies when a nominal 650-MW fossil unit is being replaced by, say, a half-dozen generators at smaller facilities, not to mention hundreds of wind generators hanging hundreds of feet in the air.
- The $6-billion cost for CREZ in Texas is being socialized across the Ercot load, but industrial and consumer groups are fighting the policy. California is also considering CREZ-type approaches to add transmission infrastructure that enables wind.

Overview

Wind potential and economics

Victor Niemeyer, the technical executive for EPRI's climate change program, offered an objective view of wind drivers and economics. It was wind from 30,000 ft, quite unlike most other presentations at the workshop, which focused on specific ways to accommodate the variable nature of wind and to move the electricity it produces from point A to point B.

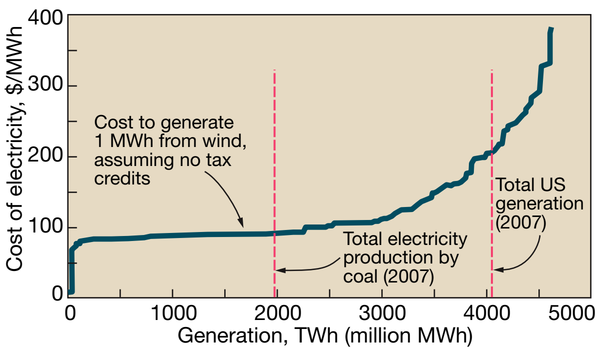
He said that if the federal government were to write into law a national policy to curb CO_2 emissions below current levels, the legislation would likely initiate a competition to replace existing coal. Renewables, nuclear, and carbon capture and storage (CCS) would be among the high-profile solutions. Passage of climate legislation, Niemeyer continued, would initiate a "voyage of discovery" leading to an energy paradigm for the future that is much different than exists today.

Wind resource potential is huge, he said, exceeding half of the nation's current electric needs at \$90-\$100/MWh, and possibly exceeding current generation from coal (Fig 1). Unsubsidized wind, the economist added, is competitive with \$8/million Btu gas on a pure energy basis.

Niemeyer qualified his remarks by saying wind potential is adversely impacted by:

- Long periods of calm with no output over large geographic areas—swaths of real estate that may extend over several states.
- Rapid changes in wind generation over relatively short periods of time—an hour or less in some cases.
- "Anti-correlation" of wind with load.
- The cost/ability to permit new transmission needed to move wind energy to consumers.

The economist added that while he was not expecting climate legislation anytime soon, because it could happen might discourage power generators from considering coal as a viable option for future capacity. One of his slides plotted the CO_2 emissions reductions required to satisfy several pieces of legislation introduced in the last several years. A couple of the laws proposed would require that CO_2 emissions be halved from 2005 levels within 25 years, and cut to 80% below historic levels by 2050. Access Niemeyer's presentation at www.integrating-renewables.org.



1. Wind resource potential is huge, exceeding half of the nation's current electric needs at \$90-\$100/MWh, roughly double the average cost of coal-based electricity

Next came a few numbers to illustrate the magnitude of the challenge associated with curtailing CO_2 emissions—and the cost. The electric sector, Niemeyer said, produced 39% of the country's CO_2 (and one third of its total greenhouse-gas emissions) in 2006; 83% of the industry's CO_2 was emitted from coal-fired plants burning fuel at an average cost of \$2.50/million Btu.

He believes that any cap-and-trade legislation seeking to cut emissions well below current levels would include incentives for new generation to back out coal; also, the national CO_2 "price" would be whatever it takes to displace existing coal.

Wind potential. EPRI engaged AWS Truepower LLC, Albany, NY, to get a comprehensive assessment of wind resource potential. It identified more than 5000 viable utility-scale (100 MW minimum) wind-farm sites nationwide based on actual hourly meteorology from 1997-2008, assuming installation of 1.5-MW turbines.

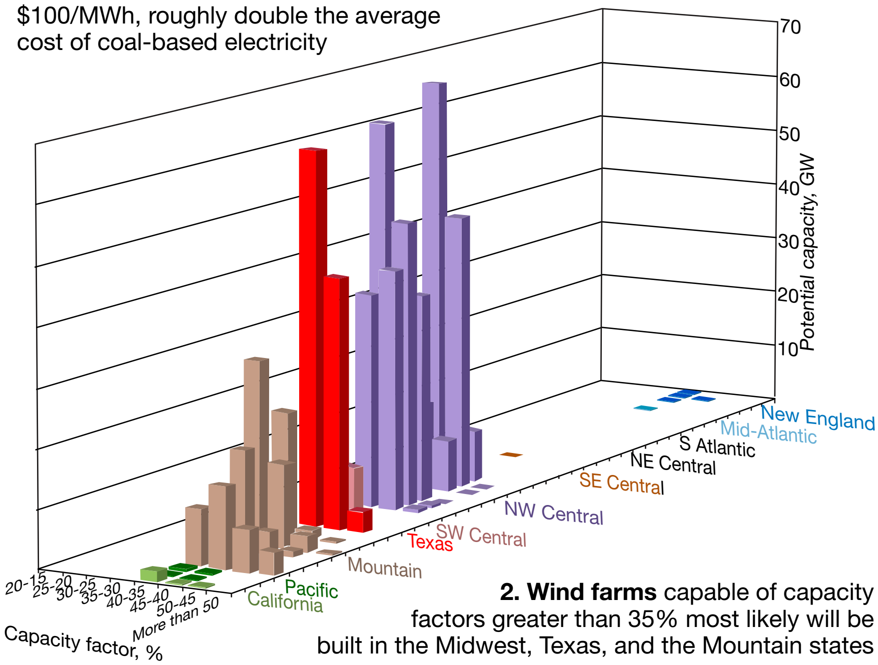
Variables such as distance to the grid, terrain/wake effects, and exclusion areas were factored into the analysis. Fig 2 shows where the wind farms (capacity factors greater than 35%) would most likely be located.

An example analysis conducted for the North West Central (NWC) region is instructive, illustrating key points regarding the behavior of wind. About half the nation's wind potential exists in this seven-state area (Minnesota, North and South Dakota, Nebraska, Iowa, Missouri, and Kansas). However, regional demand would be largely satisfied with less than 10% of that amount were it built. "Use it or move it," Niemeyer said. Easier said than done: The regional grid can't handle anywhere near the amount of wind power that could be produced.

More wind than load produces a local surplus that must be "spilled" if it can't be exported. If you must spill, capacity factor of your wind turbines decreases and your pro forma takes a hit. Given adequate wind resources, the challenge is to match market needs.

The EPRI study was based on the following facts and assumptions: (1) actual state hourly load data for 2007 from Energy Velocity LLC, Boulder, Colo; (2) correlation of energy consumption with meteorological data to quantify the impact new wind generation would have on regional demand; (3) an additional 50 GW of new wind capacity installed in the region at qualified sites offering the highest capacity factors.

Figs 3-5 offer grid operators and power generators unfamiliar with



2. Wind farms capable of capacity factors greater than 35% most likely will be built in the Midwest, Texas, and the Mountain states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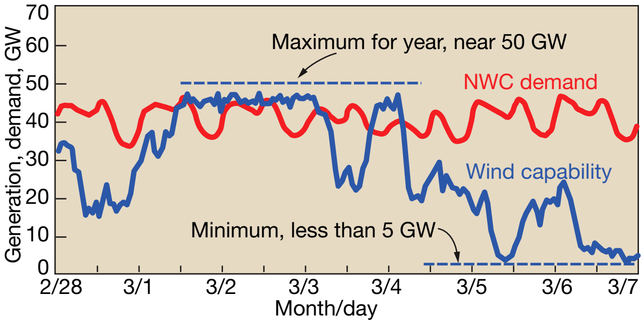
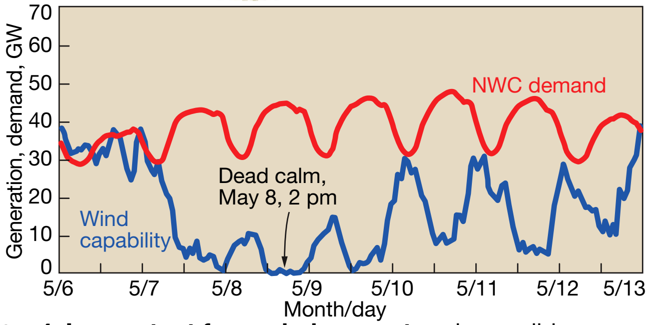


3. Variability in wind production is evidenced by nearly 50 GW of capacity early in the week, less than 5 GW at week's end



4. Low output from wind generators is possible over long periods

wind's idiosyncrasies a short course on its variability and electric system impacts. The NWC time series from Feb 28, 2007 through March 7 (Fig 3) reflects the week of highest wind output for the 2007 simulation. Keep in mind that this simulation includes the 50-GW addition to the wind capacity existing in the region.

The wind curve illustrates the variability in electric production experienced. Dispatchable capacity early in the week is close to 50 GW as a cold front moves through the region, and less than 5 GW at the end of the week after the front has passed. "Wind comes and goes," Niemeyer said, putting up the next slide in the series.

Fig 4, for May 5-12, 2007, illustrates a prolonged period of low wind; a dead calm is experienced the afternoon of May 8. The EPRI executive said many people believe that although wind might not be blowing at any given point in the region, it is blowing elsewhere. That's not necessarily true, he continued, showing a national weather chart for May 8 that revealed a stall extending over more than just NWC.

The time series from Aug 9-16, 2007 illustrates a typical summer pattern in NWC (Fig 5). Note that the wind pattern is more consistent day to day in summer than it is in winter (refer back to Fig 3). More importantly, the chart clearly shows the anti-correlation of wind with load—that is, wind production is highest when demand is lowest. Looking ahead, conventional assets backing-up wind will require the ability to ramp up and down quickly to maintain the continuous balance between load and generation needed for a reliable power system.

Niemeyer summed up his thoughts with these three points:

- Adding transmission enables greater utilization of wind resources.
- The cost of wind delivered to load is much higher than the simple cost of generation.
- Anti-correlation with load and the need for new interregional transmission capacity limit the amount of existing coal-based generation that wind can displace in a decarbonized electric future.

How much will wind cost? Niemeyer answered this question based on AWS TruePower's national wind energy supply curves and EPRI's estimates of generation and transmission asset costs. The exercise was to estimate the cost of producing and delivering 1000 TWh, or about 50% of the energy supplied by coal-fired powerplants (Fig 6).

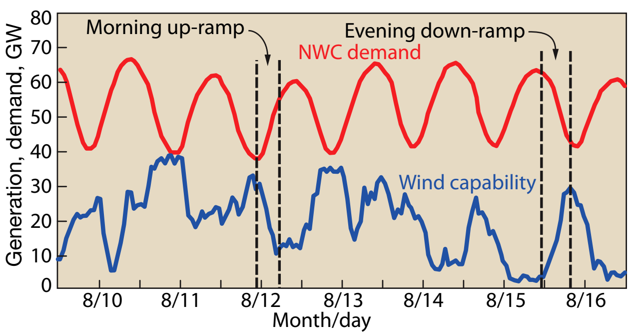
The answer: It would take about 175,000 1.5-MW wind turbines to accomplish the goal at a total installed cost of about $650 billion. Delivery of the power produced would require about 13,000 line-miles of extra-high-voltage (800 kV dc) transmission lines at a cost of approximately $50 billion. Niemeyer mentioned that the biggest question is not about the cost of transmission, but rather if you can construct it at all.

Referring to the chart, he said that delivered cost jumps up right away (point A), because you must integrate the new capacity with the existing grid. It is about $450/kW for *induced* transmission associated with backing up wind, Niemeyer continued. If you add a couple of wind turbines, there is no associated grid cost impact because you can squeeze them onto the existing infrastructure.

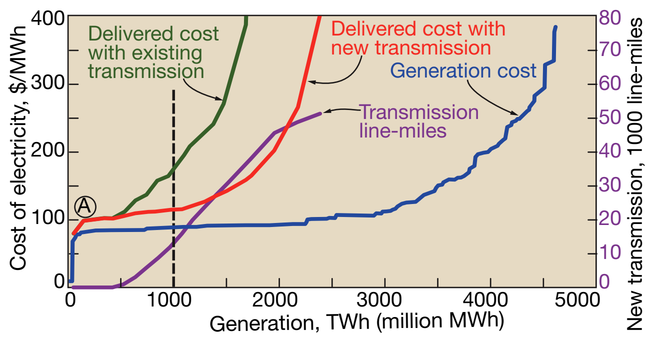
But the installation of wind farms rated in the hundreds of megawatts require upgrades to transmission assets. And the further wind resources are located away from the load, the higher the voltage must be to reduce line losses. The curves of delivered cost are steep, he added, because wind does not line up with load (anti-correlation)

Dr Victor Niemeyer, *Technical Executive for Global Climate Change, Electric Power Research Institute*

An economist by education, Niemeyer conducts research to help energy companies manage the risks from global climate change. In particular, he assesses the cost and competitive-market implications of potential climate-management policies.



5. Anti-correlation of wind and demand is clearly in evidence for this week in summer. Wind production is highest when demand is lowest and vice versa



6. Addition of about 175,000, 1.5-MW wind turbines could displace half the coal-fired generation at a cost of about $700 billion, including transmission and capacity factors for wind turbines decrease as you add more and more wind.

"The bottom line is that the country has a vast potential wind resource, but there are fundamental forces that limit how much we can use," Niemeyer said in his summary remarks. The biggest is that wind output just does not line up that well with loads. The anti-correlation effect clobbers the economics of wind once you start to generate more than 10% to 20% of total electricity demand—depending on whether or not a large amount of interregional high-capacity transmission can be built.

The climate-change expert closed with this thought: Wind can play a strong role in a low-carbon electric future, but it will not be a dominant role."

Grid impacts

How intermittent renewables impact CalISO

"Pretty challenging times," said Clyde Loutan as he began his presentation on how the CalISO works today and what changes probably will be necessary to accommodate the state's aggressive 33% RPS by 2020. An intermediate step: 20% of California's kilowatt-hours must come from renewable resources by 2012—a goal most other RPS states have established for 2020. California policy also calls for emissions of greenhouse gases to be at 1990 levels by 2020.

The CalISO controls about 80% of the state's load, which was about 50.2 GW during the peak year of 2006.

Specific operational challenges faced by CalISO over the next 10 years include the following:

- Increased supply volatility. Expectation is that more than 20 GW of wind and solar capacity will come on line by 2020 to meet state policy goals.
- Uncertainty surrounding thermal resources. Approximately 18 GW of thermal generation will be retired or repowered in the next 10 years.
- Less predictable load patterns. Changes to current load patterns are expected as reliance on distributed generation and electric vehicles increases.
- Changing revenue patterns. Decreasing marginal prices and changes to the dispatch of generation resources will force stakeholders to re-evaluate business plans.

Loutan had three slides to illustrate how intermittent renewables impact grid operations. Fig 7 was developed from wind production data for April 2009. Each line tracks wind generation for one day that month and shows how difficult it is to predict with accuracy the production of wind resources in the day-ahead and hour-ahead timeframes.

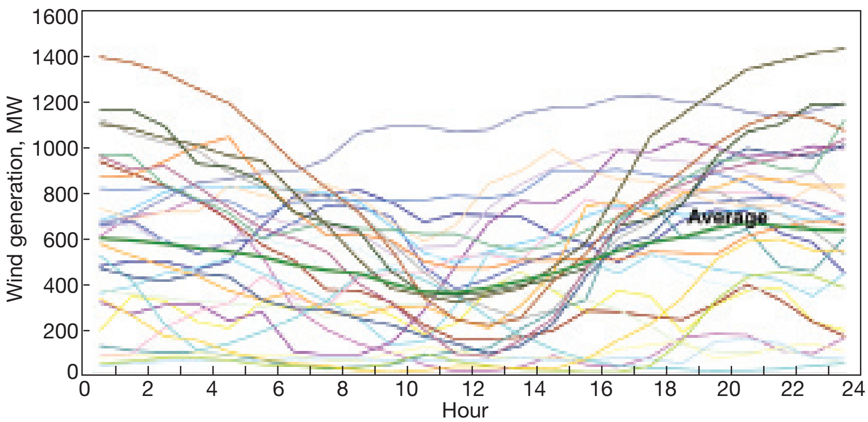
The variability of wind and solar are presented together in Fig 8, actual data for last June 24 (a cloudy day) recorded for a 150-MW wind farm and a 24-MW solar PV field. "How would you balance these resources in real time?" Loutan asked the workshop participants.

Next, he showed the group how dramatically the dispatch of conventional resources would change with significant contributions of solar and wind power (Fig 9). Before intermittent renewables, generation resources would be dispatched to follow load, the top curve. But when solar and wind are added to the mix, dispatch of conventional resources would have to follow the red curve.

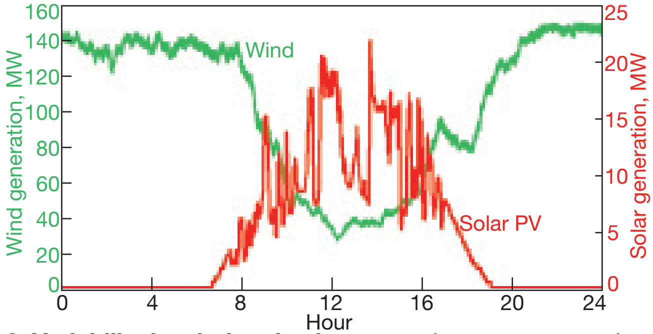
The CalISO has roughly 60,000 MW of capacity at its disposal today, including 5000 MW of dynamic schedule. Ramps up and down will be one of the biggest challenges for conventional assets going forward, Loutan told the group.

Fig 10 shows current ramp rates for the ISO's generating units. Note that relatively few assets can ramp at 20 MW/min or more, and most of those are hydro. The grid expert stated that on a typical summer weekday, between 8 and 10 am, load can increase by about 4000 MW an hour.

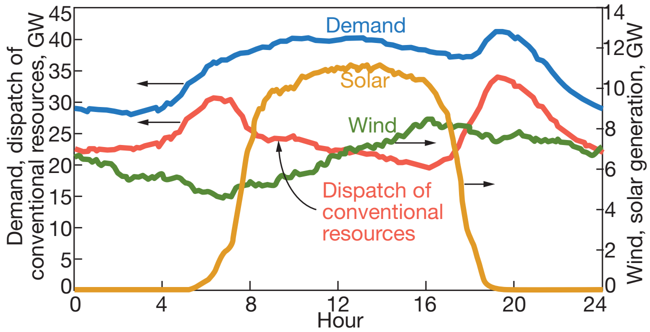
Today, the CalISO can meet this hourly ramp requirement, mitigate



7. Wind generation can vary dramatically from day to day. Each curve above illustrates the wind generation profile for one day in April 2009. Knowing what to expect from wind when lining up resources a day ahead is challenging for grid operators like the CalISO, which developed this chart based on its system data



8. Variability in wind and solar generation are compared for a cloudy California day. The solar PV field is rated 24 MW, the wind farm 150 MW



9. Dispatch of conventional resources does not follow the typical load curve when significant amounts of intermittent renewables are injected into the grid unexpected intra-hour variability, and comply with control performance standards with a combined ramp rate of 60 to 100 MW/min. However, to meet the 33% RPS, technical studies show ramp rates may triple, which is not possible for the ISO's conventional generation as configured today. Loutan thinks the need for flexible conventional generation going forward cannot be overstated.

Perhaps the most valuable part of the presentation for many in the room who had spent their careers managing generation assets was Loutan's description of how the CalISO works. This was important so all could grasp the challenge grid operators would face if too much intermittent renewables capacity were added before existing infrastructure was upgraded or replaced to accommodate the wind and solar generation.

Referring to Fig 11, note that grid operators begin lining up available generating assets a day before they are needed by issuing a "day-ahead schedule" for each hour of the next operating day to meet expected hourly demand (blue). The day-ahead market closes at 10 am the day prior to the operating day.

A mixture of extremely long-start units (those requiring more than 18 hours to start), long-start (between five and 18 hours), medium-start (between two and five hours), short-start (less than two hours), and fast-start (less than 10 minutes) resources are lined up in "economic order" to serve load at lowest cost to consumers.

Generation requirements are adjusted continually based on forecast revisions. The green line shows the hour-ahead adjustment needed based on the revised hour-ahead demand forecast. The short brown arrow between the two horizontal line segments represents capacity that, in this case, must be added to meet the load expected.

Currently, the CalISO interchange schedules and self-scheduled generation are changed from one hour to the next over a 20-min ramp period beginning 10 minutes before the hour ends.

On a more granular scale, every five minutes, the CalISO economically dispatches its generation fleet to follow the expected load five minutes ahead of time. In the diagram, observe that "load following," or the five-minute dispatch, is the difference between the hour-ahead curve and the red line defining current requirements every five minutes. Asset flexibility is especially important for load following.

To illustrate how challenging load following might become under an aggressive RPS, Loutan offered this example: A fast-moving cloud bank can knock out a 500-MW PV field within five to eight minutes. It's unlikely such an anomaly could be completely accommodated with generation resources available to the system because of ramp constraints.

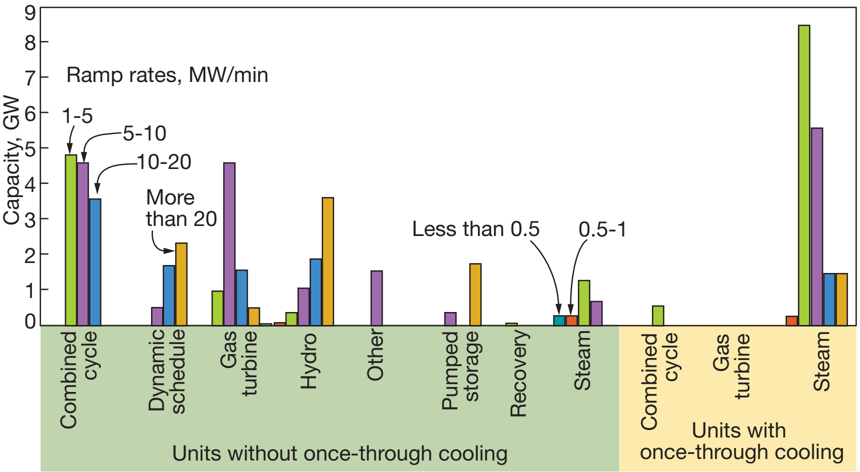
Additional support through dynamic schedules from a neighboring balance area, load reduction (via a demand-side management solution), and storage devices might all be necessary to balance the system with a high penetration of renewables generation.

The black curve at the top of the chart represents the actual load demand, which also corresponds to the total generation requirement. Regulation, defined here as the difference between generation and load in real time (so-called "imbalance"), is not dispatched through the CalISO's market software.

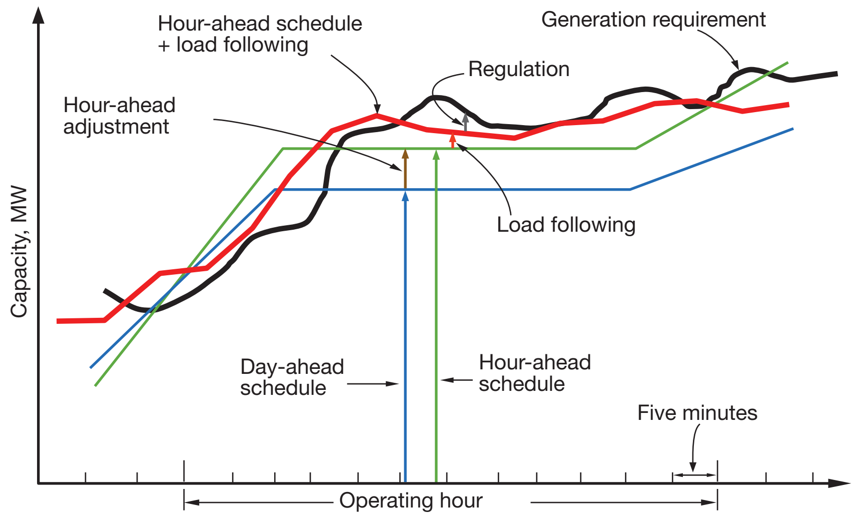
Rather, it is dispatched through the CalISO's energy management system every four seconds to correct for deviations in system frequency and deviations from interchange schedules with neighboring balancing authorities.

With the ISO primer putting everyone in the room on the same page, so to speak, Loutan summarized the results of a study the CalISO conducted to identify the operational requirements and resource options needed to operate its grid reliably under the 2012 20% RPS and the 2020 33% RPS. Another objective of the study was to provide information required by other stakeholders—including state agencies, market participants, etc—for decision-making.

Loutan began by identifying the



10. Ramp rates for CalSO generating assets today may not meet the grid's needs once the wind and solar generating facilities required to meet the 2020 33% RPS are up and running



11. Fleet operating flexibility is critical for accommodating the supply variability of intermittent renewables. Think for a moment about the challenges facing operators in this five-minute dispatch market where a 500-MW PV facility can potentially go dark within that time increment because of a rapidly moving cloud bank. This is not the same as losing a 500-MW combined-cycle plant because the impact on the system is different and the response to the lost generation would be different

Clyde Loutan, PE, *Senior Advisor, California Independent System Operator Corp*

Loutan, who was the principal investigator for the ISO's 2007 renewable-resource integration study, focuses on power-system operational performance. Previously he worked at Pacific Gas & Electric Co in real-time system operations, transmission planning, and high-voltage protection. Loutan has a Master's Degree in Electrical Engineering from Howard University and is a senior member of IEEE.

renewable portfolios assumed for the study (Table 1). Then he revealed the expected increase in regulation and load-following capacity requirements (within the hour) to meet those portfolios (Table 2). Note that in 2006, load was the only significant variable; for 2012 the variables primarily are load and wind, so capacity requirements increase significantly; in 2020 the variables will be load, wind, and solar, requiring a doubling of the 2012 requirements. Detailed study results were presented for the summer; however, spring, fall, and winter requirements are available at www.integrating-renewables.org.

Stand back for a moment and think about the variability that might have to be accommodated by the grid for the cases defined in the tables. Example: What if 10,000 MW of wind is forecast in the day-ahead timeframe and a substantial amount does not materialize during the operating hour? This scenario can create significant operational challenges—such as the ability to commit resources with the ramping flexibility to meet real-time variability.

As part of the study, CalISO investigated how operation of the combined cycles on its system would be impacted by the additional solar and wind generation assumed for the 2012 case compared to the baseline 2006 case. Results (annual basis) are presented in Table 3.

Loutan summarized the operational impacts of intermittent renewables, as defined in the study, this way:

- Increased frequency and magnitude of generating-unit ramps across various timeframes (minutes, hours).
- Increased load-following (up and down) requirements to accommodate intra-hourly deviations from hourly schedules, possibly requiring additional reserves.
- Increased regulation (up and down) to accommodate minute-by-minute requirements within 5-min dispatch intervals.
- Increased frequency and magnitude of over-generation conditions (minutes, hours).

Two additional considerations for the CalISO, the grid expert added, are these:

- The large difference in generating requirements in going from minimum load to peak load in the same day could be about 25,000 MW. This difference could increase depending on the production levels of variable generation.
- The grid must have sufficient inertia and frequency response should a major generation asset trip offline unexpectedly. In the Western Interconnection today, the loss of a large generating facility results in post-contingency frequency dropping to its minimum level within about eight seconds and governor response stabilizing the system in about 30 seconds. High levels of renewables penetration can impact this response if proper measures are not put in place.

CalISO is actively pursuing operational and market enhancements to support renewables integration, Loutan said. The list of valued operational enhancements includes the following:

- More accurate wind and solar forecasting tools—day ahead to real time.
- Over-generation mitigation procedures.
- More sophisticated grid monitoring systems.
- Higher degree of coordination with neighboring balance areas.
- Generation interconnection standards.
- Pilot/demonstration projects to assess the value of new technologies—including bulk energy storage, synchrophasors, demand response.

Market enhancements valued:

- New market products; changes to market rules.
- Increased regulation and reserve requirements.
- More sophisticated day-ahead unit commitment algorithms.

Summing up, Loutan segregated the resources required for renewables integration into three buckets: generation, storage, and demand response. Characteristics of the generation portfolio would include quick-start units, fast-ramp capability, wide operating range (especially the ability to back way down in load without exceeding emissions limits), and regulation capability.

Storage assets should enable the balancing authority to shift energy from off-peak to on-peak, mitigate over-generation, and provide voltage support and regulation. Demand response should be capable of frequency correction, provide rapid response to gaps in wind energy production, respond quickly to ISO dispatches, and be able to distinguish between loads that are price sensitive and those that are not.

1. Renewable portfolios (MW) assumed in the CalISO study

Reference case	Biogas/biomass	Geothermal	Small hydro	Solar	Wind
2006 actual	701	1101	614	420	2648
2012 20% RPS	701	2341	614	2246	6688
2020 33% RPS	1409	2598	680	12,334*	11,291

* Solar thermal, 6902 MW; PV, 5432 MW

2. Regulation and load-following capacity requirements (MW) in summer

Requirement	2006 actual	2012 20% RPS	2020 33% RPS
Regulation, up	277	502	1150
Regulation, down	-382	-569	-1112
Load following, up	2292	3207	6797
Load following, down	-2246	-3275	-6793

3. Comparing combined-cycle operation for the 2006 and 2012 cases

Parameter	2012 20% RPS	No new wind, solar since 2006	Change, %
No. of starts	3362	2492	35
On-peak energy, TWh	32.4	36.3	-11
Off-peak energy, TWh	26.1	31.1	-16
CO_2 emissions, million tons	24.3	28.0	-13
Revenue, $ billion	3.5	4.1	-16

Renewables force WECC to rethink grid operations

The Western Electricity Coordinating Council (WECC) coordinates and promotes bulk electric system reliability in the Western Interconnection, which extends from southern Canada into northern Mexico and from the Pacific Ocean to the Colorado/Kansas border. The vastness and diverse geography of the region served create unique challenges in coordinating the operation of the interconnected system and in maintaining reliable service across nearly 1.8 million mi^2 (Sidebar 1).

Steve Beuning, director of market operations for Xcel Energy and chair of the WECC Seams Issues Subcommittee, spoke to the need for a paradigm shift in the way the Western Interconnection operates to satisfactorily address the challenges posed by injecting large amounts of renewable energy into the grid.

He began his presentation, "A Stakeholder's View of the Proposed WECC Balancing Market," with a review of Xcel Energy's capabilities (Sidebar 2) and acknowledgement of customer demands for clean energy. Two states Xcel operates in—Minnesota and Colorado—have RPSs requiring that 30% of the kilowatt-hours come from renewables in 2020. Beuning reviewed the variability and uncertainty associated with wind and solar, citing less predictable and less controllable flows on the grid from large-scale penetration.

Another potential sticking point for grid operators is optimizing the line-up of conventional resources for backing-up intermittent renewables. There's no standard methodology used by balancing authorities to determine the type and quantity of conventional resources required to maintain system reliability, he said. One result of this could be that overly conservative system operators might commit resources in excess of those required to balance generation and load, increasing costs and emissions.

Next, Beuning provided needed perspective on the challenge of renewables integration. By 2019, he estimated, state RPS targets in the Western Interconnection would require a minimum of 50 GW of renewable resource nameplate capacity. If those targets increase, as they have in California and Colorado recently, to an average of 27% across the WECC, wind capacity could hit 69 GW and solar 13 GW.

Those numbers themselves don't mean much, so Beuning provided an example of the impact they could have on the grid. He cited the May 2010 "Western Wind and Solar Integration Study" prepared by GE Energy for DOE's National Renewable Energy Laboratory as the source. He said, "At renewable production levels possible within the next decade, the state of Wyoming could have variable generating capability installed that exceeds demand variability by a factor of 57.

Traditional balancing-area methods that seek to internalize such high variability would be quite stressed, Beuning continued, adding that it wouldn't be economically feasible to build enough gas turbines to handle the assignment.

However, data from the study demonstrate that fast intra-hour dispatch across the WECC could be used to mitigate the balancing-area challenge. Beuning pointed to a geographic diversity benefit for this approach. You spread variability over a larger area, he said. There are clouds here, sunshine there and no wind here but wind there, simulating weather patterns from the podium with his hands.

Likewise, there's a coordinated balancing effect to working region-wide rather than within a smaller utility-controlled balancing area. It can mitigate the variability that a given plant might have to handle, thereby reducing the number of on/off cycles, steepness of ramps, etc. The market signal created allows others to respond when opportunity and price are right.

Another benefit is that the amount of local generation required to offset balancing-area variability can be reduced, thereby holding down the cost of electric service.

In general, Beuning said, in the WECC outside California, the balancing-area mindset is traditional "utility." Specifically, operations focus on fixed hourly energy interchange (exports or imports) and all net variability is contained internally. He said that this traditional style of operation already poses significant challenges to some utilities in the Western Interconnection.

One of the behaviors of many western utilities is their fierce independence and disdain for federal "interference" in their operations. Beuning suggested that the traditional mindset in the region might have to change to accommodate large-scale renewables integration and pointed to the California Independent System Operator Inc and others as having demonstrated viable solutions.

He next summarized some of the work WECC was doing to assure a reliable, well-functioning grid in the future—such as developing what it

Stephen J Beuning, *Director of Market Operations, Xcel Energy Inc*

Transmission service and interconnection portfolio rights management are among Beuning's responsibilities, which also include wholesale market stakeholder representation on behalf of the four Xcel Energy operating companies in both the Eastern and Western Interconnections.

1. WECC history

In addition to coordinating and promoting bulk electric system reliability in the Western Interconnection, the Western Electricity Coordinating Council assures open and non-discriminatory transmission access among members, provides a forum for resolving transmission-access disputes, and maintains an environment for coordinating the operational and planning activities of its members.

WECC geographically is the largest and most diverse of the eight regional entities that have so-called Delegation Agreements with the North American Electric Reliability Corp (NERC) to develop and enforce reliability standards within defined geographic boundaries. It is the successor to the Western Systems Coordinating Council, which was founded in 1967 by 40 electric power systems operating in British Columbia and the 14 western states identified on the map.

WECC was formed in April 2002 by the merger of the WSCC, Southwest Regional Transmission Assn, and the Western Regional Transmission Assn.

calls an Efficient Dispatch Toolkit. First tool, the Enhanced Curtailment Calculator, already is being used on a limited basis. Its job is to allocate curtailment responsibility during congestion. Second tool is the Energy Imbalance Market (EIM), to provide fast regional dispatch of generation.

The EIM would rely on security-constrained economic dispatch of voluntary generator offers on a regional basis. Positive operational impacts expected include increased reliability and lower operation costs. Perhaps, most importantly, the EIM retains existing utility balancing areas, but achieves a "virtual consolidation" for operating purposes.

Key point: Although the EIM proposal includes a regional balancing-market function, it does not establish a regional transmission organization or a consolidated regional transmission tariff. This feature is important to several WECC utility stakeholders. The EIM as presently configured would be different than any other market footprint in the nation. Beuning said gas-turbine operators should like it because cost recovery is through a regional market rather than indirect allocations through tariffs.

A benefit/cost analysis of EIM is funded in the WECC's budget for next year with the goal of completing the study by next summer. Open items include the need to develop a tariff for use by participating systems. Plus, a market monitor for detecting and mitigating abusive market or scheduling practices. Assuming WECC stakeholders approve the proposal, it still must pass muster with NERC and FERC.

2. Xcel Energy facts

Regulated operations in eight states: Colorado, Michigan, Minnesota, New Mexico, North and South Dakota, Texas and Wisconsin

Four utility subsidiaries: Northern States Power Co-Minnesota, NSP-Wisconsin, Public Service Co of Colorado, Southwestern Public Service Co

Operates in the both the Western and Eastern Interconnection; specifically in the Midwest ISO, Western Electric Coordinating Council, Southwest Power Pool

Generating capacity (owned): 16,446 MW

Energy mix based on electricity sales: coal, 50%; natural gas, 24%; nuclear, 12%; wind, 8%; hydro, 5%; biomass, 1%; solar, less than 1%

Nation's leading wind-power provider with more than 3000 MW owned or under contract

Customer base: 3.4 million electric; 1.9 million gas

Learn from Texas

Adrian Pieniazek opened his presentation with a personal evaluation of the Texas experience in integrating renewables. The NRG executive said the Electric Reliability Council of Texas (Ercot) likely is a few steps ahead of the nation's other regional transmission organizations (RTOs) regarding renewables integration (Sidebars 3, 4). And while many milestones in its integration plan have been achieved successfully, he continued, there are lingering issues, and much work remains to meet established goals.

Ercot, which operates the electric grid and manages the deregulated market

Billions needed to move Midwest wind to market

Electric Transmission America (ETA), a joint venture between units of American Electric Power Co, Columbus, Ohio, and MidAmerican Energy Holdings Co, Des Moines, Iowa, released in mid October its Phase 2 report on the transmission capability needed in the Upper Midwest to support renewable energy development and transport that energy to population and load centers.

The cost: $25 billion in round numbers.

The Strategic Midwest Area Renewable Transmission Study (SMARTransmission), was sponsored by ETA along with American Transmission Co LLC, Waukesha, Wis; Exelon Corp, Chicago; NorthWestern Energy, Sioux Falls, SD; and Xcel Energy, Minneapolis. ETA was established to build and own HV transmission assets (345 kV and higher voltages) in North America, but not including Ercot.

Quanta Technology LLC, Raleigh, NC, conducted the study. It evaluated extra-high-voltage (EHV) transmission alternatives to support the integration of 57 GW of nameplate wind capacity in the 11-state study region (North and South Dakota, Ohio, Michigan, Illinois, Indiana, Nebraska, Missouri, Wisconsin, Iowa, Minnesota). The 57-GW number reflects a federal RPS requirement of 20% with adjustments for states that have approved RPS requirements or goals in excess of 20%.

SMARTransmission's goal was to develop a 20-yr transmission plan that ensures reliable electricity transport, provides an efficient system to integrate new generation and foster efficient markets, minimize environmental impacts, and support state and national energy policies.

The transmission alternatives chosen for economic analysis during Phase 2 were determined during Phase 1 of the study (access details, including maps, at www.smartstudy.biz). The three systems evaluated during Phase 2 involved building:

1. Nearly 8000 miles of EHV lines, primarily 765-kV.
2. More than 7600 miles of 765-kV and HVDC lines.
3. More than 8600 miles of line, including 4400+ miles of 345-kV service and 3900+ miles of 765-kV service.

The alternative systems transcend traditional utility and RTO boundaries so the study was designed to incorporate a high level of stakeholder input. More than a 100 participants from public and private utilities, state utility commissions, FERC, RTOs, wind developers, and others were involved.

The SMARTtransmission analysis is not all-encompassing. The study did not address cost allocation or routing and siting requirements, and the results are not intended to be used as the basis for RTO approval of specific projects.

for three-quarters of the state, has more installed wind generation—nominally 10,000 MW—than any other region in the country. Wind capacity is expected to almost double soon after the transmission build-out in West Texas is complete in three or four years from now—according to the current schedule.

One thing for certain, there's much to be learned from Ercot's wind-integration efforts. The need for advance planning and new thinking in grid design and operation are particularly important to success. Pieniazek said, "You can't plan the grid the same way you did in the pre-renewables era; it's completely different."

Two points important to the discussion that follows:

- The Ercot grid is not synchronized with either the Western or Eastern Interconnections, by choice, leaving it electrically isolated from the rest of the US except for a couple of dc interties with a total capacity of about 1100 MW.
- Ercot apparently has done an excellent job of integrating stakeholders into its decision-making process to gain consensus before important decisions are made. Pieniazek, for example, NRG's director of market policy for Texas, is a member of the Ercot Technical Advisory Committee, the market-participant group responsible for making recommendations to the board regarding the RTO's policies and procedures.

Getting started. Texas is much like other wind-rich regions: The resource is not where the load is. In Ercot's case, most renewables potential is in the western and panhandle portions of the state while load is in places like the Dallas-Ft Worth metroplex, Houston, San Antonio, and Austin—all of which are in the central and eastern parts of Texas.

Pieniazek described getting started in renewables to meet the goals of the state's RPS as a "chicken and egg" problem. Transmission providers were reluctant to design and build the infrastructure necessary to transport wind energy from remote areas to the loads if the wind generators weren't going to show up; and the wind developers did not want to develop more wind plants until there was some certainty that transmission would be built.

To reconcile the issue, the Texas Public Utility Commission established so-called Competitive Renewable Energy Zones (better known by the acronym CREZ). The CREZ process identified wind developers that had demonstrated financial commitment—that is, posted collateral, leased land, etc.

3. NRG's Texas operations

NRG Energy Inc operates nuclear, wind, and coal- and gas-fired plants in Texas with a total capacity of 11,500 MW. Renewables (wind) account for 440 MW, NRG's share of the South Texas Nuclear Project is 1175 MW, coal-fired units produce 4150 MW, and gas-fired assets generate 5735 MW.

In terms of operating duty, 5325 MW are base load, 4991 MW are in intermediate service, and peakers total 744 MW. The company's four West Texas wind farms are not included in these totals.

4. Ercot by the numbers

Customers served: 22 million (85% of Texas demand)
Area served: 75% of Texas land
Installed capacity: 84,237 MW; wind accounts for 9865 MW (2010)
Available capacity: 75,755 MW (less than 10% of the wind capacity, and less than half the capacity of the region's two dc interties, are considered "available" on-peak)
High-voltage transmission: 40,327 miles
Record peak demand: 65,715 MW

Once there was sufficient financial commitment from wind developers, the PUC then would have an indication of the amount of transmission they would ultimately approve.

While the PUC was working on CREZ, Ercot developed transmission development scenarios for 12,000 to 25,000 MW of wind-energy transfer capability and commissioned GE Energy to study ancillary-service impacts to test the RTO's ability to absorb such massive amounts of wind energy.

In summer 2008, the PUC selected Ercot's 18,000-MW transmission option at an estimated cost of $5 billion. The planned build-out is being done in phases and in priority order. Targeted completion for all CREZ projects is yearend 2013. Based on results to date, Pieniazek thinks the project might cost more and take slightly longer than planned.

Wind is a high-profile energy resource in Texas. Ercot is investigating the viability of about 41,000 MW in its queue. There has been far less interest in solar in the region to date.

The speaker then confirmed what previous presenters had said about the unpredictable nature of wind and offered an overview of Texas' renewables experience. Here are a couple of bullet points:

- Wind as a percentage of total energy resources in Ercot on a monthly basis varied in the first half of 2010 from a low of 6.8% in February to 12.1% in April. The highest percentage to date was recorded last June 12 when wind generation hit 7016 MW for one hour—15.8% of the load being served at that time.
- During Ercot's peak-hour load of 64,805 MW on August 16, however, wind output was only 650 MW.

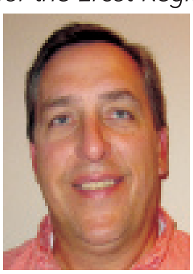
The big challenge to successful integration of variable renewable resources, Pieniazek said, was achieving the goals in a manner that (1) maintains system reliability, (2) ensures costs are assigned in a fair and non-discriminatory manner, and (3) does not undermine existing market structures. He made a special point about the importance of attempting to assign costs to those who create them—as much as possible. The proper alignment of incentives and/or costs increases market efficiencies.

There's nothing like a major system disturbance to help focus attention on the challenges, Pieniazek continued. In February 2008, a dramatic variation in wind energy output and a significant deviation from submitted wind energy schedules did just that.

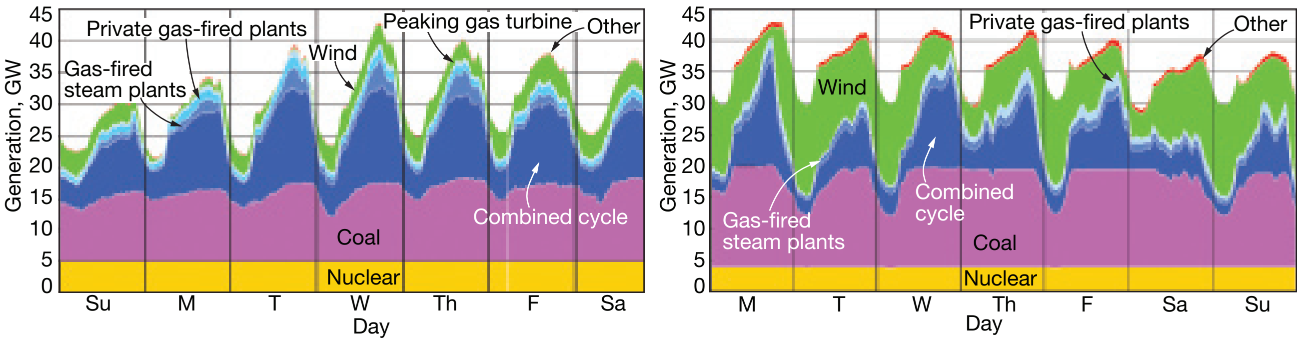
The risks to grid reliability associated with poor integration procedures are magnified in a region such as Ercot's because there's no interconnection with another major balance area for backup. Black-start resources must be well-maintained in Texas.

Pieniazek put up several slides to illustrate dispatch schedules for an actual spring week in 2009 and a projected spring week in 2013, based on a system model that assumes CREZ work will be completed and 18,000 MW of total wind generation will be commercial (Fig 12). While the timing probably is optimistic, the result is about the same

Adrian Pieniazek, *Director of Market Policy for the Ercot Region, NRG Texas LLC*



Pieniazek manages regulatory matters for NRG Texas with an emphasis on wholesale market design and policy. He is a member of the Ercot Technical Advisory Committee, the market-participant group responsible for making recommendations to the board regarding Ercot policies and procedures.



12. Actual dispatch map for Ercot generation assets during a typical week in April 2009 (left) and how that would compare to a windy week in March 2013 (based on modeling results) when almost double today's wind generation is expected in operation

whether it's spring 2015 or later.

Looking at the chart, the NRG executive noted the deep back-down of coal-fired assets and said "this is a huge operational challenge," adding that work is ongoing to ensure the grid will be able to accommodate such a scenario when it occurs.

The real world. Pieniazek updated the group on how Ercot has responded to the challenges of renewables integration encountered thus far, noting pitfalls to avoid and best practices to embrace. The RTO's responses are grouped as follows:

- **Dispatch/operational.** (1) Congestion between West Texas and load centers has been chronic and Ercot operators often must reduce wind as necessary to maintain transmission equipment with rated limits. CREZ is expected to help here.

  (2) The generation (MW) and prices offered by wind resources to curtail often are in negative territory because of zero fuel cost and production tax credits offsetting the payment to generate.

  (3) Wind generators are limited in how fast they can respond when released from dispatch instructions to avoid frequency spikes.
- **Forecasting.** Ercot implemented a central, real-time forecasting system that uses site-specific meteorological data (wind speed and direction, temperature, barometric pressure) and wind-turbine availability information in its predictive model. All wind farms are required to use the forecast Ercot develops in their daily resource-plan submittals.
- **Ancillary services.** Ercot has modified its ancillary-service methodology by incorporating wind-forecast uncertainty into operational reserve requirements for non-spinning reserves (30-min availability) and frequency and regulation reserves (online and immediately available).
- **System modeling.** Ercot is working on improving the accuracy of its planning and real-time contingency analysis models. Pieniazek pointed out that the tools used to model a wind farm are not as well developed as they are for large thermal plants.
- **System planning and interconnection standards.** (1) Ercot has placed a renewed emphasis on managing its generator interconnection queue. Reason: Interconnection requirements have changed; those used in the pre-renewables era did not consider the operational challenges of wind generators.

  (2) Wind farms now must provide voltage support and meet voltage ride-through requirements like other types of generation.

  (3) Wind plants also must now provide primary frequency response.

Note that (2) and (3) are in line with Ercot's goal of treating all market participants in a fair and non-discriminatory manner.

On-going work to facilitate renewables integration. As Pieniazek said at the beginning of his presentation, much progress has been made, but there's still much more to do. Here's a punch list of on-going work:

- Determine the impact of wind generation on system inertia to help dampen frequency oscillations; develop potential solutions.
- Develop ancillary-services cost allocations applicable to wind and other intermittent resources and determine if new ancillary services are needed.
- Evaluate the benefits and potential applications for energy storage.
- Investigate the potential benefits of a smart grid in facilitating integration of renewables and conventional resources.
- Study the electrical interactions between transmission lines and wind generators.
- Most importantly, perhaps, ensure that market design provides the proper incentives to install flexible backup generation. The idea here, Pieniazek said, was that if you're going to impose a cost on the system that cost must be allocated back to you. Not an easy thing to do, he added.

Technology solutions

CAES ready to go main stream

Ask most experienced electric-generation professionals about the value proposition offered by compressed-air energy storage (CAES) and you'll likely get a yawn. They probably will recall the lone US plant (there only are two in the world), installed nearly 20 years ago in McIntosh, Ala., to prove the concept's viability, and then add something like "it works, so what?"

Such a response may have been warranted because CAES had no compelling economic justification until the recent addition to the generation mix of a critical mass of intermittent renewables. Bob Kraft, who has spent his career designing and improving gas turbines and their component parts, told the group that in a world demanding ever smaller carbon footprints CAES can play a significant role by maximizing the value of wind and solar resources at an affordable cost.

Pumped-storage hydro (PSH) can achieve the same result, he acknowledged, but its penetration is limited by environmentally driven siting constraints and significantly higher cost of development. Kraft also noted that the price of a CAES system does not increase with size as quickly as it does for a PSH facility. The example he offered: To double the megawatt-hour storage capacity of a PSH plant you have to double the size of the reservoirs, a major budget item; you also must double the size of the CAES reservoir, but it is only about 15% of project cost.

One of the most important points Kraft made during his presentation was that the faster the electric system can respond to the ups and downs in load given the inherently variable generation characteristic of wind and solar resources, the less capacity you need to back up and smoothly integrate renewables. That piqued the interest of many in attendance who had listened over the last year or so to gas-turbine OEMs touting the need for essentially 1 MW of fast-response GT capacity (or spinning reserve) for every megawatt of wind installed.

Kraft figures CAES can back up intermittent renewables with less than half the capacity (megawatt rating) that would be required if peaking GTs were selected to provide the same service. Plus, much of the CAES capacity could come from underutilized conventional gas turbines converted to energy-storage assets. Energy Storage & Power LLC, the company Kraft manages, owned in part by PSEG Global LLC, is working on several major CAES projects—one involving the retrofit of a GE 7B engine for energy-storage service.

Note that CAES responds very quickly to a change in system demand because the expander turbine operating on compressed air from storage can ramp at rates that could top 25 MW/*sec*. Ramp rates for gas turbines generally are about 30 MW/*min* today. For a warm start, the expander turbine can reach full capacity in about three minutes.

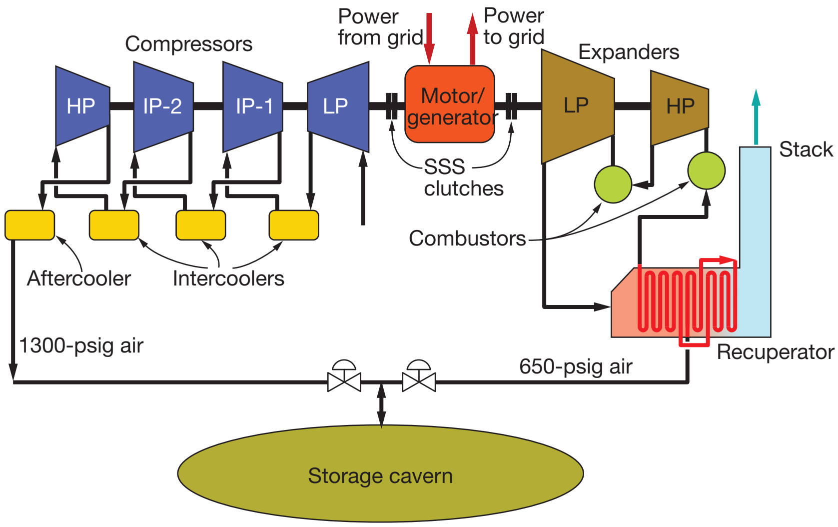
First-generation CAES. To illustrate the recent advancements in CAES technology, Kraft showed a diagram of the McIntosh system (Fig 13). The purpose of this facility was to optimize base-load coal and nuclear generating plants and increasing peaking capacity. Important points to remember:

- McIntosh has a single compressor train that puts 1300-psig air in a storage cavern solution-mined from a salt formation 1500 ft under ground. The size of the 22-million ft^3 cavern is roughly equivalent to the volume of a 20-story building occupying a typical city block. The cavern is relatively small compared to similar facilities used for storing natural gas.
- In charging operation, the motor/generator is disconnected from the expander turbines by opening the right-hand SSS clutch shown in the diagram and engaging the other clutch. The m/g operates as a motor, consuming 0.81 kWh of grid power for every kilowatt-hour of power generated when air is released to the expanders.
- When fully charged, this cavern can support 26 hours of continuous power-train operation at rated output. Heat rate is 4100 Btu/kWh.

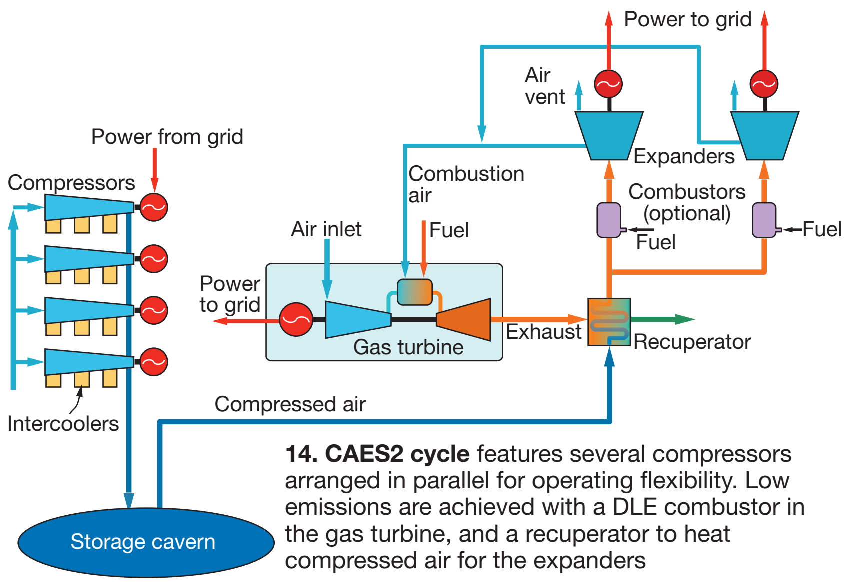
ES&P's CAES2. Kraft introduced his company's CAES2 system with Fig 14, showing how a new or existing simple-cycle gas turbine could be transitioned to energy-storage service. Using gas turbines of different sizes, the cycle shown is scalable and adaptable to a range of conditions, with a unit producing from 5 to 450 MW. For applications requiring from 5 to 20 MW of CAES, compressed-air storage is practical in an above-ground vessel; from 20 to 450 MW, storage would be in an underground cavern. Kraft stressed that the CAES2 uses only proven technology and equipment.

Bob Kraft, PE, *President & CEO, Energy Storage & Power LLC*

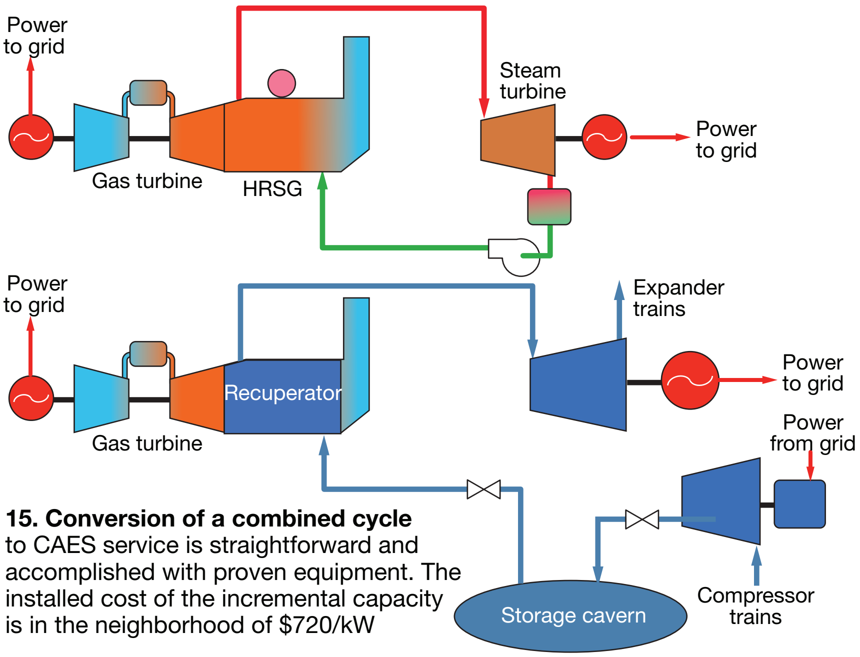
Kraft was one of the founders of PSM, the world's largest aftermarket supplier of hot-gas-path components for GE7FA and W501F gas turbines. The 25-yr industry veteran spent more than a decade designing military engines at GE and P&W before switching to the industrial side. At PSM, now owned by Alstom, his leadership and vision were key to developing the company into a 250-person global organization with service, repair, and commercial operations capable of competing head-to-head against the OEMs' aftermarket businesses.



13. First-generation CAES is characterized by a single train of air-cavern charging compressors and external combustors for the expanders



14. CAES2 cycle features several compressors arranged in parallel for operating flexibility. Low emissions are achieved with a DLE combustor in the gas turbine, and a recuperator to heat compressed air for the expanders



15. Conversion of a combined cycle to CAES service is straightforward and accomplished with proven equipment. The installed cost of the incremental capacity is in the neighborhood of $720/kW

Key points of this design include the following:

- Multiple compressors, each equipped with its own intercoolers, arranged in parallel for charging the storage vessel or cavern. This improves flexibility for renewables integration and enables simultaneous charging and discharging of the cavern.
- A degree of power augmentation is achieved by extracting some compressed air after it does work in the first couple of expander stages and injecting this bleed air into the combustion wrapper. Also, keep in mind that the expander exhaust generally is below ambient temperature, usually about 50F. Alternatively, this cold exhaust air can be routed to the GT inlet to maintain nameplate performance levels on hot days.
- Emissions from CAES2 are minimal because the only fuel that must be burned is that in the gas turbine, which is equipped with a DLE (dry, low emissions) combustion system. GT exhaust heat is transferred to air discharged from the cavern in a recuperator before it enters the expander, eliminating the need for the external combustor shown in Fig BK1.

The CAES2 described in the drawing for a Frame 7B-E engine produces 172 MW at a heat rate of 3771 Btu/kWh. It requires only 0.71 kWh to produce a kilowatt-hour of power for the grid. Performance is better than for first-generation CAES primarily because of the recuperator.

Next, Kraft discussed the value proposition for converting to CAES a 2 × 1 F-class combined cycle seeing limited service (Fig 15). Here the 2 × 1 combined cycle is repurposed as a 1 × 1 unit with the CAES expanders coupled to the second 7FA gas turbine. Output of the 1 × 1 portion of the project analyzed would develop 238 MW without duct burners in operation, 268 MW with supplementary firing of the heat-recovery steam generator (HRSG).

Total output of the CAES portion of the plant is 388 MW—a production increase of 150 MW compared to the conventional plant with no duct firing. Kraft estimated the capital cost of the additional power at about $720/kW—including the new expander and compressor trains, conversion of the HRSG to a recuperator, construction of an underground storage cavern, and balance-of-plant requirements.

Kraft closed out the CAES portion of his presentation by comparing the cost of bulk energy storage alternatives today. Were a new 7FA-powered CAES2 plant developed from the ground up rather than converting an existing unit for energy-storage service, it would cost upwards of $950/kW—or about a third more than converting an existing plant. A new PSH facility would cost from about $2500 to $4000/kW.

Lithium-ion batteries were mentioned as an alternative to PSH and CAES2, but considered uneconomic in sizes above about 20 MW and for discharge times of more than one hour at the current stage of development. Cost estimate is $1500/kW.

Power augmentation. Kraft addressed power augmentation in the last part of his presentation—specifically ES&P's patented humid air injection (HAI) system for combined-cycle plants (access www.ccj-online.com/archives.html, click Spring 2004, click "Water injection a concern?" on cover). The system promises cold-day performance on a hot day for a nominal $300/kW depending on the specific powerplant arrangement, ambient environment, etc.

Simply put, HAI involves the injection of a steam/air mixture into the GT compressor discharge just ahead of the combustor. A standard motor-driven compressor is installed to supply the compressed air for this purpose. The extraction point for steam preferred by thermal engineers is the cold reheat line because it is thought to provide the best combination of power augmentation and heat rate.

The first commercial project is planned for a 2 × 1 7FA-powered combined cycle at PSEG Fossil LLC's Bergen Generating Station. It is expected to deliver a 50-MW net increase from the Bergen unit on a 95F day. Output of each GT increases by about 35 MW, but the steam turbine output drops by about 15 MW because less steam flows through it, and the air compressors increase the parasitic power draw.

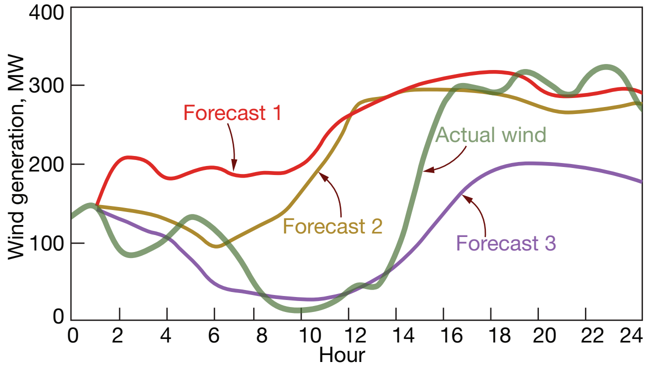
GT enhancements can facilitate renewables integration

The dozen presentations preceding Bruce Rising's made it clear that responsibility for dealing with the idiosyncrasies of intermittent renewables rested squarely on the shoulders of the balancing authority—ISO, RTO, or regulated utility. Also, that generating plants powered by gas turbines typically are best suited for filling the gaps in renewables production caused by clouds and changes in wind speed.

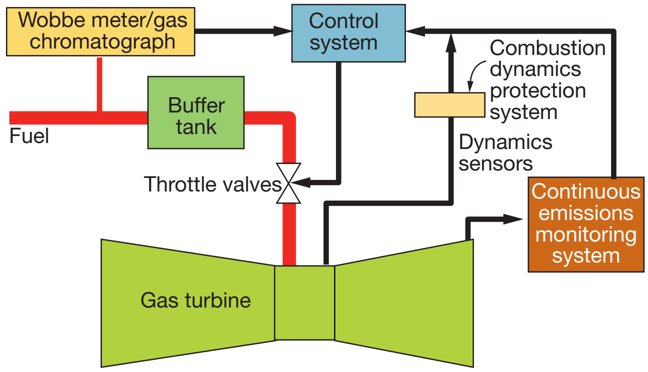
Rising's assignment was to update the group on the capabilities of the latest large frame gas turbines; plus, identify enhancements available to owner/operators for upgrading existing engines to more effectively support grid operations. The ability to provide both ancillary services—such as reactive power and voltage control, load following, etc—and energy is conducive to a stronger balance sheet.

Rising opened his presentation with a passing salute to the "traditional" power market, in which the dispatch order of conventional assets is based on the cost of generation. He then noted the uncertainty surrounding how units will be dispatched in the future in areas with a high penetration of intermittent generation.

The renewables footprint already is becoming evident in system response, Rising said. Ramps up and down are faster and starts appear more frequent. A Siemens' assessment indicates



16. One wind-forecast assessment project produced the results described. The solid green line is actual wind generation, the other three were produced by competing forecasting software tools.



17. Fuel flexibility is provided by system shown above to mitigate the impact of changing gas properties—including heat content

that a significant amount of installed thermal capacity is approaching a 50-operating-year threshold and that 50,000 to 70,000 MW of old coal-fired capacity could be retired in the near term because they are of marginal value for supporting renewables, as well as other reasons.

Intermittent renewables pose forecasting challenges, Rising continued. Important to remember is that *installed* renewables capacity does not equate to *available* capacity. Tools for forecasting wind are subject to increasing error the further out in time the forecasts are made; also, significant variability exists among forecasting methods (Fig 16). Such uncertainty may force backup generating units into rapid ramp events that adversely impact equipment lifetime.

Faster ramps and more starts/stops are not the only challenges facing conventional assets once wind and solar penetration reach a critical threshold. Thinking is that increased turndown of base-load units may be required, with the need to operate units as low as 30% of rated capacity to avoid shutdowns and increasing the number of start/stop cycles.

Fast ramping also may have adverse impact on the efficiency of environmental controls, and could raise permit issues. Trying to balance fuel supply against unpredictable consumption may pose contractual challenges as well.

All gas-turbine OEMs offer or are developing technologies to mitigate the adverse effects of deep cycling and fast ramping. In addition to extended turndown capability, Rising said Siemens can provide the following:

- Fast-start units—Flex-Plant™ 10 and Flex-Plant 30.
- Power augmentation via wet compression and/or higher duct firing to help "fill in the generation gaps" when the wind slows or stops.
- Power Diagnostics® for rigorous monitoring of assets and related instrumentation to advise when maintenance shutdowns are needed to prevent equipment damage.

Note that Flex-Plant 10 refers to a simple-cycle F-class engine capable of injecting 150 MW of firm capacity into the grid within 10 minutes of being called.

Flex-Plant 30 is the product name for an F-class 2 × 1 combined cycle designed to deliver a nominal 500 MW within 72 minutes (hot start condition; 16 hours or less from last shutdown) when conventional drum-type heat-recovery steam generators are installed; five minutes faster with Benson (once-through) HRSGs. The GTs can deliver their rated capacity in 22 minutes with the Benson option; in 32 minutes with a conventional HRSG.

By contrast, a conventional 2 × 1 would require 116 minutes to achieve full output and GT power would not be available for 108 minutes.

For a warm start (up to 64 hours since the last shutdown), a conventional 2 × 1 would require 152 minutes to deliver GT power, 162 minutes to get the entire plant online. Compare these numbers to 37 and 81 minutes for the F-P 30 with drum HRSGs and 22 and 75 minutes with once-through boilers. Note that actual startup times may vary slightly because of ambient and other local conditions.

Rising spent several minutes describing Siemens' solution for expanded turndown with low CO emissions, and its fuel-flexibility option incorporating a combustion dynamics protection system with feed-forward tool to minimize power fluctuations and fast-response Wobbe meter with redundant gas chromatograph (Fig 17).

Subscribers who actively participate in the 501G, F, and D5-D5A user groups and in the CTOTF's Siemens Roundtable probably are familiar with these offerings. If not, you can get a real-world view of their implementation at www.ccj-online.com/archives.html, click 3Q/2009, click "Klamath gets better with age" on the issue cover. Or you can access Rising's presentation at www.integrating-renewables.org.

Before wrapping up, Rising allowed attendees to peek into the Siemens development pipeline at a solution currently in field validation to assure that users operating at low GT loads will not exceed CO and NO_x emissions limits. Virtually all HRSGs built in the last several years are equipped with SCR (selective catalytic reduction) catalyst to restrict NO_x emissions to the ultra-low levels required by law.

Some have CO catalyst as well, but many do not. For those in the latter group requiring expanded turndown capability, addition of CO catalyst is necessary to insure that CO emissions remain below permit limits during transients. The traditional way of doing this would be to add an oxidation catalyst bed ahead of the SCR. But oftentimes the necessary space is not available.

The Siemens answer is to replace the existing SCR catalyst with the company's Novel catalyst, which destroys NO_x and CO simultaneously. It is

Bruce Rising, *Strategic Business Manager, Siemens Energy Inc*

Rising started his career in engineering and science and moved to the business side. A former scientist in energy and environmental R&D, he served Siemens as manager of regulatory affairs, and as manager of marketing intelligence in the company's global strategy group, before accepting his current position.

designed to operate over a wide range of GT loads and, because it occupies less volume than traditional SCR catalyst, system pressure drop is lower.

Pilot test results included the following: less than 1 ppm ammonia slip; less than 2 ppm combined reduction capability for NO_x, CO, and volatile organic compounds; lower emissions of CO and VOCs; minimal formation of ammonia sulfates and bisulfates in the cool end of the HRSG.

Thomas P Mastronarde, PE, *Project Engineering Manager, Gemma Power Systems LLC*

Mastronarde provides technical analysis and support for energy-project development and is responsible for the timely and accurate completion of engineering during project execution. Emerging opportunities for hybrid solar thermal/combined cycle plants is one interest area. He spent 35 years at Alstom and its predecessor companies, rising to chief engineer for HRSGs.

Injecting solar steam into the HRSG

Tom Mastronarde, well known to the CTOTF community for his HRSG design acumen, discussed the integration of a solar thermal steam system with a conventional heat-recovery steam generator. In particular, plant and asset managers wanted to know if it were possible to retrofit a solar thermal array to an existing combined-cycle plant and what the value proposition was for doing so.

The boiler designer began by assuming that the retrofit candidate was a conventional supplementary-fired, 2 × 1, F-class combined cycle, located in the Southwest, having a nominal capacity of 500 MW with no duct burners in service. Peak capacity with supplementary firing ranged from 560 to 630 MW. Another key assumption: 235 acres were available onsite to accommodate a solar field capable of producing an incremental 50 MW of power.

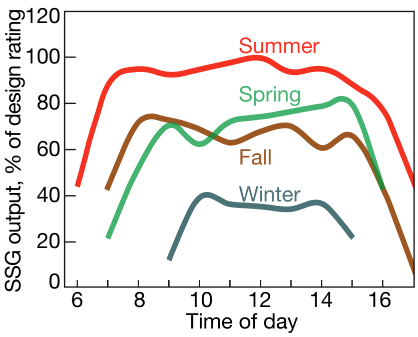
Proven solar trough technology was selected for Mastronarde's study and a DNI (direct normal irradiation, a measure of solar intensity) of 1000 W/m^2 was assumed. Nominal flow from the solar steam generator (SSG) to achieve the desired 50 MW is 450,000 lb/hr. Steam pressure floats during operation from about 1100 to 1700 psig; temperature is a relatively constant 700F.

Superheated steam from the SSG would be introduced into the HRSGs' saturated steam lines upstream of the inlet to the first HP superheater section. Feedwater would be supplied to the SSG evaporator section from the combined-cycle's HP feedpump discharge.

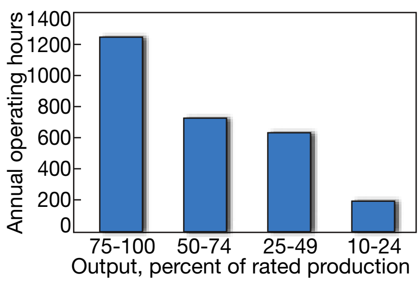
Mastronarde compared output and heat rate on a 94F day with evap coolers on and both gas turbines operating at full load (total of 335 MW) for the following system line-ups:

- Unfired combined cycle, no solar component: Plant output, 516 gross/503 net MW; heat rate (net, based on LHV), 6256 Btu/kWh. Note that steam turbine (ST) output is found by subtracting plant gross output from the 335 MW produced by the GTs—181 MW for this operating scheme.
- Unfired combined cycle with SSG producing half its rated output (225,000 lb/hr), indicative of fall and winter operation: Plant output, 541 gross/526 net MW; heat rate, 5983 Btu/kWh.
- Unfired combined cycle with SSG producing rated output (450,000 lb/hr), as it would on a clear summer day: Plant output, 566 gross/549 net MW; heat rate, 5732 Btu/kWh.
- Combined cycle with full supplementary firing and no solar component: Plant output, 615 gross/598 net MW; heat rate, 6606 Btu/kWh.

Integrating a solar-trough system into an existing combined cycle is relatively straightforward, according to Mastronarde. Plant thermal and electrical equipment and infrastructure already are in place to produce power and deliver it to the grid. Plus supplemental firing can be used to compensate for variations in solar thermal output to maintain desired plant output. Incremental staff requirements would be minimal to keep mirrors clean and maintain the thermal fluid system (often referred to as heat-transfer fluid, HTF) that transports heat from the solar field to the SSG.



18. Seasonal variation in the production of solar thermal energy is significant



19. Annual capacity factor of the solar steam system is 32% for a typical year with 2810 operating hours

He identified the following impacts on equipment capacity, performance, and operation:

- Steam turbine. HP and reheat steam temperatures are reduced when solar steam is injected at the HRSG superheater inlet. However, there is only a minimal change in moisture content at the ST exhaust.
- Station service transformer must provide about 2200 kW of medium-voltage (MV) power to support the solar operation. If the existing transformer cannot accommodate the additional load, a new 2.5-MVA 4160/480-V transformer is necessary.
- MV switchgear and motor control centers (MCCs) are required to support the solar operation (4.16-kV HTF pumps and 480-V loads).
- Plant DCS (distributed control system) requires additional I/O points and operator graphics to enable integration of the solar and combined-cycle systems.
- Additional demineralized water is needed for mirror washing.

The segment of Mastronarde's presentation having to do with the behavior of solar thermal plants was perhaps of greatest interest to the audience because very few, if any, in the room had any experience with them. He began by saying that SSG output is variable and is affected by the season, time of day, weather conditions, and intermittent cloudiness on sunny days. Certainly no surprise there.

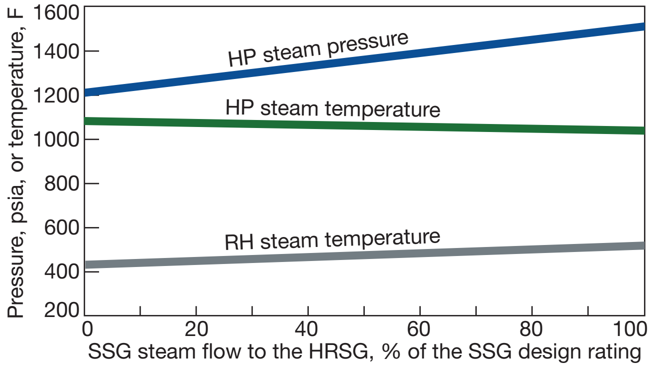
Mastronarde added that plant electric output from solar steam is variable and affected by the number of hours per day that the solar field can absorb the sun's energy, as well as by the proportion of sunny days to cloudy days. Also no surprise.

The "meat" of what the boiler design expert had to say was presented in a series of slides—including Figs 18-20. He also showed in other slides how steam flow and temperature varied on a given day with intermittent clouds (up and down) and how smooth flow and temperature curves were on a clear day (view at the web address noted above).

Most instructive perhaps where the results of a model run to show how solar thermal and electric variables were affected by intermittent clouds that took from 15 to 20 minutes to cover the entire array of collectors. Here are some numbers to keep in mind:

- 95% reduction in incident solar radiation in 12 minutes.
- 50% reduction in SSG steam output in 20 minutes.
- 10% reduction in ST throttle flow in 20 minutes.
- 4% reduction in plant net power output in 20 minutes.

Not worrisome, Mastronarde told the group. The decrease in HRSG steam flow as clouds move over the solar field can be offset by firing duct burners. The rate-of-change of thermal input required from the supplementary firing system (approximately 50% to 60% of burner rated output) within 20 minutes is well within the capability of the duct burner and the HRSG.



20. Steam conditions at the steam turbine's HP and IP inlets show little variation, except for HP steam pressure, over the full range of SSG outputs

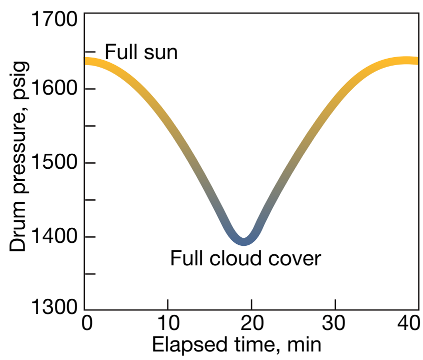
Last segment of the presentation was an analysis of potential fatigue effects from intermittent cloud cover. Mastronarde ran through a quick exercise to show why he believes an HRSG could be subject to 60,000 thermal cycles from intermittent cloud cover over a 25-year life. He then showed a curve to illustrate the pressure swing that occurs during one "solar cycle," which with full sun, proceeds to full cloud cover, and then returns to full sun within 40 minutes (Fig 21). Pressure varies over the cycle by 240 psi, or 11% of the HP drum's 2200-psig design pressure.

The design engineer said that according to Section VIII of the ASME *Boiler & Pressure Vessel Code,* "Cycles in which the pressure variation does not exceed 20% of the design pressure are not limited in number." The screening criterion for temperature cycles: "Cycles in which the metal temperature differentials between any two adjacent points in the pressure vessel are less than 50 deg F are not limited in number.

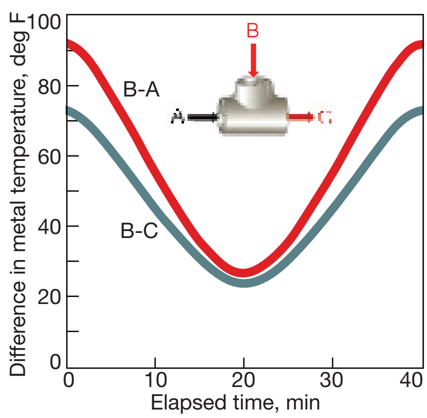
The HP drum satisfies both these criteria and its service life is unaffected by pressure or temperature cycles caused by intermittent cloud cover. Thus a fatigue analysis was not required.

Evaluation of the tees that combine superheated steam from the SSG and saturated steam from the HRSG drum before the mixture enters the HP superheater produced a different result for a 60,000-cycle lifetime. During the cloud-induced transient, the 6-in.-diam (Sch 120) SA 106B pipe delivering superheated steam from the SSG at 1600 psia/700F (branch B in Fig 22) experiences a temperature drop of 80 deg F at full cloud cover and then rebounds to 700F within the next 20 minutes.

Branch A, with 1637 psia/608F saturated steam from the HP drum experiences a cyclic temperature variation of 15 deg F during the 20 minutes it takes to go from full sun to full cloud cover. The 1627-psia steam in branch



21. Variation in HP drum pressure during a severe intermittent cloud-cover event does not adversely impact drum life



22. Temperature variation in mixing-tee metal temperature during solar transient suggests a fatigue analysis

C (HP superheater inlet) goes from 627F to 596F in the first 20 minutes of the cycle.

Thus, the mixing tee fails the temperature screening criterion, requiring a detailed fatigue analysis. Disappointing as that might sound, Mastronarde said it was likely that a detailed analysis would demonstrate the expected number of thermal cycles are acceptable. If not, the magnitude of the thermal cycles could be reduced by addition of a thermal sleeve to the mixing tee.

For a backgrounder on "Integrating solar, conventional energy resources," visit www.ccj-online.com, access COMBINED CYCLE Journal archives, 2Q/2010 issue, click article title on magazine cover.

Materials considerations for equipment seeing increased cyclic duty

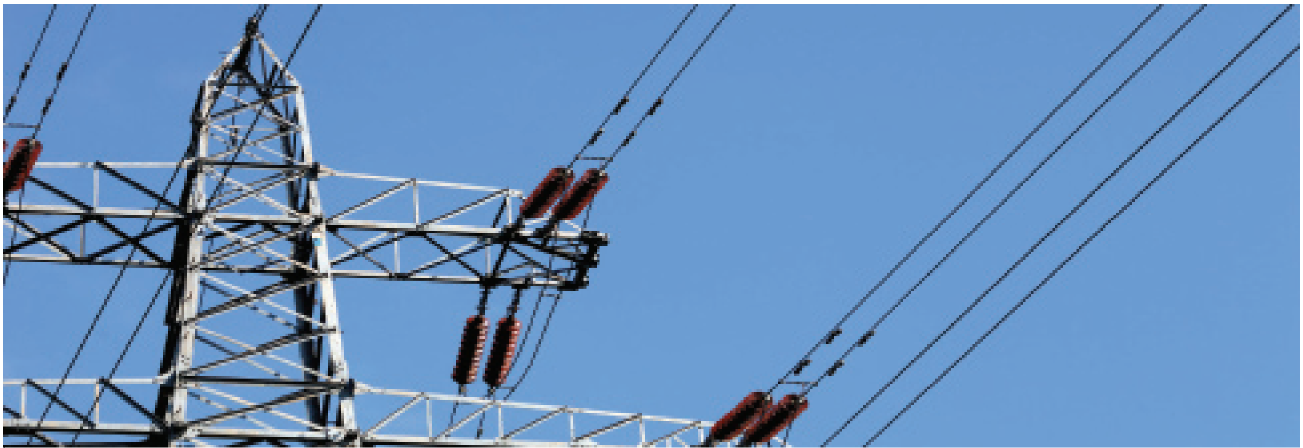
Steve Gressler followed Mastronarde at the podium and focused on the subject that the boiler designer had introduced a few minutes earlier: materials-life considerations for cycling plants. Gressler, a metallurgist, opened his presentation with these three thoughts regarding equipment lifetime management to assure personnel safety and optimal reliability:

- Materials and equipment have finite lives that vary with application and local conditions.
- More rigorous service duty—cycling, for example—accelerates damage rates.
- Fabrication defects and design shortcomings that were benign and tolerable under steady-state conditions increase uncertainty and risk under more demanding cyclic duty.

What owner/operators basically want to know, Gressler said, are the answers to these two questions: (1) Where are the highest risk locations on critical equipment? (2) When will failure occur?

He recommended an iterative process based on well-established phased methodology to get the answers. First identify weak links and their contributing factors. Then selectively progress through more quantitative analyses. Finally, integrate multiple disciplines—such as materials, NDE (nondestructive examination), analysis, monitoring, instrumentation, data management, and economics.

Critical to success, Gressler continued, are an early start (gather knowledge of current condition to serve as a baseline for comparison), consistency,



and an increase in prediction accuracy when the expected time of failure nears. To accomplish the last goal, you must know what constitutes "failure" (crack, distortion, risk level, etc), what the active failure mechanisms are, and what the rate of damage is.

The materials expert told the group that damage can be caused by an independent mechanism, by several in unison, or by several having compounding effects, and then reviewed the failure mechanisms of greatest interest to personnel at generating plants:

- **Fatigue** is a progressive damage mechanism that develops over time because of repetitive and fluctuating thermal and/or mechanical loading. Extent of damage depends on the number of cycles, local stress, and temperature.
- **Creep** is a progressive damage mechanism that develops over time because of the sustained application of stress at high temperature (over 800F). Extent of damage depends on time, temperature, stress, and material. To illustrate: A 16% increase in stress (from 6 to 7 ksi) halves the expected lifetime; a 4% increase in metal temperature from 1000F to 1040F reduces material life by a factor of four.
- **Creep-fatigue** is of concern because the interaction of the two damage mechanisms can reduce material life to 20% of that predicted independently.
- **Corrosion-fatigue,** sometimes called corrosion-assisted fatigue, is characterized by crack initiation from fatigue and the acceleration of crack growth by corrosion and oxidation.
- **Flow-accelerated corrosion,** known simply as FAC, is the thinning of metal by dissolution of the protective oxide layer under certain chemical and flow conditions. It is found most often in boilers (cold-end heat transfer bundles), air-cooled condensers, and condensate systems.
- **Over-stress conditions** result from unintended movement or loading—for example, from water hammer, bending, etc.

To reduce the uncertainty in your predictions of remaining materials life, it's important to know the current condition of your equipment. Accurate documentation is critical to this effort—specifically material specifications and fabrication and installation records.

Sounds simple, but many combined-cycle plants—particularly those built during the bubble years 1999-2004—are missing much of their important paperwork.

If that has occurred at your facility, it's important to conduct the appropriate inspections and compile the needed information. You may find that the requisite materials identification tests reveal the materials specified in construction documents are not the ones installed and achieving the expected equipment lifetime may not be possible—even with flawless operation.

Example: Gressler and his colleagues at Structural Integrity Associates Inc found inappropriate weld material and heat treatment procedures while investigating the condition of high-energy

Steven P Gressler, *PE, Senior Associate, Structural Integrity Associates Inc*

Gressler has more than two decades of experience performing life assessment, failure analysis, and materials evaluation of fossil-power generation equipment—with an emphasis on high-energy piping, boilers, and headers. He spent the first 10 years of his career at Ohio Edison Co in the company's engineering offices and plants. Gressler has contributed to the development of custom inspection techniques, risk-based assessment tools, and evolving methods assessing creep-strength-enhanced ferritic steels.

piping systems at the New Harquahala Generating Co LLC, Tonopah, Ariz. Extensive work was required to correct deficiencies in the main and hot-reheat steam systems. The case history presented in the 2Q/2010 issue of the COMBINED CYCLE Journal, "P91 commands respect," should be required reading for all plant supervisory personnel.

Once true baseline conditions have been established, it's important to continuously monitor plant operations for such anomalies as temperature and pressure excursions, fast ramp, fast startup, turbine trips, etc. Only with this information is it possible to calculate remaining life accurately.

Recall from your gas-turbine experience how OEMs determine when engine inspections are necessary and when critical parts must be repaired/replaced. The same methodology must be applied to other equipment—piping, valves, high-temperature/high-pressure pumps, heat-recovery steam generators (HRSGs), etc.

To better understand the impacts of poor operating practices on equipment life, review the experience of Southern Company Generation with a new software tool designed to track the life remaining in critical HRSG parts. Access www.ccj-online.com/archives, click 3Q/2009, click "New software . . . ." on the cover.

Smart grid

Smart grid: An idea for the future

Scott Matlock presented "Smart power," describing Alstom's vision of how to reduce the electric-power industry's carbon footprint and maximize energy-use efficiency through better information management and the application of emerging technologies—such as carbon capture and storage. However, after listening to several transmission experts discuss the challenges associated with integrating renewables into the generation mix, it became obvious that "smart grid" was not in contention as a viable solution—at least not today.

Alstom's premise is that the global electricity sector faces a significant three-fold challenge: satisfy soaring demand, curb emissions, and develop carbon-free energy resources. The company believes smart grid will help meet this challenge. In its view, "smart grids are set to revolutionize the way we produce, distribute, and consume electricity, delivering major benefits in terms of cost, quality of life, and environmental footprint."

Scott Matlock, *Western Regional Manager, Alstom Power, Automation and Controls*

Matlock has broad experience in electrical engineering. Before joining Alstom, he was VP operations for a Colorado-based engineering organization, regional manager for an electrical distribution company, and engineering manager for a technical customer support team.

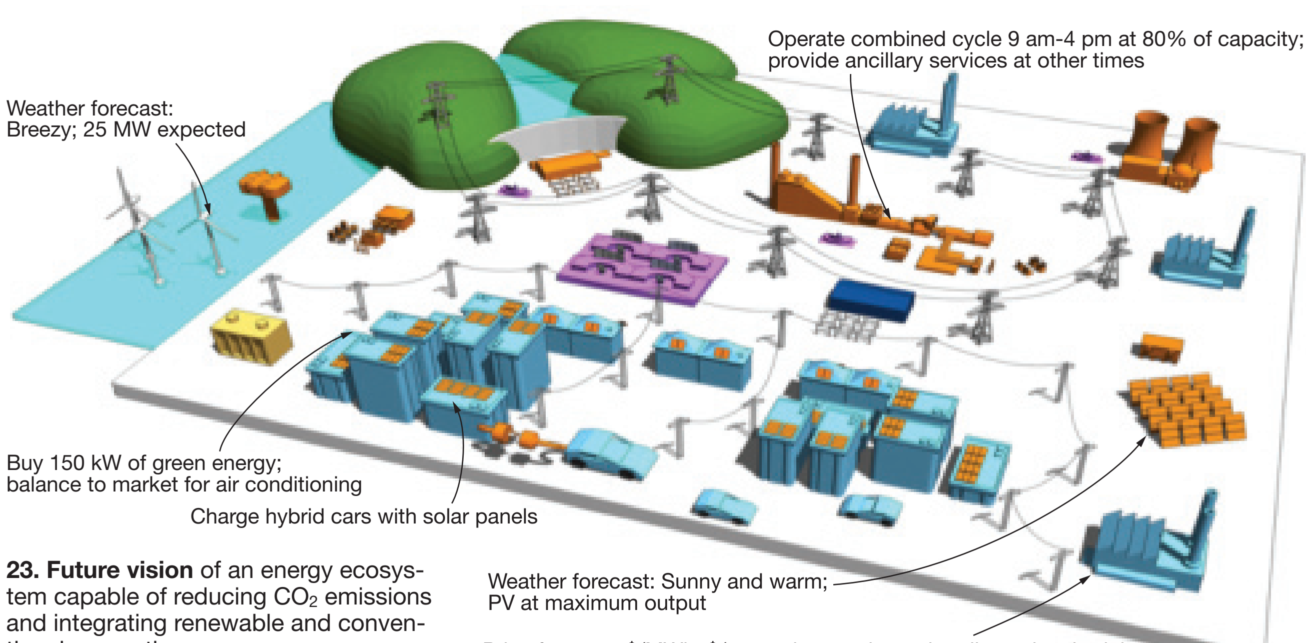
Here, smart grid is defined as an energy transmission and distribution network with embedded control, information technologies, and telecommunications capabilities that can provide real-time information to all stakeholders in the electricity value chain—from the generating plant to the home.

Alstom says that to maximize its return, a smart grid must expand its "smartness" from the end user upwards towards generation resources, allowing independent generators and load-serving utilities to optimize their assets to exactly match demand.

In a few years, the company believes, smart metering and demand management technologies in homes and commercial buildings will extend real-time control of energy use down to consumers. Expectation is that the smart grid would reduce the overall cost of generation and enhance grid stability, thereby facilitating the integration of intermittent renewables.

Smart meters and energy gateways would enable dynamic time-of-day pricing by giving consumers the ability to link up their smart critical appliances—such as hot-water heaters, hybrid cars, solar panels, etc—to local storage units and start operating or recharging automatically when signaled by the smart grid (Fig 23). Consumers also would be able to adjust their appliance settings remotely based on pricing information received on their computers, smart phones, etc, thereby contributing to a reduction in peak-time energy consumption.

Alstom's visionaries say future electricity networks will embed



23. Future vision of an energy ecosystem capable of reducing CO_2 emissions and integrating renewable and conventional generation resources new software applications to better assess risks related to generation intermittency and to allow grids to self-heal in emergency conditions and resist cyber and physical attacks. Such capability would enable operation of grid assets closer to their physical limits thereby reducing the need for capital investments in redundant systems and equipment.

Software applications at the distribution level promise to improve grid connection availability, avoiding costs incurred by businesses and consumers for power fluctuations and outages. The ability to share real-time data across the distribution system would further increase the transparency and liquidity of the energy wholesale market, bringing new storage and demand-response resources to reduce the need for standby generation. The expected result: A safer, more reliable, more efficient electric grid.

Injecting renewable energy into the distribution system

Jonathan Hawkins focused on PNM Resources' work to integrate renewables generation with the distribution system (Sidebar 5). One motivator for this effort is New Mexico's RPS, which requires that 1.5% of the company's green electricity be produced by distributed generation facilities in 2011, rising to 3% by 2015.

PNM Resources currently gets most of its renewable energy from the 200-MW New Mexico Wind Energy Center, which has been operating since early 2003. The 136-turbine facility remains among the largest wind plants in the country.

New Mexico is said to have more than 300 "sunny" days a year, making PNM Resources the perfect partner for DOE in a Smart Grid Demonstration Project that would incorporate a utility-scale battery (2 to 4 MWh) with a 500-kW solar (photovoltaic) installation.

Energy storage makes good sense, Hawkins said, because peak electric production from PV does not align with peak usage (Fig 24). Note that summertime peak demand occurs about two hours after the peak solar time. In winter, the separation between peak electric production and demand is greater. A battery allows electricity produced at the peak solar times to be used when customer demand peaks.

5. PNM Resources facts

Regulated utility
Service territory: Parts of New Mexico and Texas
Customers: 859,000
Generation: 2717 MW (40% coal, 37% natural gas, 15% nuclear, 8% renewables)

A 200-MW wind farm represents more than 90% of the company's renewables portfolio. New Mexico's RPS requires that 20% of the kilowatt-hours (retail) the company produces in 2020 come from renewable resources. Other milestones: 10% in 2011, 15% in 2012

Jonathan Hawkins, *Manager of Advanced Technology and Strategy, PNM Resources*

Hawkins is responsible for new-technology R&D—including smart-grid technologies and strategy, integration of distributed energy resources, and energy storage. He is the company's advisor to EPRI programs on integration of distributed renewables, IntelliGrid, and smart-grid demonstrations, and is a voting member on the National Institute of Standards and Technology's Smart Grid Interoperability Panel.

Based on work done thus far, Hawkins continued, simple arbitrage alone would not produce a large enough benefit stream. However, by monetizing other benefits—such as carbon reduction, deferred fuel, deferred T&D system build-out, enhanced reliability, etc—a battery might be justified financially. A battery also adds value by smoothing fluctuations in distribution voltage normally caused by intermittent sources such as PV.

Much work remains before the PV/battery system can be considered a firm, dispatchable renewable resource and achieve the stated goal of reducing peak demand by a minimum of 15%. Areas of ongoing development work include these:

- Develop and test computer-based modeling tools capable of simulating the behavior of distributed generation and storage interconnected with the distribution system. The use of computer-based models can allow PNM to scale aspects of the project virtually to investigate other scenarios. As an example, the utility can look at the effects of larger PV installations or larger battery storage by scaling actual data.
- Optimize the intelligent control algorithms that will operate battery installations on utility grids.

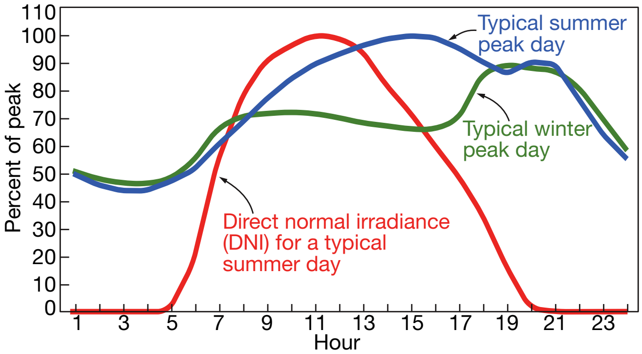
Other project objectives are the following:

- Demonstrate mitigation of voltage fluctuations by the battery system.
- Quantify and refine associated performance requirements, operating practices, and cost/benefit.
- Reduce greenhouse-gas emissions through the expanded and more beneficial use of renewables.
- Extrapolate, where possible, the benefits of storage when coupled with renewables.

The DOE-funded demonstration project involves many organizations in addition to PNM Resources, including the following:

- Sandia National Laboratories: system integration and design support; testing and evaluation.
- University of New Mexico: system modeling and analysis; battery control algorithm development.
- Northern New Mexico College: data analysis.
- EPRI: Analysis and modeling using the research organization's Intelligrid methodology. The PNM/DOE project benefits from the utility's selection by EPRI as one of 11 worldwide hosts under its Smart Grid Demonstration Program. Under this program, PNM and EPRI are currently engineering the design and operation of commercial smart-grid systems.
- Industry vendors, such as manufacturers of batteries and PV systems.

Finally, Hawkins said that knowledge gained by PNM Resources' personnel is being shared with the industry and the nation by participation in these programs.



24. Solar power produced at maximum DNI is stored in a battery and released later in the day when demand is highest

Case studies

Renewables already impacting NV Energy's grid operations

NV Energy, which worked with CTOTF in developing the Integrating Renewables Workshop, brought its "A" team to the meeting to explain the challenges it faces and how it expects to satisfy the requirements of the state's demanding RPS (Sidebar 6).

Senior VP of Energy Supply Jeff Ceccarelli welcomed attendees to Reno and gave a quick review of the utility's history. NV Energy and its predecessor companies have been a catalyst for Nevada's economic development since before the 20th century.

The first electricity the utility produced was in the Reno area, host city for the workshop. It was used for lighting the mining town of Virginia City and for pumping water from the deep shafts of the area's world famous silver mines. Thomas Alva Edison personally designed Virginia City's first electric distribution system.

VP Generation Kevin Geraghty set a positive tone for the workshop and explained the integration challenge the company has in its northern territory. Note that NV Energy operates two independent grids today. Sierra Pacific Power Co built the northern grid and Nevada Power Co the southern grid before the companies merged in 1999. A north-south transmission line linking the two systems, named the One Nevada Transmission Line (or the shortened ON Line), is under construction and expected to be in commercial service at the end of 2012.

Geraghty began with his thoughts on change. "There has never been a time in this industry when there wasn't change," he said. The challenge, the executive continued, is to embrace change and accomplish the specified goals with minimum cost impact while maintaining service quality and making electricity production and delivery cleaner and safer.

Tall order for sure. But Geraghty reminded the group of how the industry had successfully adapted to wrenching change in the past. The Clean Air Act was one example. It dramatically changed coal-fired plant design and operation, first requiring unheard of (at the time) levels of particulate removal, then SO_2 removal, then NO_x destruction, then mercury removal, and so on.

The Clean Water Act again proved the industry's capability to adapt to change. Plants built before the 1970s typically discharged water—except perhaps for oily drains—through a big pipe directly into a natural watercourse. Today many generating facilities discharge no liquids whatsoever beyond the plant boundaries.

Accommodating intermittent renewables, Geraghty said, was simply the generation industry's next challenge.

Customer attitudes have changed over time as well. The VP recalled for the group "the early days," when the customer requirement simply was "hook me up." Next, customers wanted lower rates, more reliable service, faster hook-ups. Today many customers view the utility as a "safety net" for solar PV and other distributed generation tied to home and business operations.

Geraghty called for the industry "to rise and meet a new level of customer requirements." Customers don't want to hear about "intermittency," power-quality issues, or any of the industry's other challenges, he said. The electricity supply business was relatively easy in the "old days" Geraghty continued. Utilities had to grow the market, attract new customers, increase electric consumption. Today, "we're selling efficiency, to help the customer reduce the cost of energy."

Setting the stage for the next

three NV Energy speakers, Geraghty reviewed challenges facing the company on its northern grid regarding integration of "must take" intermittent renewables at a time when demand is decreasing. The whole idea of "must take" can be viewed as a contradiction because a utility sometimes is obligated to take wind energy when no customer needs or wants it.

Richard Salgo, the company's director of electric-system control operations, offered his perspective as a "grid operator." He began with an overview of reserves, regulation, and balancing, some of which had been covered earlier by Clyde Loutan of the CalISO.

The basic function of a balancing authority (BA) is to continuously balance loads and resources within a metered boundary, he said. It must ensure that grid frequency is controlled and that all interchange is properly transacted. Also, that the BA does not become a burden to interconnected neighbors by over- or under-generating.

Salgo next put up the area-control-error equation (too detailed for this presentation; access www.integrating-renewables.org), calling it the "barometer of balancing performance." You want the ACE to be zero, he said; if it's negative (positive) number you must increase (decrease) generation.

Area load demand, satisfied by BA generation and interchange, traditionally has been considered out of the grid operator's control. But that may not be true going forward, Salgo said, because the smart grid may enable load control at the customer—at least in some instances. Integration of intermittent renewable resources certainly will make BA generation far less predictable than it is today and complicate the management of interchange.

Spinning reserves, which provide both a portion of the BA contingency reserve requirement and the regulation room for preserving balance as load fluctuates, will have to meet more demanding requirements to accommodate the variability and/or intermittency of renewables. Ramp rates generally will have to be faster and operating ranges extended compared to spinning reserves serving conventional generation.

Operation of NV Energy's northern grid is already constrained and renewable generation is only a fraction of what it will be in 2025. Example: Nighttime minimum demand can be as low as 700 MW to 750 MW and total production from required thermal assets operating at minimum load and "must-take" renewables already is at that level.

With demand flat, at best, given the economic slowdown, and the need to keep adding more renewables capacity to satisfy the RPS, the challenge is clear. Salgo said the only apparent solution today is to curtail wind production as needed during low-demand periods. Smart grid can't help much, if any, because there's little load that can be curtailed.

What the grid operator expects of the generation fleet is more cycling capability, faster ramps, lower minimum loads, and the ability to make more frequent load adjustments. Demand-side expectations include improved load forecasting (a smart-grid deliverable), demand reductions to compensate for sudden dips in output from solar and wind resources (robust DSM capability), and load-shaping to approximate the expected renewable-portfolio supply curve.

Gary Smith, the company's director of smart technologies just smiled at Salgo's demand-side expectations as he walked to the podium. Smart-grid development is moving forward quickly under Smith's direction as evidenced by the recent rollout of the utility's Advanced Service Delivery (ASD) program. Foundation of this $301-million program, approved by the Nevada PUC last July 30: advanced metering and a 900-MHz communications network supported by 144 towers statewide.

NV Energy is a DOE grant recipient, so the federal government is chipping in $138 million for the purchase and installation of 1.3 million electric meters and 150,000 gas modules statewide. Meter installation is expected to take up to three years.

The ASD system—reliable, scalable, and secure—will enable customers to take ownership of their energy consumption eventually by scheduling energy purchases and taking advantage of off-peak discounts, etc. Smith showed the cutaway of a home a few years from now with solar PV on the roof, electric vehicles, home area network, demand-response capability, advanced metering, automated gas modules, etc. You can see it at www.integrating-renewables.org.

Operational benefits of ASD are estimated at about $35 million annually. Big savings are expected from eliminating about 17 million manual meter reads annually and from

6. NV Energy backgrounder

Customer base: 2.4 million Nevadans, 93% of the state's residents

Service territory: 54,500 mi^2

Demand: 5500 MW in the south, 1800 MW in the north

State RPS: Now at 12% of kilowatt-hour sales; ramps to 25% by 2025 with at least 6% from solar resources. Conservation can be 25% of the RPS

Nevada is ranked No. 1 in installed solar energy capacity per person

Nevada is ranked No. 1 in installed geothermal energy capacity per person

Renewables capacity totals 1241 MW (44 projects) and includes geothermal, solar PV, solar thermal, waste-heat recovery; solar thermal with storage, biomass, and wind either in production or under development.

Dariusz Rekowski, *Generation O&M Director, NV Energy*
Rekowski joined NV Energy in 2006 after 14 years with Destec Energy Inc and Dynegy Generation in various engineering, construction, commissioning-support, and management positions. First assignment at NV Energy was as plant director for the Clark/Sunrise complex.

Richard J Salgo, PE, *Director of Electric System Control Operations, NV Energy*
Salgo is responsible for the interconnected operation of NV Energy's transmission grid and balancing areas in northern Nevada and the Las Vegas area. His experience includes electric system design, system protection, construction and field operations, and grid operations.

Gary Smith, *Director of Smart Technologies, NV Energy*
Smith is responsible for the company's Smart Grid program development—including vision, strategy, investment grant, and regulatory interface. He also manages the implementation of NV Energy's advanced meter infrastructure and meter data management.

Inequality among renewables

Most generation professionals in the electric power industry are relatively unfamiliar with how hydroelectric projects *really* work. The prevailing view that flowing water turns a generator shaft to produce electricity, while true, does not acknowledge the complexities associated with the operation of these facilities.

Consider the Bonneville Power Administration, which markets power from federal dams along the Columbia River system within the constraints and requirements for other river purposes. Flood control, protection of fish listed in the Endangered Species Act, compliance with the Clean Water Act, etc, take precedence over power production.

And now there are "must take" renewables to accommodate. As part of its mission to market federal hydropower, BPA is the primary high-voltage transmission provider in the Columbia River Basin, home to more than 3000 MW of wind-powered generators. Consistent with FERC (Federal Energy Regulatory Commission) policies for open-access, non-discriminatory transmission, BPA integrates new power sources into its grid as requested.

Wind capacity in the area served by BPA is being developed well ahead of regional power demand growth because of the challenging Renewable Portfolio Standards promulgated by the western states. In fact, 80% of the wind power generated along the Columbia River is delivered to utilities located outside BPA's balancing authority area.

The rapid increase in wind power production in the Northwest (along the Columbia River and elsewhere in the region) has increased the power system's maximum output by a significant amount. Meanwhile, the balancing reserves needed to accommodate wind have consumed a major portion of the Federal Columbia River Power System's operating flexibility.

To illustrate: Columbia River gorge wind patterns are extremely variable and storms cause large up and down ramps that are hard to predict with precision. To accommodate the 3000 MW of wind power currently interconnected to the federal system, BPA now sets aside about 850 MW of hydro capability to provide incremental (INC) reserves and about 1050 MW to provide decremental (DEC) reserves.

Translation: BPA runs hydro generation 1050 MW higher than minimum generation at all times so it can reduce hydro production (DEC) if the wind picks up and suddenly increases above its schedule. In addition, hydro generation is run 850 MW below maximum generation at all times so BPA can increase hydro output (INC) if wind dies and wind generation falls below its schedule within an hour.

One impact of rampant growth in renewables generation is illustrated in a recent report, "Columbia River high-water operations," DOE/BP-4203, September 2010. BPA had been aware for some time that a combination of high stream flows and high wind could pose new challenges for its Columbia River system operations.

Such a "perfect storm" occurred during the first two weeks of June 2010, in an otherwise low-water year. BPA considers this event a likely preview of situations the organization and region will face again, and for longer periods during years of heavy snow.

Simply put, this was the conundrum caused by the freak weather system: Maximum wind and hydro generation together exceeded demand; reservoirs behind dams along the Columbia rapidly filled to maximum capacity; a need to control "spill"—that is, dumping water downstream without generating power—to control the amount of nitrogen in the river water. High amounts of nitrogen can be lethal to fish.

To minimize excess spill, federal hydro facilities produced, at times, more than twice as much power as needed to meet BPA demand. Since generation must equal demand, BPA was forced to sell its power at prices down to $0/MWh to reduce excess spill and manage total dissolved-gas levels. During the first two weeks of June, BPA disposed of more than 50,000 MWh for free, or for less than the cost of associated transmission.

But maximizing hydro generation was not enough to manage the high flows and prevent reservoirs from overfilling; spill flows had to be increased. Such additional spill is termed "lack-of-market spill" since it would not have been necessary had there been additional markets for power.

All thermal facilities in BPA's balancing authority area were reduced to the minimum loads necessary to keep them connected to the grid during the weather anomaly. For example, the nuclear plant known today as the Columbia Generating Station was operated at less than 20% of its rated output for a few days to avoid a shutdown.

Grid impacts. Finally, because federal hydro generators were producing far in excess of BPA demand, and wind power and other resources also required transmission, the grid was stressed. Transmission availability significantly limited opportunities for increasing hydro generation to reduce dissolved-gas levels in the river.

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improved energy-theft detection. DSM programs also are expected to reduce generation requirements by 245 MW by the end of 2012, including commercial and industrial. Load control in residences and small commercial operations, peak-time rebates, programmable thermostats, and home-area networks are reducing demand by nearly 150 MW today. Goal is to double that number within a few years.

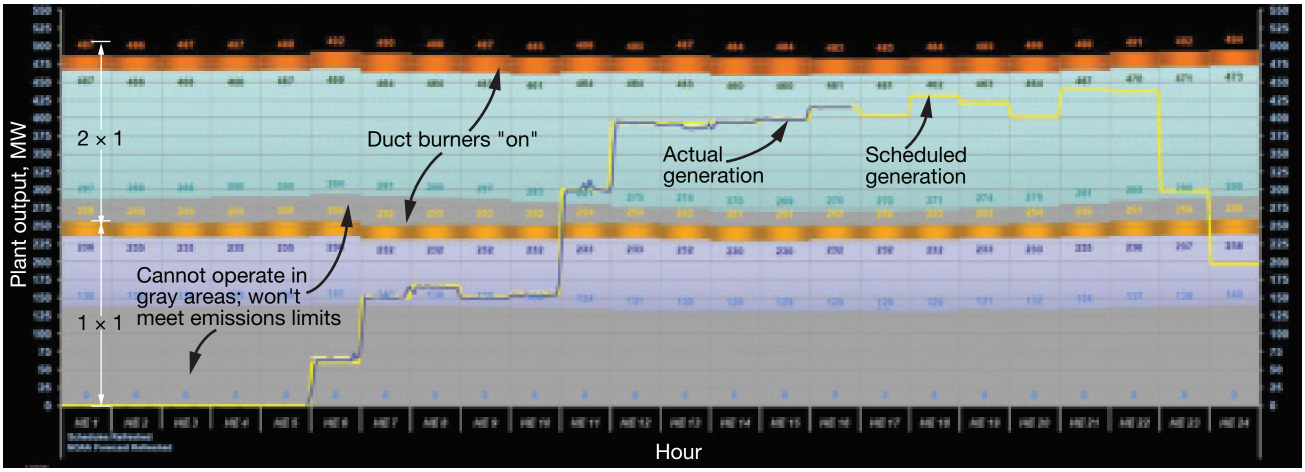
Dariusz Rekowski, director of fleet O&M and the last of NV Energy's presenters, opened by acknowledging the grid operator's expectations of generation and noting that providing dispatch flexibility to support grid stability and demand is conducive to lower operating efficiency, faster ramps, and more stop/start cycles.

They, in turn, contribute to lower capacity factor, increased wear and tear on parts, and a higher number of maintenance cycles. The result: higher O&M costs and outage timing adjustments. Rekowski said it was clear that the company had to spend its O&M dollars more wisely by adopting condition-based, rather than time-based, maintenance and to make better use of its workforce by moving people among plants for planned maintenance.

The former plant director of the company's Clark, Sunrise, and Higgins generating plants said the challenges of running conventional assets to support renewables included the following:

- Higher emissions per megawatt-hour produced.
- Part-load operational issues.
- Transient-mode operation.
- Higher fuel consumption (higher heat rate).

Rekowski cautioned that more frequent cycling of conventional assets might introduce issues not seen in base-load service. Specifically, he was concerned about water chemistry/treatment effects, turbine water induction, safety, high-energy piping issues, etc.



25. Startup and loading of the Klamath combined cycle for a typical economic-dispatch scenario shows five hours of operation with one gas turbine in service before firing the second unit

Flexibility of conventional resources underpins renewables development

Mike Roberts stressed early in his presentation that one of Iberdrola Renewables' goals is industry leadership in optimizing the flexibility of existing resources to enable more renewables development (Sidebar 7). The ability of a generator to balance its renewable and conventional resources within someone else's balancing authority reduces wind-integration charges—a drag on the bottom line.

Roberts is well versed in such matters. He was the plant manager of the company's gas-turbine-based generating facility in Klamath Falls, Ore, from before the 2 × 1 F-class combined cycle at the site was commissioned in July 2001 until it—and the plant's 100 MW of fast-start peaking capcity—was purchased by Iberdrola in 2007.

Shortly thereafter, Roberts turned over the Klamath keys to Ray Martens, an active participant in CTOTF and the 501F User Group, and moved up to Portland to manage the company's power assets and their operation.

Iberdrola Renewables wanted the ultimate in flexibility at Klamath: A base-load unit capable of daily cycling. Roberts and Martens made that happen by implementing a cornucopia of best-in-class performance upgrades from Siemens Energy that had satisfied the OEM's rigorous commercial test criteria but collectively had never been installed on one engine.

In combination, the upgrades demonstrated these operational benefits:

- Increase in generating capability of up to 6% at base load.
- Improvement in base-load heat rate of up to 2%.
- Better part-load heat rate.

Other benefits included the following:

- Turndown to 50% of rated capacity without exceeding 10 ppm CO when ambient temperature is between 59F and 95F. Operation at lower load off-peak saves fuel and reduces wear and tear on parts.
- Opportunity to reduce total emissions during engine startup.
- Increased SCR efficiency at low load.
- Extended intervals between overhauls.

For details on the Klamath upgrade, access www.ccj-online.com/archives.html, click 3Q/2009, click "Klamath gets better with age" on the cover.

Roberts followed Makansi at the podium and supported the previous speaker's contention that gas turbines were likely to have a major role in integrating renewables. He said that rapid wind development presented challenges to balancing authorities and that GT resources were well suited to provide flexible capacity, as the Klamath upgrade attests.

That wind development is both rapid and challenging in the region supported by the Western Electricity Coordinating Council (WECC), where Iberdrola Renewables is approaching 2000 MW of total installed capacity, was reflected by two bullet points in Roberts' presentation:

- Wind capacity in the WECC could more than double to 14,000 MW by the end of 2012.
- The statement by Bonneville Power Administration on September 6 offering wind developers a choice: "BPA can carry more reserves (with fewer curtailments) and charge higher wind-integration rates, or carry fewer reserves (with more curtailments) and level lower rates."

Recall that BPA markets wholesale electric power from federal hydro projects in the Columbia River Basin and a handful of non-federal nuclear and hydro generating facilities. It operates about 75% of the high-voltage trans-

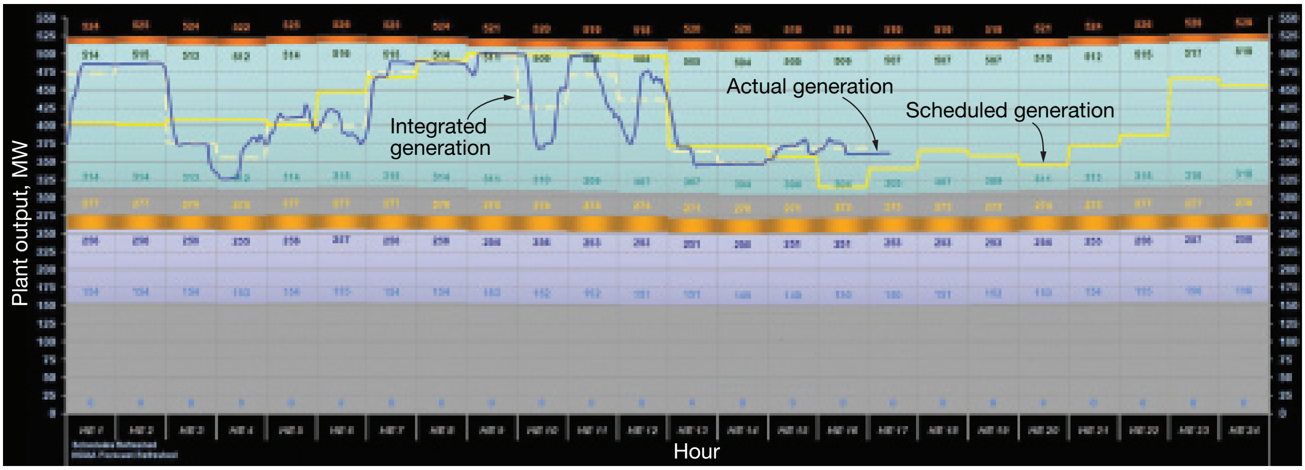
Michael Roberts, *Managing Director of Power Asset Management and Operations, Iberdrola Renewables*

Roberts has held increasingly responsible positions in his 25-year industry career, including plant engineer, O&M manager, and/or plant manager positions at four gas-turbine-based and three biomass generating facilities. He was on the management teams for construction, startup, and commissioning of both the Crockett and Klamath Cogeneration Plants.

7. Iberdrola Renewables backgrounder

Iberdrola Renewables is the world's leading wind generator with 12 GW installed and more than 58 GW in the pipeline. The company ranks second in the US, with wind turbines currently producing 3800 MW. Half of Iberdrola Renewables' planned projects are in the US, where the company earns about one-third of its revenue.

The US operation also has 636 MW of combined-cycle and peaking capacity in southern Oregon. Plus, 155 billion ft^3 of owned and contracted natural gas storage positions Iberdrola to successfully accommodate a volatile future.



26. Integrating wind requires flexible assets to ramp up and down throughout the day

mission capacity in its service territory which includes Idaho, Oregon, Washington, and western Montana, and extends into four other states.

BPA has unique challenges posed by integration of intermittent renewables because the region served is dominated by hydro resources, the operation of which are impacted by regulations to insure protection of fish and wildlife, flood control, navigation, and irrigation as well as load-following and regulation (BPA sidebar).

Dynamic turbine operation, Roberts said, was likely to emerge in the future as the demand for flexible capacity grows; there is no formal market for flexibility today. He foresees the possibility of sub-hourly products that allow owners of flexible generation to bid INC and DEC capacities. Flexible capacity, he continued, would create *additional* revenue opportunities and would not adversely impact the delivery of scheduled energy.

"Optimizing a mixed portfolio of renewable and flexible resources is more difficult than either is alone," Roberts added. However, the payback of intra-company balancing to suit grid needs is that it minimizes wind-integration charges.

Looking ahead, Roberts noted that decision-making tools are critical to integration success, but that the maintenance implications of intermittent renewables on conventional assets would be difficult to define. He suggested that complex computer modeling of the "resource stack" would be needed and that it had to be reliable, fast, and user friendly to real-time traders, plant operators, wind forecasters, and others alike.

Roberts showed the group two slides to illustrate how the Klamath combined cycle was operated in the "old world" of economic dispatch (Fig 25) and in the "new world" requiring the balancing of wind resources within the hour (Fig 26). CCJ

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- Golf tournament, Monday, June 6, 1 pm.
- Presenters' dinner, Monday, June 6, 6 pm.
- Technical presentations and open discussions all day Tuesday June 7 and Wednesday June 8 and the morning of Thursday June 9.
- Vendor fair open during all breaks, breakfasts, lunches all three days.
- Family night dinner and entertainment, Wednesday June 8, 6 pm.

Key contacts:

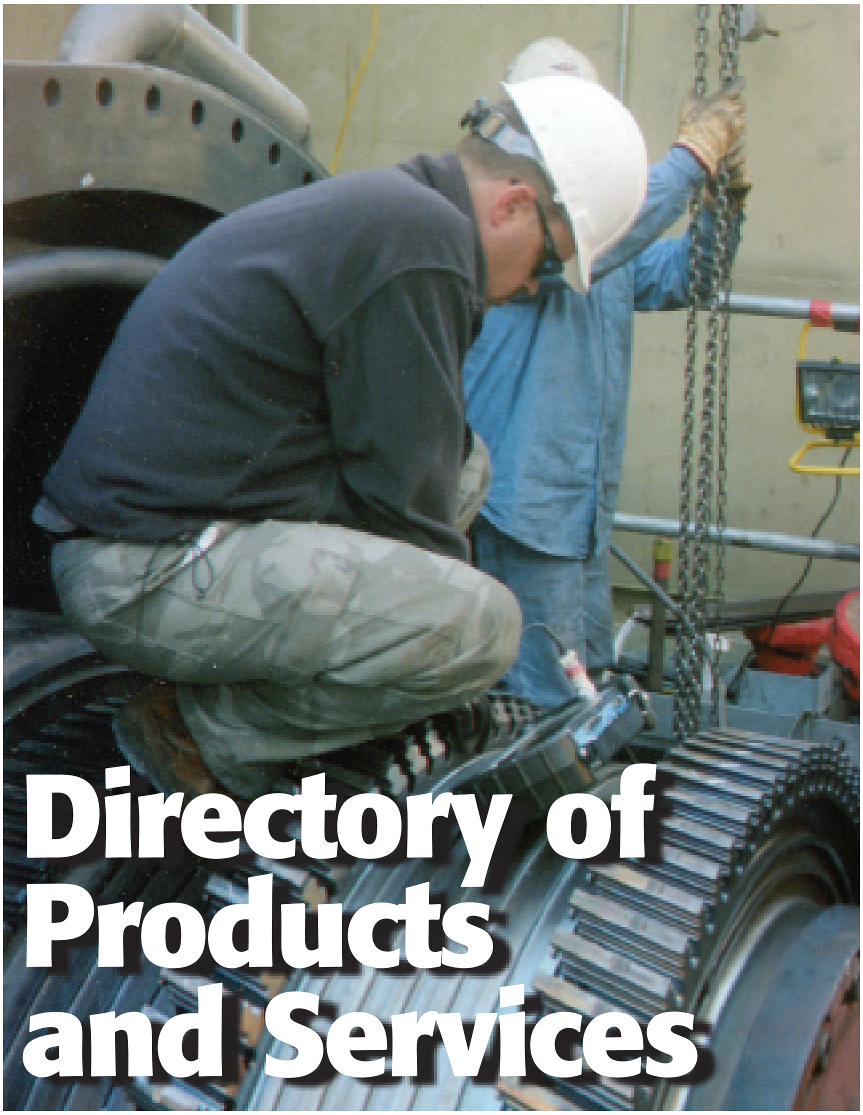
- Golf, Mike Bryan (mbryan@tep.com)
- Presentation idea, Kurt Bayburt (kbayburt@aepco.coop)
- Vendor fair, Kurt Bayburt (kbayburt@aepco.coop)
- Registration and other inquiries, Andrea Mitchell (amitchell@tep.com)

Fee schedule:

- Early bird registration (before March 1), $400
- Regular registration (March 1 and beyond), $450
- Booth fee, $500. Plus, every person participating in the vendor fair must register at the rate in effect on the registration date ($400 or $450)—no exceptions. Plus, plus, package receipt and storage charges (for up to seven calendar days prior to the event) are billed at $0.49 per pound and the shipper's responsibility
- Golf is $50
- Family night dinner, $20 per person; children 12 and under are free

IMPORTANT: www.southwestchemistryworkshop.org launches February 1, 2011

Program updates and details on how to register will be posted to this site, which will include presentations from the 2009 and 2010 meetings. You can access the 2009 presentations now at www.combinedcyclejournal.com/southwestchemistry.html.



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How to use this resource. Suppose you have to repair—possibly replace—gas-turbine blades and vanes during an upcoming hot-section overhaul and need an up-to-date list of repair shops and new-parts suppliers to contact for a quote. Turn to the Products and Services Directory and find in the subsection "Gas Turbine/Generators and Auxiliaries" the category "Blades and vanes" (page 125). If you know a new set of first-stage blades is required for the outage, look down the list of suppliers and find ones with a number "4" in the parentheses to the right of the company names. These are the companies that can help you. Then use the Company Directory to obtain website addresses for further research as well as contact information.

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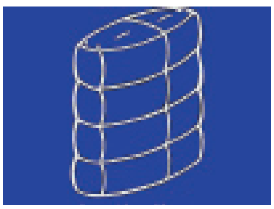

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Contact: Eric R Sohne
E-mail: esohne@yf.com
Phone: 315-552-3203
Fax: 315-457-9204

Y&F is the premier fuel control supplier for combustion turbines for both long-term hydraulic solutions and, more recently, innovative all- electric controls solutions. Our product scope supports natural gas, liquid, syngas, and alternative fuels as well as providing air controls to provide proper fuel to air mixtures. Additionally, Y&F provides auxiliaries that control turbine motoring for cool down to prevent rotor droop, translating nozzle control and improved performance from optimal controls. We have been called by our OEMs, "Simply the best electric controls in the industry today!" At Y&F we look forward to supporting your needs.

Zokman Products Inc.
www.zok.com

1220 Gump Rd.
Fort Wayne, IN 46845
Contact: Rick Parker
Email: zzockman@aol.com
Phone: 260-637-4038
Fax: 260-637-5031

Zokman Products is the master distributor covering the Americas from our main supply hub in Fort Wayne, Indiana since 1999.

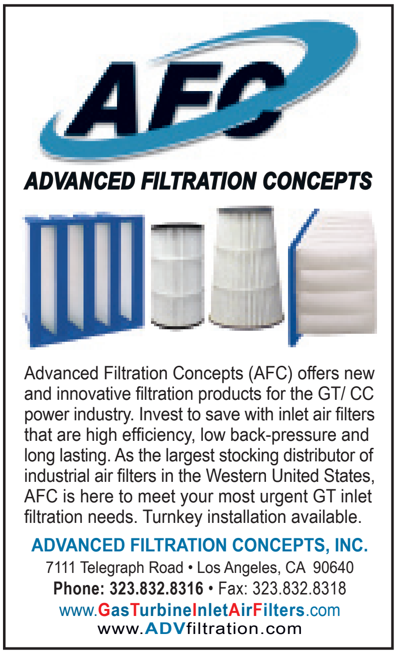
ZOK27 & ZOKmx are concentrated water based, non-flammable fluids for turbine gas path cleaning.

ZOK27 & ZOK mx are approved for use by all the leading engine manufacturers.

PRODUCTS AND SERVICES DIRECTORY

GAS TURBINE/GENERATORS AND AUXILIARIES

Air filters



Advanced Filtration Concepts Inc
Aeroderivative Gas Turbine Support Inc
ALSTOM Power Inc
Braden Manufacturing LLC
Donaldson Company Inc
DRB Industries LLC
ETS Power Group
The Hilliard Corporation
Pneumafil Corp
Power Support Inc
Powmat Ltd
Roblicorp
TDC Filter Inc
Turbine Technics Inc
TVS Filters

Air-inlet houses

Advanced Filtration Concepts Inc
ALSTOM Power Inc
Braden Manufacturing LLC
Donaldson Company Inc
DRB Industries LLC
Moran Iron Works Inc
Pneumafil Corp

Bearings/bearing repair

1 Roller
2 Journal

Aeroderivative Gas Turbine Support Inc (1,2)
ALSTOM Power Inc (2)
D-R Leading Edge Turbine Technologies (2)
ETS Power Group (2)
Mitsubishi Power Systems Americas (1,2)
Powmat Ltd (1,2)
Roblicorp (1)
Sulzer Turbo Services
Turbine Technics Inc (1,2)
TurboCare (2)

Blades and vanes

1 Compressor, repair
2 Compressor, replacement
3 Turbine, repair
4 Turbine, replacement

Advanced Turbine Support Inc (1)
Aeroderivative Gas Turbine Support Inc (1,2,3,4)
Allied Power Group LLC (1,2,3,4)
ALSTOM Power Inc (1,2,3,4)
BASF Corporation
Chromalloy (1,2,3,4)
Creative Power Solutions (1,2,3,4)
D-R Leading Edge Turbine Technologies (1,2,3,4)
DRS Power Technology Inc (1)
ETS Power Group (2,3,4)
Bob Fidler Services Inc (1,2)
Liburdi Turbine Services Inc (1,3,4)
Liburdi Turbine Services LLC (1,3,4)
Mitsubishi Power Systems Americas (1,2,3,4)
Pratt & Whitney Power Systems (3,4)
PSM - An Alstom Company (1,2,3,4)
Roblicorp (2,4)
Siemens Energy (1,2,3,4)
Sulzer Turbo Services (1,2,3,4)
Trinity Turbine Technology LP (1,2,3,4)
Turbine Energy Solutions (2,4)
Turbine Technics Inc (2,4)
TurboCare (1,2,3,4)
Wood Group GTS (1,2,3,4)

Borescopes

Advanced Turbine Support Inc
Aeroderivative Gas Turbine Support Inc
D-R Leading Edge Turbine Technologies
Gas Turbine Efficiency
Olympus NDT
Pond and Lucier LLC
Siemens Energy
Sulzer Turbo Services
Wood Group GTS

Clutches and couplings

ALSTOM Power Inc
The Hilliard Corporation
Power Support Inc
Powmat Ltd

SSS Clutch Company Inc

Sulzer Turbo Services

Turbine Technics Inc

Coatings

1 Compressor blades and vanes
2 Hot-gas-path

Aeroderivative Gas Turbine Support Inc (1,2)

ALSTOM Power Inc (1,2)

BASF Corporation

Chromalloy (1,2)

Creative Power Solutions (1,2)

D-R Leading Edge Turbine Technologies (1,2)

ETS Power Group (1,2)

Jansen's Aircraft System Controls (2)

Liburdi Turbine Services Inc (1,2)

Liburdi Turbine Services LLC (1,2)

Mitsubishi Power Systems Americas (1,2)

Powmat Ltd (1)

Pratt & Whitney Power Systems (2)

Praxair Surface Technologies (1,2)

Gas Turbine Efficiency is a global innovation company. We make power generation greener and more profitable by designing and delivering forward-thinking "clean" solutions that improve efficiency and productivity, reduce costs, and create significant long-term value for our customers and the environment.

Combustion

- Fuel Nozzle and End Cover Repair
- Dynamics Monitoring Systems
- Monitoring and Diagnostics

EcoValue™ Performance and Availability Solutions

- Efficiency and Fuels Management
- Automated Tuning of Gas Turbines
- Conversions
- Gas Handling, Metering, Analysis, Blending
- Compressor Wash
- Power Augmentation
- Modernizations of Auxiliaries

Field Service & Parts Supply

- On-site Outage Management & Maintenance Services
- Technical Field Assistance
- Instrument Calibrations
- BOP & Auxiliary Spares

PSM - An Alstom Company (1,2)

Sulzer Turbo Services (1,2)

Trinity Turbine Technology LP (1,2)

Turbine Technics Inc (4)

ECT has developed cleaners (R-MC and PowerBack), injection equipment and patented power augmentation systems for industrial gas turbines and a variety of other centrifugal and axial flow rotating equipment. ECT mechanical designs include manifold nozzle rings and arrays for on and offline cleaning, power augmentation, fogging and NOx control. We also design and fabricate customized fluid delivery skids for each of these technologies. Each nozzle arrangement and delivery system is engineered for cost effectiveness, ease of maintenance and durability.

In addition, we can provide engineering support services such as Performance Evaluations and CFD Modeling to offer each customer a turnkey option. Along with our European affiliates, we have delivered over 1000 gas turbine cleaning and fluid injection systems.

TurboCare (1,2)

Wood Group GTS (1,2)

Combustors

1 Replacement parts
2 Retrofits/upgrades
3 Combustion dynamics monitoring

Aeroderivative Gas Turbine Support Inc (1,2,3)

Allied Power Group LLC (1)

ALSTOM Power Inc (1,2,3)

Creative Power Solutions (1,2,3)

CSE Engineering Inc (3)

D-R Leading Edge Turbine Technologies (1)

ETS Power Group (1)

Gas Turbine Efficiency (1,2,3)

Innovative Control Systems (2,3)

Liburdi Turbine Services Inc (1,2)

Liburdi Turbine Services LLC (1,2)

Meggitt Sensing Systems/Vibro-Meter (3)

Mitsubishi Power Systems Americas (1,2,3)

Power Support Inc (1)

Pratt & Whitney Power Systems (1)

PSM - An Alstom Company (1,2,3)

Roblicorp (1)

Sulzer Turbo Services (1,2,3)

Trinity Turbine Technology LP (1,2)

Turbine Energy Solutions (1,2)

Turbine Technology Services (2,3)

Wood Group GTS (1,2,3)

Compressors

1 Cleaning, detergents
2 Cleaning, services
3 Cleaning, systems
4 Replacement parts
5 Retrofits/upgrades
6 Air/gas dryers

ALSTOM Power Inc (4,5)

ECT Inc (1,2,3

Bob Fidler Services Inc (2)

D-R Leading Edge Turbine Technologies (1,2,3,4,5)

Gas Turbine Efficiency (3)

Innovative Control Systems

Kobelco EDTI Compressors Inc

Power Support Inc (4)

PSM - An Alstom Company (4)

Roblicorp (4)
Rochem Technical Services USA Ltd (1,3)
Siemens Energy (1,2,3,4,5)
Trinity Turbine Technology LP (4)
Turbine Energy Solutions (4)
Turbine Technics Inc (4)
TurboCare (4,5)
Wood Group GTS (4,5)
Zokman Products Inc (1)

Condition monitoring

ALSTOM Power Inc
Analysts Inc/Sovice Inc
CEC Vibration Products Inc
CSE Engineering Inc
Environment One
Gas Turbine Efficiency
General Physics Corp
Ludeca Inc
Meggitt Sensing Systems/Vibro-Meter
Mettler-Toledo Thornton Inc
Olympus NDT
PSM - An Alstom Company
Scientech
Sulzer Turbo Services
Turbine Technology Services
Wood Group GTS

Control systems and upgrades

Aeroderivative Gas Turbine Support Inc
ALSTOM Power Inc
Analysts Inc/Sovice Inc
CEC Vibration Products Inc
CSE Engineering Inc
DeepSouth Hardware Solutions LLC
D-R Leading Edge Turbine Technologies (4)
Emerson Process Management
Gas Turbine Controls
Gas Turbine Efficiency
Innovative Control Systems
Jansen's Aircraft System Controls
Meggitt Sensing Systems/Vibro-Meter
Mitsubishi Power Systems Americas
Petrotech Inc
Process Controls Solutions LLC
PSM - An Alstom Company
Siemens Energy
Sulzer Turbo Services
Turbine Technics Inc
Turbine Technology Services
Wood Group GTS
Young & Franklin Inc

Emissions control

1 SCR systems
2 SCR catalyst, high-temperature
3 CO catalyst
4 CEMS
5 Low-NO_x efficiency improvement
6 Combustion dynamics production

ATCO Structures and Logistics Ltd (1)
BASF Corporation (2,3)
Braden Manufacturing LLC (1,2,3)
Cormetech Inc (1,2)
Creative Power Solutions
CSE Engineering Inc (4)
EmeraChem (1,2,3)
Express Integrated Technologies LLC (1,2,3)
Gas Turbine Efficiency
Groome Industrial Service Group
The Hilliard Corporation
Innovative Steam Technologies (IST)(1,2,3)
Johnson Matthey Inc (1,2,3)
Nationwide Environmental Solutions (1,2)
Petrotech Inc
PSM - An Alstom Company
Siemens Energy (5,6)
TDC Filter Inc
Turbine Technology Services
Vogt Power International Inc (1,2,3)
Wood Group GTS

Energy storage

Energy Storage & Power

Expansion joints

Braden Manufacturing LLC
Bremco Inc
DRB Industries LLC
KE-Burgmann USA Inc
Multifab Inc
Pneumafil Corp
Powmat Ltd

Fire detection/ suppression systems

Aeroderivative Gas Turbine Support Inc
ALSTOM Power Inc
CSE Engineering Inc
Janus Fire Systems
Petrotech Inc
Power Support Inc
Turbine Technics Inc

Fuels

1 Additives
2 Pretreatment skids
3 Coal gasification systems

4 Filtration

ALSTOM Power Inc (1,2)
ECT Inc (1)
Gas Turbine Efficiency (2)
Powmat Ltd

Gas turbines

1 Under 10 MW
2 10 to 60 MW
3 Over 60 MW
4 Repair and overhaul, field
5 Repair and overhaul, shop
6 Covers
7 Replacement hardware

Advanced Turbine Support Inc (1,2,3)
Aeroderivative Gas Turbine Support Inc (2)
Allied Power Group LLC (5)
ALSTOM Power Inc (3,4,5)
Belyea (1,2,3)
Chromalloy (4,5)
Cogentrix Energy LLC (4)
Creative Power Solutions (1,2,3,5)
CSE Engineering Inc (1,2,3)
Cutsforth Inc (1,2,4)
D-R Leading Edge Turbine Technologies (1,2,3,4,5)
ETS Power Group (2,5)
Fulmer Company (4,5)
Gas Turbine Efficiency (4)
Harco Laboratories Inc
IHI Inc (2,4,5)
Innovative Control Systems
Leslie Controls Inc
Mitsubishi Power Systems Americas (3,4,5)

NAES

NAES Corp (4,5)

PAL TURBINE SERVICES, LLC

Pond and Lucier LLC (4)
Power Support Inc (2,3,5)
Powmat Ltd (2,3)
Pratt & Whitney Power Systems (2,3,4,5)
Process Controls Solutions LLC (2,3)
PSM - An Alstom Company (3,4,5)
Siemens Energy (1,2,3,4,5)
Solar Turbines (1,2,4,5)
Stellar Energy Systems (1)

SULZER

Sulzer Turbo Services (1,2,3,4,5)
Turbine Energy Solutions (1,3)
Trinity Turbine Technology LP (2,3,4,5)
Turbine Technology Services (1,2,3)
TurboCare (4,5)

WG WOOD GROUP

Wood Group GTS (4,5)

Generators

1 Air-cooled
2 Hydrogen-cooled
3 Hydrogen monitoring/control
4 Repairs and rewinds
5 Load testing

FULMER COMPANY DIAMOND

Fulmer Company
www.fulmercompany.com
3004 Venture Court
Export, PA 15632
Contact: Michael Makrevski
Email: mmakrevski@fulmercompany.com
Phone: 724-325-7140
Fax: 724-327-7459

Fulmer Company is an ISO 9001:2008 compliant manufacturer of brush holders, castings, springs and machined parts for power generation, supplying major OEMs globally with engineered designs for new and direct retrofit applications. Our improved FC-101 cartridge-style plug-in brush holder enables brush changes on-line, without service interruption, offering a revolution in turbine-generator reliability.

Advanced Turbine Support Inc (1,2)
AGTServices Inc (1,2,4)

ALSTOM

ALSTOM Power Inc (1,2,3,4)
Belyea (1,2)
Cogentrix Energy LLC (4)
Cutsforth Inc (4)
Fulmer Company (4)
Indeck Power Equipment Co
Innovative Control Systems
NAES Corp (4)

NATIONAL ELECTRIC COIL

National Electric Coil (1,2,4)]
QinetiQ North America (1,2,4)
Siemens Energy (1,2,3,4)
Sulzer Turbo Services (1,2,3,4)
Turbine Energy Solutions (1,2)

TurboCare

TurboCare (4)

Instrumentation

ALSTOM Power Inc
CEC Vibration Products Inc
Creative Power Solutions
CSE Engineering Inc
DeepSouth Hardware Solutions LLC
DRB Industries LLC
Emerson Process Management
Environment One
Gas Turbine Controls
Gas Turbine Efficiency
Innovative Control Systems
Ludeca Inc
Meggitt Sensing Systems/Vibro-Meter
Mettler-Toledo Thornton Inc
Petrotech Inc
Powmat Ltd
Roblicorp
RoMaDyn
Siemens Energy
Turbine Technics Inc
Turbine Technology Services

Lube/hydraulic oils

1 Replacement oil
2 Additives
3 Conditioning
4 Filtration
5 Varnish removal

American Chemical Technologies (1,2,3)
Analysts Inc/Sovice Inc (3)
ECT Inc (2)

Hilliard

The Hilliard Corporation (3)
ExxonMobil Lubricants and Specialties (1,3)

Hy-Pro Filtration (3,4,5)

ISOPur Fluid Technologies Inc (3,4,5)

C C Jensen Inc (3)

Pall Corp (3)

Maintenance tools

ESCO Tool

E H Wachs Co

Noise attenuation

1 Acoustic enclosures
2 Silencers

ALSTOM Power Inc

ATCO Structures and Logistics Ltd (1,2)

Braden Manufacturing LLC (1,2)

DRB Industries LLC (1,2)

D-R Leading Edge Turbine Technologies (1)

Everest Sciences Corp (1)

Innovative Steam Technologies (IST) (1,2)

Moran Iron Works Inc (1,2)

Multifab Inc (1)

Power augmentation systems

1 Wetted media
2 Fogging
3 Mechanical refrigeration
4 Absorption cooling
5 Wet compression
6 Indirect evaporative cooling
7 Humid air injection

Advanced Filtration Concepts Inc (1,2,3,4,5)

ALSTOM Power Inc (1,2,3,4,5)

Braden Manufacturing LLC (1,4)

Caldwell Energy (1,2,3,4,5,6)

Donaldson Company Inc (1,4)

DRB Industries LLC (1,2,3,4,5)

ECT Inc (2,5)

Energy Storage & Power (7)

Everest Sciences Corp (3,6)

Gas Turbine Efficiency (2,5)

Pneumafil Corp (1,2,3)

Stellar Energy Systems (3,4)

Turbine Air Systems (3)

Professional services

1 Consultants
2 Contract maintenance
3 Contract operation
4 EPC
5 CFD analysis
6 Outage planning
7 Performance assessment
8 Shaft alignment
9 Inspection
10 Machinery diagnostic services
11 Contract personnel

Advanced Filtration Concepts Inc (2,7,9)

Advanced Turbine Support Inc (9)

Aeroderivative Gas Turbine Support Inc

Alimak Hek (2,4,6)

ALSTOM Power Inc (2,3,4,6,7,8,9)

Analysts Inc/Sovice Inc (1,7)

Bibb Engineers (1,4,7)

Braden Manufacturing LLC (1,5,7,9)

Chromalloy

Cogentrix Energy LLC (2)

Creative Power Solutions (1,4,5,7)

CSE Engineering Inc (1,2,6,7)

Cutsforth Inc (2,7,9)

Donaldson Company Inc (1,2,5)

DRB Industries LLC (1)

D-R Leading Edge Turbine Technologies (2,3,6,9)

DRS Power Technology Inc (1)

Environment One (1,2,3,6,7)

ETS Power Group (1,6,9)

Bob Fidler Services Inc (1,2,3,6)

Fulmer Company (1,2,7)

Gas Turbine Efficiency (2,5,6,7,9)

General Physics Corp (1,7)

Graycor Industrial Constructors Inc (4)

Innovative Control Systems (7)

Jansen's Aircraft System Controls (1,7)

Liburdi Turbine Services Inc (1,7)

Liburdi Turbine Services LLC (1,7)

Ludeca Inc (8)

Meggitt Sensing Systems/Vibro-Meter (1)

NAES Corp (2)

Olympus NDT (9)

Pond and Lucier LLC (1,6,9)

Power Plant Pro

Power Support Inc (1,9)

Pratt & Whitney Power Systems (4)

Precision Iceblast Corp (2)

Process Controls Solutions LLC (1)

Roblicorp (1)

Sargent & Lundy LLC (1,4,5,6,7)

Scientech (1,6,7)

The Shaw Group (1,4,6,7,9)

Siemens Energy (1,2,3,4,5,6,7,8,9)

Strategic Power Systems (1,6,7)

Sulzer Turbo Services (1,2,3,5,6,7,8,9)

TDC Filter Inc (2)

Turbine Technology Services (1,2,4,5,6,7)

URS Washington Division (1,2,4,6,7,9)

E H Wachs Co (6)

Wood Group GTS (1,2,3,4,6,7,8,9)

Valves

1 Liquid fuel
2 Gas fuel
3 Purge
4 Actuators

Jansen's Aircraft System Controls (1,3,4)

E H Wachs Co

Young & Franklin Inc

HEAT-RECOVERY STEAM GENERATORS AND AUXILIARIES

Access doors

ALSTOM Power Inc
Bremco Inc
Chanute Manufacturing
CMI Energy
Deltak LLC
Duct Balloon
HRST Inc
Moran Iron Works Inc
NEM USA Corp
Vogt Power International Inc

Attemperators

ALSTOM Power Inc
CMI Energy
Deltak LLC
NEM USA Corp

Borescopes

Olympus NDT
Siemens Energy
Control systems and upgrades
ALSTOM Power Inc
CEC Vibration Products Inc
DeepSouth Hardware Solutions LLC
Deltak LLC
Emerson Process Management
Gas Turbine Controls
Indeck Power Equipment Co
Innovative Control Systems
Meggitt Sensing Systems/Vibro-Meter
NEM USA Corp
Petrotech Inc
Process Controls Solutions LLC
Siemens Energy

Dampers

ALSTOM Power Inc
Bremco Inc
CMI Energy
Deltak LLC
Duct Balloon
Multifab Inc
NEM USA Corp

Deaerators

ALSTOM Power Inc
CMI Energy
Deltak LLC
Indeck Power Equipment Co
NEM USA Corp

Duct burners

ALSTOM Power Inc
CMI Energy
Deltak LLC
Hamworthy Peabody Combustion
NEM USA Corp

Ductwork and liners

ALSTOM Power Inc
Bremco Inc
Chanute Manufacturing
CMI Energy
Deltak LLC
Duct Balloon
HRST Inc
Moran Iron Works Inc
NEM USA Corp

Emissions control systems

1 SCR systems
2 SCR catalyst
3 CO catalyst
4 CEMS
5 SCR reagent
6 Low-NOx efficiency improvement
7 Catalyst maintenance
8 Combustion dynamics production

ALSTOM Power Inc (1,2,3,4,6)
ATCO Structures and Logistics Ltd (1)
BASF Corporation (2,3)
CMI Energy (1,2,3,4,5,6)
Cormetech Inc (1,2)
CSE Engineering Inc (4)
DeepSouth Hardware Solutions LLC
Deltak LLC (1,2,3)
EmeraChem (1,2,3)
Express Integrated Technologies LLC (1,2,3)
Groome Industrial Service Group (7)
The Hilliard Corporation
HRST Inc (1)
Indeck Power Equipment Co (1,2,3)
Innovative Steam Technologies (IST)
Johnson Matthey Inc (1,2,3)
NAES Corp (1)
Nationwide Environmental Solutions (1,2)
NEM USA Corp (1,3,4)
Nooter/Eriksen Inc (1,2,3)
Precision Iceblast Corp
Rentech Boilers (1)
Siemens Energy (6,8)
Vogt Power International Inc (1,3)

Expansion joints

1 Hot-gas-path
2 Piping

ALSTOM Power Inc (1,2)
Bremco Inc (1,2)
CMI Energy (1)
Deltak LLC (1,2)
HRST Inc (1,2)
KE-Burgmann USA Inc (1,2)
Multifab Inc (1,2)
NEM USA Corp (1,2)
Power Support Inc (1)

Freeze protection

ALSTOM Power Inc
Bremco Inc
Everest Sciences Corp
HRST Inc
NEM USA Corp
Vogt Power International Inc

HRSGs

1 Drum-type
2 Once-through
3 Replacement pressure parts
4 Packaged fired

ALSTOM Power Inc (1,2,3,4)
Chanute Manufacturing (1,3)

CMI Energy (1,2,3)
Esco Tool (3)
Express Integrated Technologies LLC (1,3)
Deltak LLC (1,2,3)
HRST Inc (3)
Indeck Power Equipment Co (1,3)
Innovative Control Systems
Innovative Steam Technologies (IST) (2,3)
NEM USA Corp (1,2,3)
Nooter/Eriksen Inc (1,2,3)
Rentech Boilers (1,3,4)
Siemens Energy (1,2,3)
Vogt Power International Inc (1,3)

Instrumentation

ALSTOM Power Inc
CEC Vibration Products Inc
CMI Energy
CSE Engineering Inc
DeepSouth Hardware Solutions LLC
Deltak LLC
DRB Industries LLC
Emerson Process Management
Environment One
Ludeca Inc
Meggitt Sensing Systems/Vibro-Meter
Mettler-Toledo Thornton Inc
NEM USA Corp
Sentry Equipment Corp
Siemens Energy

Insulation

ALSTOM Power Inc
Chanute Manufacturing
CMI Energy
Deltak LLC
Mopac
Multifab Inc
NEM USA Corp
Vogt Power International Inc

Maintenance tools

ESCO Tool

Nitrogen generators

Parker Hannifin Corp

Professional services

1 Consultants
2 Contract maintenance
3 EPC
4 Performance assessment
5 CFD analysis
6 NDE
7 Piping system design/analysis

Advanced Turbine Support Inc (6)
Alimak Hek (2,3)
ALSTOM Power Inc (1,2,3,4,5,6,7)
Bibb Engineers (1,3,7)
Bremco Inc (2)
CMI Energy (1,3,4,5,6,7)
Cogentrix Energy LLC (2)
Creative Power Solutions (4,5)
CSE Engineering Inc (1,4)
Deltak LLC (1,4,5,7)
DRB Industries LLC
Bob Fidler Services Inc (1,2)
General Physics Corp (1,4)
Graycor Industrial Constructors Inc (3)
Hamworthy Peabody Combustion (4,5)
HRST Inc (1,4,5)
Indeck Power Equipment Co
Meggitt Sensing Systems/Vibro-Meter (1)
Moran Iron Works Inc (7)
NEM USA Corp (1,2,4,5,6,7)
Nooter/Eriksen Inc (1,2)
Olympus NDT (6)
Power Support Inc (1)
Precision Iceblast Corp (2)
Process Controls Solutions LLC (1)
Sargent & Lundy LLC (1,3,4,5,7)
Scientech (1,4)
The Shaw Group (1,3,4,7)
Siemens Energy (1,2,3,4,5,6,7)
TDC Filter (2)
URS Washington Division (1,2,3,4,6,7)
Vogt Power International Inc (4,5,6,7)
E H Wachs Co (7)

Scaffolding

Mopac
Precision Iceblast Corp

Software

1 Diagnostic
2 Optimization
3 CFD

ALSTOM Power Inc (1,2,3)
CMI Energy (3)
Emerson Process Management (2)
General Physics Corp (1,2)
Ludeca Inc (1)
Meggitt Sensing Systems/Vibro-Meter (1)
NEM USA Corp (1,2,3)
Scientech (1,2)
Strategic Power Systems

Stacks

Alimak Hek
ALSTOM Power Inc
ATCO Structures and Logistics Ltd (1)
CMI Energy
Deltak LLC
Duct Balloon
Innovative Steam Technologies (IST)
Moran Iron Works Inc
NEM USA Corp

Tubing

1 Finned
2 Smooth

ALSTOM Power Inc (1,2)
Chanute Manufacturing (1,2)
CMI Energy (1)
Deltak LLC (1,2)

Esco Tool (1,2)
Bob Fidler Services Inc (1)
NEM USA Corp (1,2)

Valves

1 Steam, stop/check
2 Steam, pressure let-down
3 Steam, safety
4 Steam, turbine bypass

ALSTOM Power Inc (1,2,3,4)
CMI Energy (1,2,3,4)
Deltak LLC (1,2,3)
The Hilliard Corporation
Innovative Control Systems (1,2,3,4)
Jansen's Aircraft System Controls
Mitsubishi Power Systems Americas (1,2,3,4)
NEM USA Corp (1,2,3,4)
Scientech

Water treatment

ALSTOM Power Inc
Aquatech International Corp
Graver Technologies
Leslie Controls Inc
NEM USA Corp
Pall Corp
Sentry Equipment Corp

STEAM TURBINE GENERATORS AND AUXILIARIES

Bearings/bearing repair

1 Journal
2 Thrust

ALSTOM Power Inc (1,2)
D-R Leading Edge Turbine Technologies (1,2)
Mitsubishi Power Systems Americas (1,2)
QinetiQ North America (1,2)
Roblicorp (1,2)
Sulzer Turbo Services (1,2)
TurboCare (1,2)

Blades and diaphragms

1 Repair
2 Replacement

ALSTOM Power Inc (1,2)
BASF Corporation
Creative Power Solutions (1,2)
D-R Leading Edge Turbine Technologies (1,2)
Liburdi Turbine Services Inc (1)
Liburdi Turbine Services LLC (1)
Mitsubishi Power Systems Americas (1,2)
NAES Corp (1)
Power Support Inc (1)
Praxair Surface Technologies (1)
Sulzer Turbo Services (1,2)
TurboCare (1,2)

Borescopes

Olympus NDT
Siemens Energy

Control systems and upgrades

ALSTOM Power Inc
Analysts Inc/Sovice Inc
CEC Vibration Products Inc
CSE Engineering Inc
DeepSouth Hardware Solutions LLC
D-R Leading Edge Turbine Technologies
Emerson Process Management
Innovative Control Systems
Meggitt Sensing Systems/Vibro-Meter
Petrotech Inc
Process Controls Solutions LLC
Siemens Energy
TurboCare

Cooling towers

Alimak Hek
DRB Industries LLC

Generators

1 Air-cooled
2 Hydrogen-cooled
3 Hydrogen monitoring/control
4 Repairs and rewinds
5 Load testing

Advanced Turbine Support Inc (1,2)
AGTServices Inc (1,2,4)
ALSTOM Power Inc (1,2,3,4)
Belyea (1,2)
CEC Vibration Products Inc
Cogentrix Energy LLC (4)
Cutsforth Inc (4)
D-R Leading Edge Turbine Technologies
Fulmer Company (4)
Indeck Power Equipment Co
Innovative Control Systems
NAES Corp (4)
National Electric Coil (1,2,4)
Pond & Lucier LLC (1,2)
QinetiQ North America (1,2)
Siemens Energy (1,2,3,4)
Sulzer Turbo Services (1,2,3,4)
TurboCare (4)

Instrumentation

ALSTOM Power Inc
CEC Vibration Products Inc
CSE Engineering Inc
DeepSouth Hardware Solutions LLC
Emerson Process Management
Environment One
Innovative Control Systems
Ludeca Inc
Meggitt Sensing Systems/Vibro-Meter
Mettler-Toledo Thornton Inc
Petrotech Inc
Roblicorp
Sentry Equipment Corp
Siemens Energy
Sulzer Turbo Services

Lube/hydraulic oils

1 Replacement oil
2 Additives
3 Conditioning
4 Filtration
5 Varnish removal

American Chemical Technologies Inc (1,2,3)
Analysts Inc/Sovice Inc (3)
The Hilliard Corporation (3)

ExxonMobil Lubricants and Specialties (1,3)

Hy-Pro Filtration (3,4,5)

ISOPur Fluid Technologies Inc (3,5)
C C Jensen Inc (3)
Pall Corp (3)

Maintenance tools

Esco Tool
E H Wachs Co

Professional services

1 Consultants
2 Contract maintenance
3 Condition assessment
4 EPC
5 Inspection
6 Outage planning
7 Performance assessment
8 Shaft alignment
9 Cleaning services
10 Machinery diagnostic services
11 Contract personnel

Advanced Turbine Support Inc (5)
AGTServices Inc (5)
Alimak Hek (2,4,6)
ALSTOM Power Inc (1,2,3,5,6,7,8)
Analysts Inc/Sovice Inc (7)
Bibb Engineers (1,3,4,7)
Cogentrix Energy LLC (5)
Creative Power Solutions (7)

CSE Engineering Inc (1,2,3,5,6,7)
Cutsforth Inc (1,2,5)
D-R Leading Edge Turbine Technologies (2,5,6)
DRS Power Technology Inc (1,3,5)
Environment One (1)
Esco Tool (6)
Bob Fidler Services Inc (2,6)
Fulmer Company (1,2,3,7)
Gas Turbine Efficiency (2,5,6)

General Physics Corp (1,3,7)
Graycor Industrial Constructors Inc (4)

Ludeca Inc(8)
Meggitt Sensing Systems/Vibro-Meter (1)
Mopac (3)
NAES Corp (2)
Olympus NDT (5)

Pond & Lucier LLC (1,5,6,8
Power Support Inc (1,5)
Precision Iceblast Corp (2)
Process Controls Solutions LLC
QinetiQ North America (5)
Sargent & Lundy LLC (1,3,4,6,7)
Scientech (1,3,6,7)
The Shaw Group (1,3,4,5,6,7)
Siemens Energy (1,2,3,4,5,6,7)
Strategic Power Systems (6,7)

Sulzer Turbo Services (1,2,3,5,6,7,8)
URS Washington Division (1,2,3,4,5,6,7)
E H Wachs Co (6)
Wood Group GTS (2)

Pumps

1 Boiler-feed
2 Circulating-water
3 Condensate

Belyea (1,2,3)
DRB Industries LLC (1,2,3)
D-R Leading Edge Turbine Technologies (1)
TurboCare (1)

Steam seals

ALSTOM Power Inc
D-R Leading Edge Turbine Technologies (4)
Sulzer Turbo Services
TurboCare

Steam turbines

1 Under 10 MW
2 10-50 MW
3 Over 50 MW
4 Repair and overhaul, field
5 Repair and overhaul, shop

Advanced Turbine Support Inc (1,2,3)
ALSTOM Power Inc (3,4,5)
Belyea (1,2,3)
Creative Power Solutions (1,2,3)
CSE Engineering Inc (1,2,3)
Cutsforth Inc (1,2,3)
D-R Leading Edge Turbine Technologies (1,2,3,4,5)
Bob Fidler Services Inc (4)
Innovative Control Systems
Leslie Controls Inc
Mitsubishi Power Systems Americas (2,3,4,5)
NAES Corp (4,5)

Pond & Lucier LLC (4)
Power Support Inc (3,4,5)
Process Controls Solutions LLC (2,3)
QinetiQ North America (2,4)
Siemens Energy (1,2,3,4,5)
Sulzer Turbo Services (1,2,3,4,5)
TurboCare (4,5)
Wood Group GTS (4,5)

Water treatment

1 Cooling water
2 Makeup
3 Sampling

Aquatech International Corp (1,2,3)
Graver Technologies
Jansen's Aircraft System Controls
Mettler-Toledo Thornton Inc
Pall Corp (2)
Sentry Equipment Corp (1,2,3)

Input from monitoring, inspections, tests critical for maintenance planning

Clyde V Maughan, Maughan Generator Consultants

There is increasing pressure to extend inspection/maintenance intervals for gas and steam turbines and their generators. One important approach to cycle extension has been predictive maintenance. However, predicting the maintenance requirements for a generator is a difficult task, because relatively little information on its health can be accessed by monitoring an operating unit.

Identified below are the three primary tools used to assess generator condition; each has important weaknesses.

- **Monitoring.** Several of the most common deterioration mechanisms are not monitored at all.
- **Inspection** has several limitations, including: (1) the need to disassemble components, (2) many areas are inaccessible for inspection even with state-of-the-art diagnostic equipment, (3) the quality of the assessment is highly dependent on the technician's skills.
- **Tests.** Each of the many tests available to a generator owner/operator has one or more limitations. Examples: (1) cannot identify local areas of weakness without risk of insulation breakdown, (2) provides average results only, (3) insensitivity to vital deterioration mechanisms, (4) requires specialized equipment, (5) hazardous to personnel.

Monitoring

Generator stators and fields historically have been monitored by relatively unsophisticated instrumentation. These standard devices, even when supplemented by state-of-the-art instrumentation, do not detect many common modes of failure, including the following:

- Stator-bar vibration without partial discharge or vibration sparking.
- Stator-bar strand-header water leaks.
- Developing cracks in stator-bar connections.
- Field coil/turn distortion.
- Forging cracks.

Unfortunately, equipment capable of detecting these problems does not appear forthcoming. Thus, predictive maintenance will remain based on financial considerations, rather than on the actual condition of the generator. However, if inspection and tests are conducted judiciously, a good assessment of generator condition generally can be accomplished.

1. Stator end-winding vibration sensor is mounted on a winding series connection

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

Equipment

Stator end-winding vibration is one of the most common deterioration mechanisms affecting large generators. Machines suspected of having excessive end-winding vibration can be monitored with detectors relatively new to the market (Fig 1). These devices have no electrical conductors and can be safely placed on the high voltages existing on stator-bar surfaces.

The instrument measures actual vibration levels and tracks changes in vibration magnitude over time. This information is valuable for determining when an outage should be scheduled. Preliminary data suggest that 3 mils may be the upper limit for a long-term safe vibration level.

Partial discharge (PD) exists on virtually all stator windings. While it tends to be a very slow deterioration mechanism on mica insulation, PD is a good telltale for several common deterioration modes—including stator-bar vibration in the slot and some forms of contamination. With good PD sensors and monitors, useful data can be captured. However, interpreting the significance of those data and eliminating "noise" continue to be the most difficult aspects of PD testing (Fig 2).

Testing-company approaches to PD data analysis are not standardized. One major 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.

Stator-winding RTDs and TCs. Many owners want to operate their generators based on winding temperatures. Two thoughts here: (1) The information obtained from a winding-slot RTD is related only peripherally to actual copper temperature; (2) temperature is only a secondary cause of generator deterioration.

Regarding the first point, the RTD reads a "composite" temperature of cooling gas, core iron, and winding copper through an insulating blanket (the groundwall insulation). RTDs and TCs positioned to read the temperature of the cooling medium discharged from a direct-cooled bar offer a better measure of temperature, but give only indirect guidance as to copper hot-spot temperature.

Slot RTDs offer no useful information regarding insulation deterioration on water-cooled windings. But they can provide some guidance relative to buildup of internal contaminants (and partial plugging) within the hollow strands.

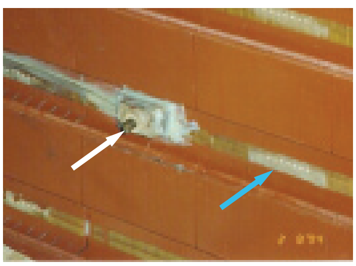
Generator condition (core) monitor. This equipment monitors a generator for any source of excess temperature—including several important deterioration mechanisms related to localized problems (Fig 3). These include core lamination shorts, failing electrical connections, and plugged ventilation circuits.

With the addition of temperature-sensitive paints, the core monitor can give a general indication as to where a problem may be occurring. Although monitors made prior to about 1990 were prone to false-positive alarms, later models are more reliable and their alarms should be investigated.

Field flux probe. Equipment for detecting field-turn shorts has been available for 60 years, but it has gained general acceptance and use only in the last 25. The flux probe is a simple device (Fig 4, white arrow), but the test takes time to do correctly.

Testing requires plant operators to vary generator load over a specific range

3. Condition monitor identifies any source of excess temperature



4. Flux probe (white arrow) is highly reliable and can determine the precise coil where a short exists. The green arrow points to seven holes in the wedge for measuring radial spring compression height, which is indicative of the wedging force on the stator bar of kilowatts and kiloVArs. The flux probe is inexpensive and accurately identifies the number of turn shorts in each coil; it has little exposure to error or ambiguous readings. Every generator of importance should have a flux probe installed on its stator.

Field vibration. One of the more common problems associated with fields is that of "thermal vibration vectors"—that is, vibration related to the magnitude of the field current.

To assess the impact of a thermal vector on a field, vibration magnitude and angle must be measured. Having both it is relatively easy to determine the length and angle of the thermal vector. With this information, rational determination of corrections can be made, and some information as to root cause of the vibration usually can be obtained.

Field ground detection. This is standard equipment on generators and should be monitored continuously. Because either single or double field-ground conditions can be hazardous to personnel and equipment, the unit should be brought offline immediately in the event of a confirmed field-ground alarm. For a field known to be in poor condition, an immediate trip may be advisable.

The field-ground device offers no information as to where the ground might be within the field, or external to the field. This can be determined with two simple tests:

- Location of ground within the winding can be obtained by flowing a relatively small current through the winding and measuring voltage to ground from each end of the winding.
- The axial location in the field body can be found by flowing a larger current from end-to-end on the field forging, and accurately measuring the point at which voltage from the winding to the forging passes through zero.

Inspection

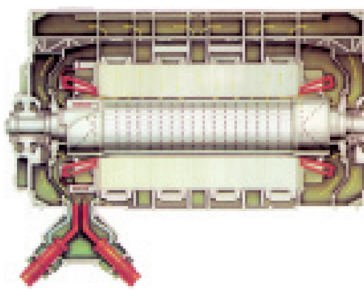
Inspection probably is the most powerful generator condition-assessment tool, when it is done properly. The process has several limitations, including these: many areas cannot be seen, even with the best tools (robots included); inspection can be time-consuming; results are qualitative and highly technician-dependent.

Inspection teams rely on the fact that many of the prevalent deterioration mechanisms leave tell-tale signs of trouble, including: dust, dirt, grease, fretting discoloration, displacement, cracks, foreign objects, deformation, and distortion. But evidence may be subtle and limited, particularly in the early stages.

Because inspection is inherently difficult, and judgment often is required to rate the significance of the evidence, the work must be performed by a qualified individual or team for the results to be complete and reliable. Training and experience are important, and on new or more complicated phenomena, knowledge of generator design may be indispensable.

Accessibility

Field in place. Fully assembled generators typically (1) allow little access for inspection and (2) provide little information as to generator condition (Fig 5). Some machines, particularly air-cooled units, have ports that allow good access for inspecting the outside diameter (OD) of stator endwindings



5. Inspection access in an assembled generator is limited as the cross section of a typical unit attests

6. Air-gap robot typically carries a camera and wedge-tapper device

7. Advanced partial discharge activity is in evidence on bar surface

and the connection rings—an important deterioration area.

Removal of coolers and the inner and outer top-half end shields (bearing brackets) allow use of mirrors, borescopes, and miniature video cameras to possibly access retaining rings, field end wedges, core end iron, and stator end wedges.

Robotic equipment can traverse the entire length and circumference of the air gap in most generators—even ones with gap baffles (Fig 6). These robots typically carry a camera and wedge-tapper device.

They facilitate assessment of many vital generator parts and deterioration conditions, including: stator bar vibration, stator and field wedges, stator wedge tightness, stator core, air-gap baffles, core ventilation ducts, and radial-spring ripple height on some wedge designs.

8. Spark damage caused by vibration is seen in ventilation duct through a borescope

When making a go/no-go decision on robotic inspection, keep in mind that it is both expensive to perform and likely to uncover a problem that would require field removal anyway.

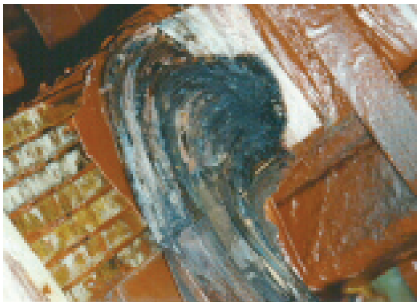
Field removed. A "complete" stator and field inspection requires field removal. Direct access is provided to surfaces such as stator end-windings, vent ducts via borescope or very small flashlight, and under retaining rings with borescope and mirrors. Examination of stator bars is improved, allowing more accurate evaluation of the critical mechanisms of bar vibration and PD.

However, even with the field removed, there remain many inaccessible, but important, inspection locations, including: much of the field winding under the wedges, sides of the stator bars in the slots, core iron beyond the inner surfaces, most of the field winding under retaining rings, internals of the stator-bar insulation, etc.

Stator winding

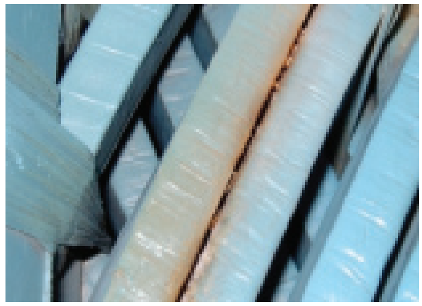
The slot portion of the stator winding is critical, but the areas of greatest interest are behind the wedges and iron core—and inaccessible. Direct view of the bar surfaces is limited and the effects of PD and/or vibration sparking are not possible to determine on many windings. Removal of selected wedges may allow access to important conditions (Fig 7).

On generators with radial core ventilation ducts, borescopes can give good access to the sides of the bars at the ducts. But the distortion inherent in borescope viewing may make difficult the interpretation of



9. Failing series connection was identified on stator end windings

10. Foreign-object wear has left bare copper exposed



11. Partial discharge attack is in evidence at line-to-line phase break

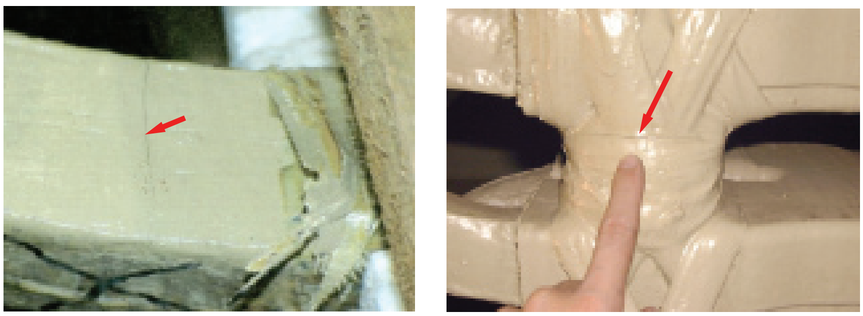
what's being seen (Fig 8). Once again, the technician's skill and experience are critical to inspection success.

It's important to manage your expectations: Inspection of the slot portion of a winding often leaves one with an uncertain feeling as to the quality of the winding.

Stator end windings are much more accessible than the slots, and failing connections can be observed (Fig 9). Dust or grease deposits may indicate vibration or foreign objects, but the extent of damage, if any, may be difficult to assess (Fig 10).

PD activity can cause several conditions that are detectable by inspection (Fig 11). The numerous indications on the endwindings may add to the uncertain feelings resulting from inspection of the slot portion of the winding.

Mechanical damage. Where a generator has been subjected to short-circuit or mis-synchronizing incidents, the winding will have experienced high mechanical forces. The tiny cracks that may be seen in an endwinding after such an incident are easy to overlook (Fig 12). Observed cracks may simply have resulted from normal differential expansions within the endwinding (Fig 13). Visual inspection alone might not be sufficient to assess the extent of winding damage.

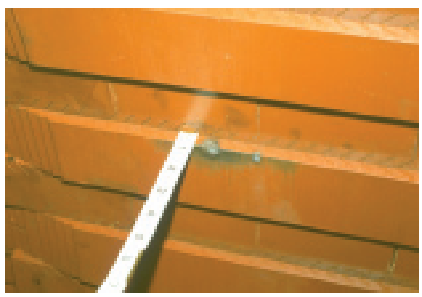


12, 13. Comparing the tiny, but fatal, crack in insulation groundwall at the left with the inconsequential crack from differential expansion at the right illustrates why you want top talent inspecting your generator

Stator core and frame

General deficiencies. Most core deficiencies can be observed from the core's inner surfaces, but the defects sometimes can be so small as to be virtually invisible to all but the skilled inspector conducting a close examination.

If heavy contamination is found on the core ID and in ventilation ducts, inspectors should determine the source and nature of the contamination to facilitate corrective action. Careful inspection, combined—where appropriate—with core flux tests should give a good assessment of core condition.



14. Significant core damage above could be overlooked by the untrained eye

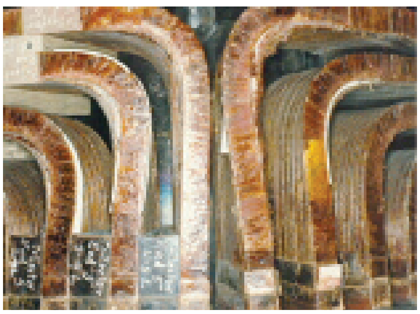
Core mechanical damage, looseness. Mechanical damage covers a broad spectrum. Minor faults typically appear as small, local areas


15. Looseness usually occurs at the inside diameter near the ends of the core

of solid-metal surface or of scorched lamination paint (Fig 14). They are easily overlooked if inspection is not thorough.

By contrast, severe mechanical damage is easy to spot. It may be caused by core looseness, foreign objects, improper wedging, or careless field assembly and removal. Looseness usually occurs at the inside diameter near the ends of the core, where it is easy to identify (Fig 15). Look for dust generation, punching and spacer movement, or small pieces of punchings that have cracked off.

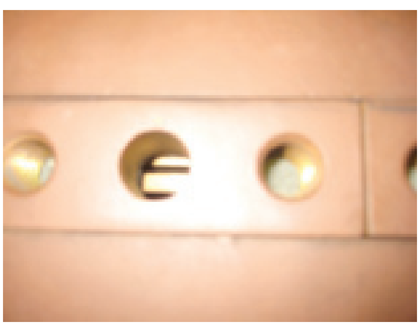
But while you have good access to core surfaces, keep in mind that there may be issues deep inside the core. This means it's not possible, ordinarily, to accurately assess core condition by visual inspection alone.


16. Significant coil/turn distortion is evident with the retaining rings removed

Field inspection

Field windings are difficult to inspect without some disassembly, making it challenging to assess the actual condition of windings in most machines. Numerous problems may be occurring, including: coil displacements or deformation (Fig 16), turn displacements, contamination build-up, turn and slot insulation displacement and cracks, shifted or missing blocking and baffling, and arcing or burning between conductors (coils, turns, leads) and ground.

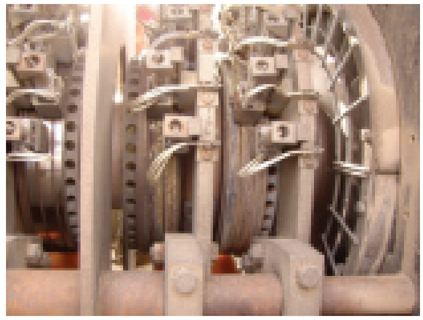
However, access is improved dra-



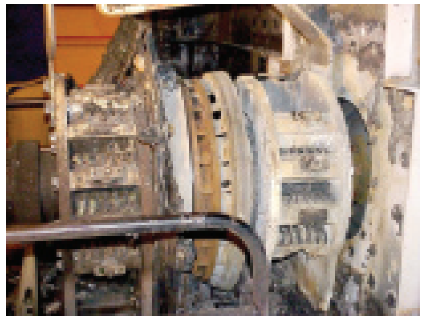
17. Inspection via ventilation holes in the wedges is possible on direct ventilated fields

matically by removal of the retaining rings. Inspection after this step can be quite complete. Also, keep in mind that on direct ventilated fields, inspection can be made through the ventilation holes in the wedges on the body portion of the field (Fig 17).

Collector/brushholder rigging. Ongoing inspection and maintenance are vital on these components, which probably are the source of more forced outages than any other generator component. If failure occurs, the condition may be correctable with modest effort, but it also may result in an outage of several month's duration.



18. Arc damaged rings on only one polarity of brush-holder rigging



19. Catastrophic failure was caused by a flashover between polarities

To illustrate: The arc damage in Fig 18 may be repairable by grinding the affected rings and replacing the burned brushholder components; this could take anywhere from several days to a week.

In Fig 19, rotating components appear close to failure. Situations such as this are conducive to severe plant damage and to injury or death of personnel. At a minimum, repairs will require replacement of the entire collector assembly and brushholder rigging. But if the field forging also is burned, costly and time-consuming forging repair may be required. Outage time could be weeks or months.

Tests

Each of the many tests that can be conducted to evaluate a generator's condition has one or more of these limitations:

- Cannot find local discrete weak areas without risk of insulation breakdown.
- Gives average results only.
- Insensitive to vital deterioration mechanisms.
- Requires specialized equipment.
- Personnel hazard.

A variety of tests is used in offline evaluation of generators. Most are common to all types of machines, but some are used on specific classes of generators. The majority has been used since the infancy of power generation, but a few are of more recent development. Most of the tests are benign and will not harm the component under test. The primary exception: over-voltage testing.

Precise evaluation of a generator's condition is difficult even under the best conditions. But if the full battery of tests described here is used, important assessment of equipment condition can be obtained.

Special considerations. Because the over-voltage test is so valuable an evaluation tool *for stator windings,* and because owners often are reluctant to allow its use, the merits of this test are worth reviewing.

Most plant supervisory personnel are aware that stator insulation systems deteriorate at a modest rate, and unless subjected to poor O&M practices or localized distress, they should serve for 30 to 40 years—or longer. They also know that during every type of over-voltage test, there is the possibility of failure to ground.

But many plant decision-makers are unaware that (1) failure almost never occurs during a properly conducted over-voltage test unless severe stator-winding degradation already has taken place, and (2) a good stator winding insulation system is not measurably degraded during the application of over-voltage.

There are no industry standards specifically addressing maintenance high-potential (hipot) testing of stator windings. OEMs often recommend an in-service test value of 1.5E (E is the line-to-line voltage), although some are reluctant to over-voltage test at all.

The recommendation to test is based on the knowledge that bars failing the test invariably show severe insulation degradation attributed to operation. Note that new insulation will hold roughly four times the highest maintenance over-voltage values recommended.

There always is the possibility of winding failure during an over-voltage test. When this occurs, it often is not possible to make a local repair of the failed area. Thus, unless previous preparations have been made (spare parts, repair personnel, outage time scheduled), a major outage extension may occur.

Hipot testing is a particularly important evaluation tool for a stator with general and serious deterioration. This is true because the first failure is likely to be at a location in the winding near the line-voltage end—but at line-to-neutral voltage. The first failure will place the line end of the other two phases near line-to-line voltage to ground and thus overstress weak bars in these locations.

Should a second failure occur on the winding, extremely high current will flow through the faults. The resultant burning will be severe, and the current cannot be interrupted until the field voltage has decayed. The time constant for a typical field is about 5 seconds. Thus, it may take 5 to 10 seconds for the field current to decay to a level that will extinguish the stator winding arc.

Double-winding failures have occurred on a significant percentage of stator windings in generally poor condition that have failed to ground in service; each case resulted in full stator and field rewinds, extensive cleaning, and, oftentimes, partial core restacking.

In reaching the basic decision relative to performance of stator hipot tests, the owner is faced with divergent and conflicting alternatives: Perform a suitability-for-service high-potential test and risk stator-winding failure, or omit the hipot test and accept increased risk of service failure, forced outage, possible extensive machine damage, and a long unplanned outage. In the final analysis, depending on the importance of a particular machine to the system, and other business and economic factors, judgment must be made between these two options.

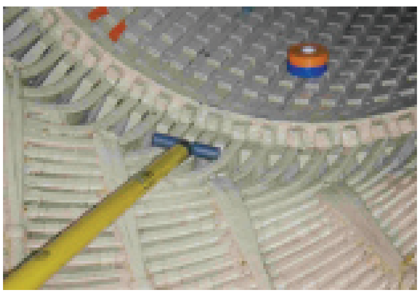
Equipment selection. The most effective electrical-test evaluation tool for the quality of a stator winding is the hipot test. The choice of test-voltage source is of secondary importance; all three commonly used systems are effective: power frequency ac, 0.1Hz ac, and dc.

The dc value accepted by the industry is 1.7 times the 60-Hz rms value. (Actually, there is not a simple, direct relationship between the two types of voltage. Laboratory comparison tests have shown values as low as 1.414 and as high as 4.0. The 1.7 multiplier is an acceptable compromise.)

Caution: Maintenance over-voltage testing generally is not recommended for fields. The 500-V megohmmeter provides sufficient voltage for testing the low-voltage field.

PD offline test

Several types of offline tests are used to locate PD sites within a stator winding and to assess its magnitude at each location. They rely on a PD-free source to apply a



20. Individual bars are probed for PD activity

selected high voltage—generally the line-to-neutral voltage of the stator winding. Thus all portions of the winding are at the test voltage and there are no electromagnetic forces on the bars.

Note that there have been rare cases of winding failure at this relatively low voltage. In every case, the winding was in an extremely advanced state of degradation.

There are limitations in the validity and interpretation of the information acquired during PD offline tests. Trend review and comparison to duplicate windings may be of greater value than analysis of absolute readings. No industry standards exist on data analysis.

Online test sensor. The sensors and analytical instrumentation used for online testing can be used for offline tests as well. The same challenges exist with respect to signal collection and interpretation, except that there are far fewer spurious signals offline.

The following general principles apply to interpretation of results:

- Readings above 5000 pC (picocoulombs) may be indicative of winding deterioration.
- Equal distribution of positive and negative pulses may indicate there are voids within the stator-bar groundwall insulation.
- A preponderance of positive pulses may suggest voids on the outside surface of the insulation.
- Predominance of negative pulses may indicate voids at or near the copper.

Individual bar probes. Both radio-frequency and ultrasonic probes are used (Fig 20). The individual bars are probed in the areas of the endwinding and in that portion of the slot that is accessible safely. Readings are taken of any active site; most useful data are obtained at locations of high PD activity.

Don't underestimate the considerable personnel safety hazards associated with use of a probe for PD testing. Be sure all personnel are properly equipped and trained before allowing them to participate in this activity.

General stator, field testing

Several other tests also are used to evaluate field and stator insulation systems. The most significant of these are summarized below.

Megohmmeter. The insulation resistance value indicates overall insulation integrity, and may identify a fault that responds to relatively low voltage. But contamination, particularly with a conductive material or in the presence of moisture, may result in a low megohmmeter insulation resistance reading on a very good insulation system.

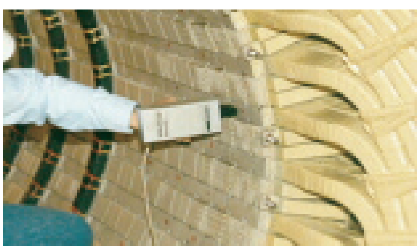
Polarization index (PI)—the ratio of the 10-min megohmmeter reading to the 1-min reading—is indicative of the extent of dirt and moisture contamination. If the insulation is dry, PI tends to be high—in the range of 1.5 to 4.0. If the insulation is damp—internally or externally—flow of electrical current will be high and predominately resistive; a PI reading of 1.5 to as low as 1.0 can be expected.

Megohmmeter readings vary from machine to machine, or on a given machine over time. Judgment is required to interpret the megohmmeter resistance and PI values, which often dictate maintenance actions—such as winding cleaning and drying.

Power factor and PF tip-up. Power-factor testing is perhaps the most common elevated voltage test performed on stators (often under the name "Doble testing"). While the test itself is quite straight forward, interpretation is not.

It is popularly believed that power factor and tip-up relate closely to winding condition, and often this is not the case. More likely, surface contamination and moisture are responsible for high tip-up values, and perhaps high power-factor values as well. On the other hand, very low values may not be indicative of good insulation system quality.

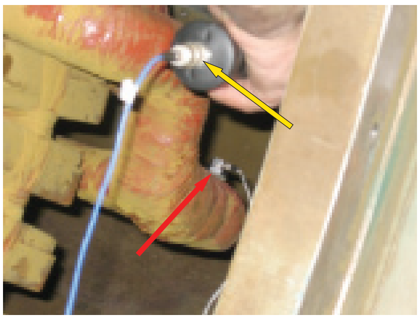
Power-factor and tip-up tests are useful and worthwhile to perform. But the test results only can be relied on as a guide, rather than as an absolute measure of system condition. High, low, and "optimum" readings



21. Hand-held tapper checks tightness of stator wedges can be associated with insulation systems in good and in bad condition.

Stator wedge tightness. Historically, tightness has been checked with a small (2 oz) ball-peen hammer. While inherently subjective, with some experience and training, a competent technician can make an accurate judgment of wedge tightness. More recently, acoustic and mechanical test devices have been developed and are in wide use (Fig 21).

Mechanical testers also are available on robot carriers capable of checking wedge tightness without removing the field. Mechanical testers provide quantitative data that can be monitored over time for trends. However, the validity of these test devices requires that the devices be properly calibrated; otherwise, the device might indicate that a tight wedging system is loose. Test results from a mechanical tester always should be confirmed by hand-tapping a few wedges.



22. Bump tests are suggested for in-service stator endwindings experiencing vibration problems. Yellow arrow points to impulse hammer, red to pick-up

Resonant frequency test. Stator endwinding resonant frequency tests are used to assess resonant frequencies and the looseness of endwindings and connections. "Bump" tests commonly made on new windings are vital for in-service stator endwindings experiencing vibration problems, or ones that have been repaired (Fig 22).

The tests require specialized equipment and trained personnel. Interpretation of results can be challenging. In general, test resonant frequencies should be higher than double power-system frequency by at least 20 Hz—that is, 140 Hz for 60-Hz systems.

Bearing insulation. The condition of bearing and hydrogen-seal insulation must be determined as well. Test voltages will be low; stable resistance values of more than 1 megohm are satisfactory.

Winding-copper resistance (field and stator). Off-spec resistance values are uncommon. But because the changes in resistance values over time are important, they should be recorded regularly.

An out-of-range high reading on the stator may indicate failing connections, a serious condition that requires investigation. The same is true for fields. Low field readings usually are associated with turn shorts. Low stator readings are unlikely. Theoretically, they would indicate shorted turns, but a shorted turn would have failed the winding in service and would not have been found by test.

RTD/TC calibration. It's important to verify the accuracy of RTD/TCs regularly and to calibrate them as required. The data they provide is critical for trending generator performance over time.

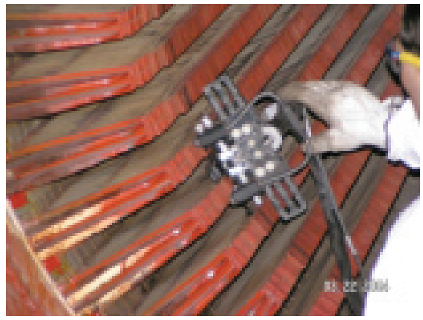
In general, a high in-service reading from a specific temperature device likely reflects an instrumentation problem. But a true out-of-range reading may indicate very serious component distress.

When a generator has been offline for an extended period, a good way to check the accuracy of these devices is to simply compare readings among them. All data should be in a fairly tight band with no significant discontinuities in the pattern.

Stator core tests

Testing of core insulation is essential because inspection alone may not reveal all the issues. Core tests also can help (1) characterize known problems, (2) clear up any doubts regarding inspection findings, and (3) confirm that no damage was done during maintenance work that directly or indirectly involved the core—such as stator rewedging, bar replacement, etc.

These tests are not simple and should be performed by experienced, qualified personnel with top-quality equipment. Two types of tests are used: low- and high-power. Both have significant weaknesses.



23. ElCid search coil and trolley searches for core problems

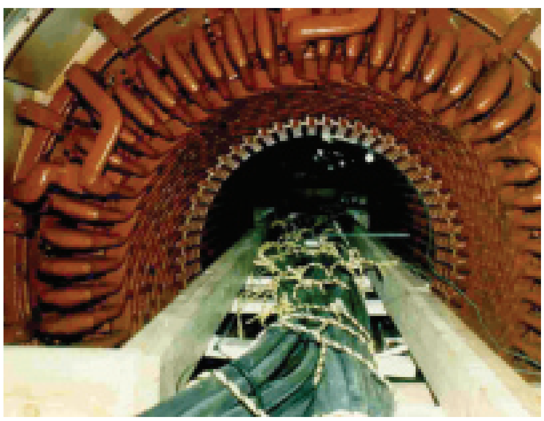
Low-power lamination insulation test. The most common low-flux test today is conducted at about 4% rated flux density using an electromagnetic core imperfection detector—the so-called ElCid test. The advantages of this test are several, including: equipment cost is low, setup is short and simple, quantitative results are obtained, and data generally are repeatable. Additionally, and perhaps most importantly, there is no hazard to the equipment and little personnel safety risk (Fig 23).

As noted above, all tests have their weaknesses. Among ElCid's disadvantages are its insensitivity to damage deep in the core and the need for special equipment to get accurate readings on the step-iron at the ends of the core. Also important: Correspondence between high ElCid values and core quality may be uncertain.

Overall, ElCid is a valuable test. However, it is not a sufficiently powerful tool on its own to justify restacking of a core—regardless of data quality and the capabilities of those performing the tests. If questionable results are obtained, a high-flux test should be performed.

High-power lamination insulation test. Most often called the "ring" or "loop" test, this test is characterized by its time-consuming setup, need for a long length of high-amperage unshielded cable, and costly power source requiring heavy breakers and controls (Fig 24). It also has inherent personnel and equipment safety risks.

Thus the ring test usually is not performed unless inspection and/or a low-power test suggests the core is defective. The bottom line: A well-performed core inspection, combined with unsat-



24. Excitation coil is arranged for high-flux test isfactory results from a properly conducted high-power test, raises serious concerns about core health and may warrant core iron replacement.

Liquid-cooled winding tests

Liquid-cooled stator windings have thousands of brazes, welds, and other connections where leaks can develop. Several tests can be used to verify the integrity of joints. Rigorously applied, these tests can give high assurance that the system is generally tight.

However, the tiny leaks associated with strand headers may not be found with any of the leak-test methods in use today, and these leaks may wet and irreparably damage the stator-bar groundwall insulation.

Such damage can be identified by methods for detecting wet insulation—including capacitance testing and instrumentation that directly measures the water content of wet insulation. Both methods are subject to error, and a winding should not be condemned without having highly reliable data for decision-making. Before deciding to repair or replace a winding, be sure to take readings with the field removed and to thoroughly inspect areas where wet insulation is suspected.

Field forging tests

Nondestructive examination (NDE) techniques are used for assessing field forging and retaining-ring forging condition. But careful visual inspection is essential for recording gross evidence of concern, including: visible cracks, fretting, movement on shrink fit, etching, burning, rust (on magnetic rings), and mechanical damage (Fig 25).

25. Minor indications are highlighted on the retaining ring after NDE

The take-away

Accurately predicting the timing and scope of all needed maintenance on an operating generator is not possible with the present state-of-the-art of generator monitoring, inspection, and testing.

However, skillful use of all available knowledge can minimize the maintenance cost required to maintain a high level of reliability. To accomplish this goal, good O&M records are vital, as well as attention to all available information from monitoring, inspection, and testing activities.

Prudent to keep in mind is that even with best-in-class monitoring systems, generators remain with little or no detection capability for several common and serious deterioration and failure mechanisms—such as those identified at the opening of the monitoring section on p 134.

A vital point: While inspection and test of generators is challenging enough a task, correctly diagnosing the root causes of new and more subtle failure mechanisms can be much more difficult. In general, OEM onsite service personnel are trained in inspection, test, and repair of generators; they normally are not trained in diagnostics.

Failure to retain qualified experts for root-cause investigations means quality, timeliness, and cost of repair (as well as equipment reliability) may suffer greatly. Invalid root-cause determinations are believed responsible for annual losses of many tens of millions of dollars industry-wide.

Finally, extension of inspection/maintenance intervals should reflect all the information available for a specific generator, including: operating duty and hours, importance of the unit to the system, and condition assessment using all of the pertinent tools discussed above. The historic "five years between inspections" may not be appropriate. On the other hand, an arbitrary and long period between overhauls may result in neither reliable life nor low maintenance cost. 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.

Close collaboration between OEM, users facilitates issue resolution

Owner/operators of W501G (SGT6-6000) gas turbines manufactured by Siemens Energy meet face-to-face twice annually to share experiences with one another and with the OEM's engineers. The G fleet totals 24 units at a dozen sites in the US and one in Mexico (Sidebar 1).

What's particularly interesting about this user organization is that its small size, capable leadership (Sidebar 2), and collaborative nature allow it to think and act as a unit, facilitating problem-solving at the deck-plates level and with the OEM. Interesting, too, is that while other gas-turbine user organizations attract perhaps one attendee for every two to three machines in their respective fleets, the G users get about one and a half attendees for every engine.

501G USERS GROUP

2011 ANNUAL MEETING

February 14-18
Paradise Point Resort & Spa
San Diego, Calif

This is a proud group of engineers and technicians who have "grown up" together—so to speak—and understand each other's perspective. The first G, installed by Lakeland Electric, began commissioning operations in April 1999, but COD wasn't until March 2001—only one month before the second machine began commercial operation at Millennium. These people know each other, and each other's plants, well.

Most user-group meetings host roughly one-third to one-half first-timers, so many discussions are similar from year to year because newcomers have to be brought up to speed. There's not much turnover in the top positions at G facilities which means each meeting

1. 501G fleet: Two-dozen units strong

Siemens Energy's 501G fleet comprises 24 operating units. Two companies—Competitive Power Ventures Inc (CPV) and GDF Suez Energy Generation NA Inc—own seven units each, four own two each, two own one each. Here's a list of the plants in alphabetical order; owners are in footnotes under the list:

- AES Ironwood LLC, Lebanon, Pa (two units)
- New Athens Generating LLC, Athens, NY (three units)[1]
- Choctaw Gas Generation LLC, Ackerman, Miss (two units)[2]
- Ennis-Tractebel Power Co LP, Ennis, Tex (one unit)[2]
- Granite Ridge Energy LLC, Londonderry, NH (two units)
- New Harquahala Generating Co LLC, Tonopah, Ariz (three units)[1]
- Hillabee Energy Center, Alexander City, Ala (two units)[3]
- Hot Spring Power Co LLC, Malvern, Ark (two units)[2]
- Lakeland Electric, Lakeland, Fla (one unit)
- Magic Valley Generating Station, Edinburg, Tex (two units)[4]
- Millennium Power Partners LP, Charlton, Mass (one unit)[1]
- Fuerza y Energia Naco-Nogales SA de CV (FENN), Agua Prieta, Sonora, Mexico (one unit)[5]
- Wise County Power Co LP, Poolville, Tex (two units)[2]

[1]CPV [2]GDF Suez [3]Constellation Energy Inc [4]Calpine Corp [5]Union Fenosa

2. Steering committee

Chairman: Steve Bates, plant manager, Wise County Power Co LP

Vice Chairman: Mark Winne, plant manager, Millennium Power Partners LP

Kevin Robinson, Lakeland Electric

Ken Daycock, plant manager, AES Ironwood LLC

Dan Jorgenson, maintenance manager, Granite Ridge Energy LLC

Scott Wiley, manager of fleet maintenance, GDF Suez Energy Generation NA Inc

Bill Wimperis, director of project management, Constellation Energy Inc

Gregory McAuley, VP turbine maintenance group, Calpine Corp pretty much picks up where the last one left off, especially regarding the OEM's presentations. This certainly contributes to presentation efficiency because there's a minimum amount of repetition.

To illustrate: At the 2010 annual meeting in Orlando last February, Siemens presentations covered R4 vane deflection, R1 ring segments, R4 blades, exhaust systems, and rotor through bolt among the dozen or so issues of interest. Updates on each of those areas were featured at the abbreviated mid-year meeting at Siemens' Orlando offices in September.

Approximately half of the presentation/discussion time at 501G meetings is earmarked for users only. At the annual meetings, where exclusive G content spans three and a half days, most plants in the fleet make at least one presentation. Last February, for example, there were several presentations on the commissioning of the Hillabee Energy Center, which had been mothballed before its purchase by Constellation Energy Inc.

Other owner/operators presented on low-load CO, retubing and repairs of rotor air coolers, impact of corrosive insulating oil on transformers, water hammer, outage experiences, fleet quality findings, dehumidifier performance, etc.

Two presentations from the 2010 annual meeting that stand out in terms of value for owner/operators of all large frames, regardless of the OEM, concerned heat-recovery steam generators. One, by Nooter/Eriksen Inc, Fenton, Mo, focused on HRSG design/operational issues and recommended modifications, the other by Millennium Power Partners LP, Charlton, Mass, concerned an LP economizer modification to reduce gas-path backpressure. More on HRSGs later.

User presentations typically are posted on the group's website, which can be accessed through www.users-groups.com by registered members. If you qualify for membership in the organization but have not yet joined, this also can be accomplished on the website. Siemens presentations are accessible by owner/operators of the OEM's frames who apply for and are registered to access the manufacturer's Customer Extranet Portal.

A joint effort

How the OEM and its G customers work together serves as an example for others. To better understand the synergy, the editors talked to Siemens Frame Owner Mark Carter and Mark Winne, plant manager at Millennium and the 501G User Group's vice chair. Winne was a founding member of the user organization.

W501Gs have accumulated over 738,000 operating hours (as of October 2010) since their commercial debut in 2001 and they consistently receive the highest dispatch ratings of all gas-turbine models in Siemens' North American fleet. However, the engine has had its share of issues—including compressor wear between the stator vanes and compressor casing.

When this issue surfaced, Siemens worked with users to develop a cross-platform solution, which included the merging of Siemens and Westinghouse technologies in the field. Owner/operators closely followed the development and testing of the modification, enabling its timely acceptance by the user community and integration into the fleet.

Background. In mid 2003, the Siemens W501F fleet began receiving reports of wear on some compressor stator vanes; later, such wear was reported on some Gs. Observations of wear on the W501Gs may have been delayed because of attention to a different issue, prior to 2004, that required parts replacement on the first three rows of compressor stator vanes.

Inspections in 2004 revealed diaphragm hook wear in rows 4, 5,

1. Redesigned W501G compressor incorporates features of Siemens' V-style machine to address wear issues (left)

2. Testing program for the new compressor required nearly 1000 instruments to verify the performance and integrity of each component (right)

and/or 6 on some G machines. Siemens initiated a program to define the root cause and to develop an improved compressor. The maintenance interval targeted for the compressor modifications, and the length of the outages required to implement the mod, made it imperative that Siemens and its customers work together.

During the program, members of the 501G Users Group steering committee, representing owners of 23 of the 24 engines in operation, were invited to Siemens' Orlando engineering offices to review its findings in the matter and to verify that those findings were representative of what the users themselves were seeing on their units.

Winne told the editors that the opportunity to sit down with the OEM and discuss openly and frankly both the problem and possible solutions was a "unique experience" for a user. Both Siemens and the steering committee worked together to investigate the various aspects of the root cause to arrive at a common understanding of the issue.

Siemens maintained close contact with customers as its engineers arrived at conclusions regarding root cause and as the company worked through the development phase of the modification effort. The OEM determined that certain features of its successful V-style compressor for the SGT5-2000 and SGT5-4000 gas turbines would address the wear observed on the W501Gs.

Siemens once again invited the steering committee to Orlando to review its progress. After reviewing data, the users agreed with the OEM on the V-style compressor approach. Lead engineers on the compressor effort, Tom Gordon and Dave Wasdell, facilitated collaboration, enabling the setting of design targets and goals to satisfy a wide spectrum of stakeholders.

Installation of a V-style compressor in a gas turbine designed by Westinghouse was the first of several opportunities for merging Siemens and Westinghouse technologies in the W501G operating fleet. Siemens began procurement of hardware based on broad confidence in the proposed improvement by both the OEM's engineering team and the users.

It's important to note that collaboration of users and Siemens did not end with completion of solution development. The steering committee also was invited to Siemens' Hamilton (Ontario, Canada) facility to witness the first parts being manufactured for validation testing. Next step was to identify the first validation site.

Winne realized the potential benefit of moving ahead early with the redesigned compressor and the Millennium staff worked closely with Siemens to develop an 18-month program to install, test, and validate the design. Once the parties agreed in principle, a collaborative effort of detailed planning and logistical coordination was pursued to manage the significant potential risks associated with possible program and schedule upsets.

Siemens invested in a full rotor (Fig 1) and conducted an extensive testing program—one involving 952 instruments on both stationary and rotating parts in rows 1 through 13. The rotor was fitted with a slip ring to route instrument readings on rotating parts to monitors outside the machine.

Winne recalled that when testing began, the plant site looked more like a NASA mission control center (Fig 2) than a powerplant, with teams of engineers monitoring banks of computers and monitors arranged to gauge and verify the performance and integrity of each component in the new compressor. The benefit of the comprehensive evaluation program was that Siemens could verify that the new compressor would operate in a manner consistent with design parameters and performance goals when it returned to commercial operation.

A milestone in every validation program conducted by Siemens for its gas-turbine upgrades is a physical inspection of parts, with the first opportunity planned to inspect the compressor after approximately 4000 hours of service. Once again, the OEM invited participation of the steering committee, this time to witness the inspections and to see the service-run hardware.

The compressor cover was removed when the owner/operators arrived at Millennium. Under their watchful eyes, Siemens field and design engineers combed through the compressor. No measurable wear or issues with the new components were in evidence.

The excellent report card, coupled with the verification testing, convinced Millennium's owner, MACH Gen LLC, to move forward with the new compressor configuration at its New Harquahala Generating Co LLC. The Millennium test center was demobilized and the gas turbine with the new compressor was returned to commercial operation.

Final phase of the test program involved a unit inspection in September 2010 at about 9500 equivalent base-load hours of operation. Results were within Siemen's design expectations and the new compressor test program was concluded. Familiarity with the redesigned compressor undoubtedly convinced other owners to change out the compressors on their units: By yearend 2010, seven units had replaced their compressors with the new design.

The success of the collaborative development program is likely to usher in a new paradigm in problem-solving: OEM and customers working together on issue resolution for mutual benefit. For the W501G units, which all have long-term service agreements with Siemens, this certainly seems to make good sense.

G-class HRSGs

Most gas-turbine user groups were formed by owner/operators to create an open forum on issues specific to a given engine model. The benefits included faster problem resolution, avoid mistakes made by others, facilitate collaboration with the OEM, etc. In the early years of these volunteer organizations, virtually all discussion focused on the engine.

As GT punch-list items were resolved, program content for annual meetings expanded to address other plant issues, which oftentimes were major contributors to unit unavailability. Presentations on generators, steam turbines, HRSGs, high-energy piping systems, and plant control systems were added to the collective discussion.

With the oldest W501G-powered combined cycles at a nominal 10 years of age, the wear and tear of cycling service was beginning to show on the fleet's HRSGs, which had been designed for base-load service. The steering committee invited Nooter/Eriksen to update the group on boiler issues and modifications owner/operators might consider to help assure top reliability/performance over the long term.

Joe Schroeder, senior VP engineering, and Paul Gremaud opened their 90-min presentation with a review of N/E's experience. The company's HRSGs sit behind two-thirds of the W501Gs and 42% of the W501Fs in combined-cycle service. The comprehensive review of HRSG issues encompassed more than five-dozen slides.

Duct-liner damage was the first subject addressed (Fig 3). It is found in a large percentage of the transition ducts connecting GTs to HRSGs made by virtually all manufacturers—particularly where generating units designed for base-load service have been cycled extensively.

Solutions offered by N/E included addition of (1) stiffeners on the casing sidewall and/or floor, (2) intermediate liner pins, and (3) extra batten channels and backup angles to stiffen the liner. An increase in the thickness of the liner plate also should be considered.

Much has been written on this subject, and other deterioration mechanisms as well, in the COMBINED CYCLE Journal and elsewhere. Two examples:

- Access www.combinedcyclejournal.com/archives.html, click 3Q/2008, click "Orlando CoGen" on the issue cover; also "Learn the basics of HRSG inspection."
- *HRSG Users Handbook.* If a copy is not available at your plant, order online at www.hrsgusers.org.

Meetings of the HRSG User's Group are another good information resource. Its conference programs dig down into problem areas if you're looking for detail. Next meeting is in April (see ad, p 79).

The inlet-duct distribution grid, like the duct liner, is an uncooled component that "sees" GT exhaust temperature. It is used in supplementary-fired units to assure proper flow distribution in the HRSG. The stiffened flat plate generally is made from a 300-series stainless steel and has from 40% to 60% open area.

Problems typically include grid deformation and weld failures caused in large part by working of the material from expansion/contraction during startup/shutdown and from vibration associated with the high gas flows and turbulence (Fig 4). Modifications to minimize the probability of grid issues include (1) addition of or modification to the floor restraint system and to sidewall restraints, (2) addition of a gusset at the sidewall restraint plate, and (3) the addition of stiffener bars on the grid fabric.

3. Duct-liner damage is relatively common in HRSGs required to cycle daily

4. Inlet-duct distribution grids, like duct liners, typically take a considerable beating in cycling service

Removal of condensate during startup, operation, and shutdown was the next topic and one that generates considerable discussion at every HRSG User Group meeting. Gremaud called to the group's attention the 2006 addenda to Section I of the 2004 edition of the *ASME Boiler and Pressure Vessel Code* which assure better reheater and HP superheater condensate management.

The addenda include Part PHRSG, "Requirements for heat-recovery steam generators," which contains mandatory requirements for both desuperheater drain pots and reheater and superheater drain systems. Gremaud stressed, "If condensate is not removed, bad things happen."

N/E explained to attendees how condensate issues materialize and how to prevent them. It also showed its solution for preventing water accumulation during desuperheater operation, which meets the requirements of Part PHRSG. Plus, Schroeder explained N/E's reheater bypass system, which eliminates the need for a desuperheater while improving reliability and efficiency (energy in steam is not quenched with water).

To get a better idea of what happens when condensate is not removed quickly, access www.combinedcyclejournal.com/archives.html, click

Fall 2004, click "Avoid desuperheater problems" on cover. For more on desuperheater best practices, click 3Q/2006, click "Monitoring and maintaining desuperheaters." The subject also is discussed in depth in the *HRSG Users Handbook*.

Additional improvements to accommodate cycling offered by the N/E team included welding of tube stubs to headers in the shop, spring-supported tube coils, internal coil flexibility, and more forgiving piping layouts. Regarding tube stub-to-header welds, careful consideration should be given to the type of joint selected (access CCJ archives, click Summer 2004, click "Review basics of tube-to-header joints"). The optimal joint for a cycling unit is one that minimizes header wall thickness.

Welding tube stubs to headers in the shop offers a controlled environment conducive to better joints and simplifies the nondestructive examination critical for assuring quality welds. Spring support of headers and internal coil flexibility allow heat-transfer sections to move freely and reduce by orders of magnitude stresses that otherwise would be experienced.

Investigation of tube leaks was another important segment of the presentation. It offered O&M personnel a valuable checklist for gathering information and for evaluating that information. Critical to every tube-failure investigation is a map of the HRSG that pinpoints each failure location, Schroeder and Gremaud told the group. When you find a leak, they recommended inspecting adjacent tubes, checking for tube buckling, and taking plenty of pictures. One of your goals is to work towards a root-cause evaluation. Can you ID pitting, corrosion, swelling, or blistering?

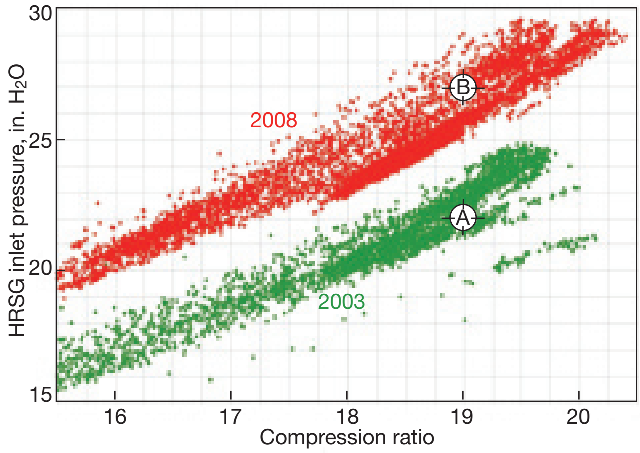
Other questions you should ask yourself, include the following:

- What component has the problem? What doesn't?
- What is wrong? What could be wrong and isn't?
- Where is the problem? Where else could the problem be but isn't?
- When did the problem first occur? When could the problem have been observed but wasn't?
- Any trend or pattern? If the problem has not been noticed since the first occurrence, why not?

Don't forget to extract failure samples where appropriate. Samples are very important. Before removal, mark the sample top, bottom, orientation, tube number, etc. Mechanically remove the sample; burning can destroy it. Protect sample surfaces. Keep in mind that if you don't determine the cause of a failure, you are likely to experience it, or something similar to it, in the future.

How to minimize back-end fouling was the last segment of the presentation. Solutions discussed included improved design of the ammonia injection grid, better AIG tuning, improved control of ammonia injection, additional catalyst to minimize slip, and delay ammonia feed during unit startup.

The N/E presenters pointed to sulfur as a culprit in many back-end fouling situations. The plant owner/operator should be vigilant in limiting fuel sulfur content, they told the group. One suggestion was to limit mercaptan addition for gas-leak detection, or to eliminate it altogether by switching to an odorant that contains no sulfur.



5. Historic data show a nominal increase in HRSG inlet pressure of 5 in. H_2O (point A to point B) over a five-year period because of fouling

Methods for removing ammonia salts deposited on heat-transfer surfaces in the cooler sections of the HRSG included both traditional methods—dry-ice blasting, high-volume water flush, and high-pressure air—and nontraditional methods—such as coil vibration, sonic vibration, steam cleaning, sootblowers, heating of coils, etc.

Millennium LP economizer mod

Managing an unregulated electric generating plant is not for the faint of heart. Meeting the budgeted income target generally is top priority, as it is for most free-market enterprises, making everything that influences income a priority—which is just about *everything*.

In such a demanding environment, knotty problems can be particularly wearing on the management team. A small onsite O&M staff, generally limited engineering capability at headquarters, parsimonious budget, and days only 24 hours long mean possible solutions may require a long-term team effort before they can be thoroughly researched and presented for budgetary approval. The gestation period may be years.

Fouling of the Millennium HRSG illustrates the point well. Steve Snopkowski, O&M manager, explained to the group that because of accelerated tube-side fouling, HRSG backpressure had progressed to the point where the unit could not achieve its base-load rating at ambient temperatures in the low 30s. Left unchecked, fouling would cause operating restrictions at temperatures as high as 40F. Not a concern in Florida, perhaps, but Millennium is in Massachusetts. He summarized the plant's concerns with the following bullet points:

- Derates were as much as 50 MW below the declared capability.
- Operating limitations were imposed because of high HRSG backpressure and high pressure at the steam turbine HP inlet.
- Backpressure was increasing over time.
- If fouling were not addressed, the frequency of derates, and capability lost, would continue to increase.
- Plant value would be negatively impacted by declining production.

Plant Manager Mark Winne, who started at Millennium during plant construction, said that back in the 1996-1997 timeframe a decision was made to "design-in" HRSG performance goals. Nooter/Eriksen proposed a HRSG with tight tube spacing both to achieve desired thermal performance and to accommodate an economic footprint. Westinghouse Power Generation, which had project responsibility, accepted the design.

Winne said that the tube rows in the LP economizer are so close to each other that the fins on tubes in adjacent rows almost touch. Also, there is relatively little space between fins. He mentioned that, based on a Millennium staff evaluation, locating so much heat-transfer surface in such a small space offered little in terms of performance gain. In fact, Winne continued, after only about 1000 hours of operation, fouling, exacerbated by the tight spacing, had negated the efficiency improvement designers intended to provide.

Aggressive heat-transfer design was only part of the problem. The unit, built for base-load service, was cycling and often dispatched at less than rated output. The resulting "cool" back-end gas temperature increased the potential for fouling of LP heat-transfer sections.

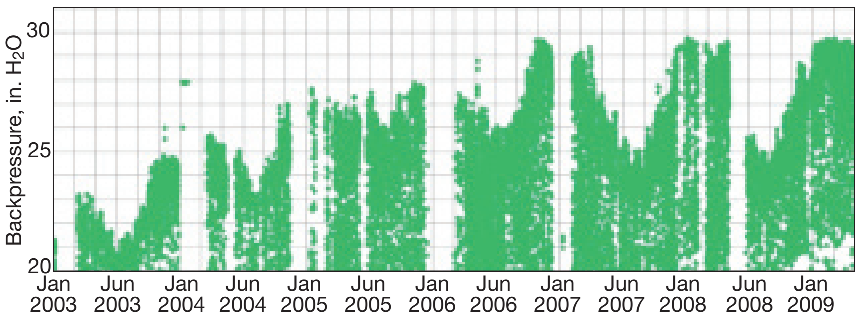
Also, as part of the original design of the emissions control system, the HRSG has a CO catalyst bed upstream of the SCR. While the first catalyst bed provides environmental benefits by converting CO to CO_2, it also is effective in converting SO_2 to SO_3. At the acid dewpoint temperature, SO_3 wreaks havoc by combining both with unreacted ammonia from the SCR and moisture to produce ammonia bisulfate, a cementitious foulant.

Millennium's rigorous performance monitoring program revealed increased backpressure and bothersome heat-rate degradation in the first couple of years of service. Winne recalled attempts at tube cleaning in 2003-2004 using CO_2 and compressed air. While generally effective in improving heat-transfer characteristics, tube cleaning was not successful in restoring the backpressure to original conditions.

Each year the backpressure crept a little higher, such that Snopkowski had to work with Nooter/Eriksen to design and install additional stiffeners and reinforcement to increase the HRSG's backpressure rating to 30 in. H_2O from the original 25 in. By 2007, the increasing backpressure trends caused plant personnel to believe that conventional HRSG cleaning techniques might never achieve the plant's performance goals.

Snopkowski illustrated that point early in his presentation, which he prepared in collaboration with Bill Lovejoy and Joe Michienzi. Hourly average data for 2003 and 2008, compared in Fig 5, show that over a period of five years, fouling added about 5 in. H_2O to HRSG backpressure. Note that Lovejoy works out of the NAES Corp regional engineering office in New England; Michienzi is an engineer with Competitive Power Ventures Inc, which provides asset management services to Millennium and its owner MACH Gen.

The O&M manager explained that compressor ratio (horizontal axis) provides a good indication of gas-side mass flow. The basic premise, he said, is that HRSG components in the gas path are flow restrictions and the change in pressure (vertical axis) over time indicates the increasing restriction caused by fouling of those components. No surprise, Snopkowski added; there's plenty of visual evidence inside the HRSG.



6. HRSG backpressure over time illustrates seasonal variations—valleys in summer, peaks in winter. Boiler limit is 30 in. H_2O, forcing operators to manually limit gas flow through the HRSG on occasion by changing position of compressor inlet guide vanes

He commented on the outliers in the 2003 data, saying the green points at the lower right of the graph were for data taken before addition of a second half layer of SCR catalyst (for additional NO_x reduction capability), which alone contributed about 3 in. H_2O to backpressure. The mass of red at the bottom of the 2008 data reflects a "clean" HRSG; the upper band, a dirty boiler. The chart allowed Snopkowski and his colleagues to develop a correction to HRSG backpressure to normalize the reading to a fixed compressor ratio/implied flow.

Fig 6 illustrates the seasonal variations in backpressure—peaks in winter, valleys in summer. Operators maintain pressure drop below the maximum allowable 30 in. H_2O by manually limiting flow through the HRSG using the compressor inlet guide vanes.

Snopkowski and colleagues applied their correction and normalized the backpressure to a compression ratio of 20 or about 30F to remove the effects of seasonal variations. This view of the data showed that periodic cleaning of the tube bundles and catalyst—particularly the latter—had a positive impact on performance. However, the new compressor discussed in the first section of this report (refer back to Fig 1) increased mass flow through the HRSG (by restoring the compressor to its new and clean condition) and, therefore, backpressure.

Next goal was to chart the pressure drop through the unit, from the reheater inlet to stack outlet, to see what section was having largest adverse impact on performance. Investigators found that the pressure drop through the LP economizer, with its significant buildup of ammonium bisulfate, was 10 in. H_2O. Thus, a heat-transfer section with only 11 of the HRSG's 78 rows of tubes accounted for close to half the pressure drop.

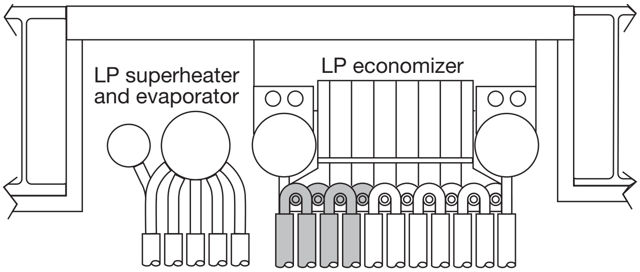
What to do? Winne and the Millennium team, together with Lovejoy and his colleague Jim Koch, an independent plant performance consultant based in Hilltown, Pa, believed a few rows of economizer tubes could be removed to reduce pressure drop and create a lane to facilitate cleaning of the remaining tube rows in the LP section with minimal impact on heat rate. There was no precedent for such a solution that anyone could recall.

Numbers generated by Lovejoy and Koch suggested that by removing four rows of tubes, backpressure would decrease about 3.7 in. H_2O and there would be a commensurate increase in plant output (Fig 7). The penalty associated with doing this was virtually negligible: An increase in heat rate of less than 10 Btu/kWh, assuming the worst case of no thermal benefit from improved cleaning.

Nooter/Eriksen engineers reviewed the manufacturer's design for the Millennium HRSG and re-engineered the unit with the first four rows of LP economizer tubes removed. Their numbers jibed with calculations made by Lovejoy and Koch, giving plant staff greater confidence in the solution proposed.

The cost estimate to alleviate the plant's winter constraint on power production was close to the expected annual revenue benefit from making the modification and the project was funded.

Field work required to implement the modification was challenging because of a tight schedule requirement—nine days from start to finish. There were three bidders,



7. Four rows of LP economizer tubes were removed (color), reducing backpressure by 3.7 in. H_2O

8. Tube rows were removed (left) by cutting tubes in nominal 10-ft segments and lowering them one by one to the floor. Each segment weighed just under 100 lb (with foulant)

9. Tube segments await removal through stack door (right)

10. Jumper pipes connect header to fifth row of tubes after removal of the first four rows

with Bremco Inc, from nearby Newport, NH, prevailing.

Its project manager, Bob Morse, recalled the job's first challenge: No opportunity for an internal inspection prior to project start. All planning and estimating was done by Morse, Lead Welder Gary Martin, and Estimating Manager Dick Grace based on boiler drawings and information supplied by Millennium and gathered during an external walk-down. Morse told the editors that critical to Bremco's decision to bid to the demanding schedule was the company's ability to provide jumpers requiring half the number of field welds estimated by plant personnel.

When the Bremco team gained access to the LP economizer section on the first day of the project, Morse recognized that the severe fouling would make the job more difficult than anticipated. It was tough to find tube ties, drains, etc, he remembered.

First step was to cut off the lower headers by torch and drag them outside through the stack door. Next, workers cut across all four rows of tubes near the tube ties located about 10.5 ft above the headers just removed. The opening created was less than 2 ft across (Fig 8). Note that the Millennium HRSG is three panels wide with 20 tubes per panel. That adds up to 240 tubes in the four rows, each more than 60 ft high. Perspective: Laid end to end the tubes would extend nearly three miles.

As each nominal 10.5-ft tube section was cut free, it was lowered to the boiler floor manually, using appropriate rigging (Fig 9). Each segment weighed nearly 100 lb, tube plus deposits. After the lower 10.5-ft section was removed from each of the tubes, work began at the first tube-tie level. The next section of tube extended from one tube-tie elevation to the next. Planking was placed on the tube ties to form a platform for workers as they cut into the tube rows.

Header connection. The Bremco team cut off the top section of each tube in the first row with a torch, leaving a stub of about 2 in. still welded into the header. Those stubs were trimmed off with a saw and then prepped for welding. Leaving an adequate stub eliminated the need to weld on the header, which would have required stress relief to comply with the *ASME Boiler & Pressure Vessel Code*.

Fig 10 shows that installation of the new jumpers from the headers to tubes in the fifth row of the LP economizer required removal of fins from the top 6 in. of those tubes to allow for prep work and welding. Bremco used an Esco Tool (Holliston, Mass) definner for this operation and an Esco external-clamping Warthog to make the 120 weld preps.

The jumpers were made by Potts Welding and Boiler Repair Co, Newark, Del. Before Bremco arrived at Millennium, Potts had done half the work involved in jumper preparation. Specifically, it made one of the 90-deg bends shown in Fig 10 and left the remainder of the pipe segment straight.

As Bremco personnel called Potts with exact field measurements for each jumper, the second bend was made and the jumpers were shipped overnight to the site. The jumpers were welded to the tubes first, to minimize the number of mirror welds. The jumper-to-header (tube stub) welds completed installation.

Note that quality control is critical to the success of projects such Millennium's, both for the owner (schedule did not allow time for rework) and for the contractor (rework reduces profit). Bremco's qualified inspectors verified fit-up before each weld was started, checked each root pass visually, and relied on dye penetrant to verify integrity of the cap welds. The requisite hydro revealed no leaks.

Summing up, Winne said that all-in-all the project was viewed as very successful by owner MACH Gen. It is performing as well or better than planned; and the improved access for cleaning should allow adequate cleaning to arrest the steadily increasing backpressure that forced the Millennium team into action. The success of the project has caught the attention of several other 501G Users who are wrestling with similar backpressure issues. CCJ

Compressor, turbine share the spotlight

2011 Annual Meeting

February 14-18
Paradise Point Resort & Spa
San Diego, Calif

501F steering committee

Chairman: Russ Snyder, plant manager, Cleco Power LLC

Vice Chairman: Ray Martens, plant manager, Iberdrola Renewables Inc

Paul Tegen, chief CT/I&C engineer, Cogentrix Energy Inc

Ivan Kush, director of outage services (Siemens fleet), Calpine Corp

Martha Leskinen, senior engineer, SRP

Paul Terry, rotating equipment reliability engineer, PPG Industries Inc

Rene Villafuerte, plant manager, Comego SA de CV

There was a presentation or discussion of value in every time slot at the 2010 conference of the 501F Users Group, and not all were about the gas turbine. The change of pace provided by switching among several other topics of importance to attendees—including safety, electric generators, steam turbines, and plant management—helped maintain interest at a high level throughout the four-day meeting.

Two optional sessions kicked-off the conference mid morning of Day One, giving attendees traveling on Monday time to register, get settled, and ease into the intense technical program. Both sessions—one on generators, one on gas-turbine mods and upgrades—were presented by experts from Siemens Energy Inc, Orlando.

The generator thread carried over into the afternoon with National Electric Coil's Howard Moudy, director of service management, holding the attention of an SRO audience with a high-powered presentation on spark erosion and partial discharge.

Moudy moves so quickly through his material that taking meaningful notes is virtually impossible. So the editors asked NEC to share the content of that 501F presentation with all generator users by preparing an article on spark erosion and partial discharge for the upcoming 2011 Outage Handbook; you'll be receiving that soon. A users-only breakout session on generators, chaired by Paul Terry, a member of the steering committee (sidebar), wrapped up the afternoon.

One of the best ways to keep up on generator technology and O&M between user-group meetings is to join, at no cost, the *International Generator Technical Community* online forum at www.generatortechnicalforum.org (ad, p 136). The site features 13 problem-solving forums and a rapidly expanding technical reference library. There were more than 550 registered members of the "generator community" by yearend 2010.

Compliance issues and solutions associated with the NERC Critical Infrastructure Protection (CIP) standards (cyber security) are straining the limited management resources at many plants today. The steering committee invited Dr Matthew E Luallen to address the timely subject and then followed up with a user-only breakout moderated by Russ Snyder, chairman of the 501F steering committee. The CIP track ran in parallel to the generator track, allowing attendees a choice of subject matter.

Day Two was all users, all the time, with dozen or more presentations and follow-on discussion roundtables. Siemens Day was Wednesday and included detailed coverage of issues in the compressor, combustion, turbine, and exhaust sections.

The morning of Day Four was dominated by user discussion early and closed out with a presentation by Chip Thompson and Jason Yost of Mercer Thompson LLC on the changing nature of long-term service agreements. This information also is of interest to owner/operators outside the 501F family has been compiled into an article for the Outage Handbook. Thursday afternoon was dedicated to steam turbines.

This report presents the highlights of a few user presentations and discussions conducted over the four-day meeting. To dig deeper, locate the user presentations on the 501F User Group's website, which can be accessed through www.users-groups.com by registered members. If you qualify for membership in the organization but have not yet joined, this also can be accomplished on the website. Siemens presentations are accessible by owner/operators of the OEM's frames who apply for and are registered to access the manufacturer's Customer Extranet Portal.

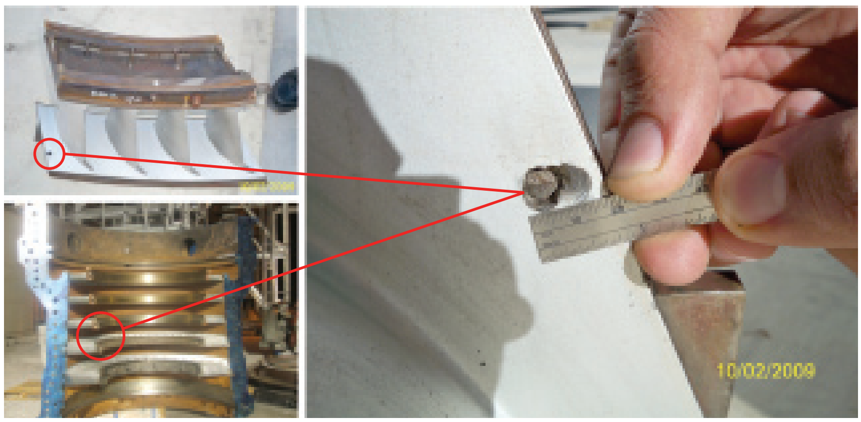
Safety discussion. The first full day of presentations (Day Two) began with an open forum on safety concerns, practices, etc, with Steering Committee Vice Chair Ray Martens as the moderator. The half-hour session opened with discussion on safety procedures for the handling and storage of ammonia for NO_x control, fall protection for gas-turbine maintenance, management-of-change procedures, and drawing maintenance.

Scaffolding was a subject the group wanted to talk about. This thread covered training, inspection, procedures, etc. One user said that at his facility one plant employee is assigned the task of inspecting scaffolding daily. No one is allowed to change scaffolding except plant personnel tracking such changes or the contractor running the job. The recommended penalty for anyone violating this policy: Immediate dismissal.

Confined-space welding got air time as well, with the combustion section a target area. Suggestion was to do everything possible to eliminate the restrictions that require the combustion section to be classified as a confined space. By so doing, you avoid rescue-team constraints.

A question on the proper clothing for working on energized components was asked. One concern was related to cost: Do you buy or lease? A user who thought buying protective clothing was the way to go because of the high cost associated with leasing suggested to the others that they seriously consider leasing.

His experience: The purchased clothing was not holding up well, even with no abuse. He also pointed out that if you own the gear, you're responsible for cleaning and fixing it; plus, new



1. Plug weld liberated from an R2 strongback diaphragm and traveled downstream in the compressor, damaging many blades in the process

hires might not fit in the clothing you have available. The lessor assumes responsibility for providing clothing to fit the employees you have, for cleaning, and for any repairs.

What about fatigue considerations during a long outage? Fatigue is known to compromise safety. One school of thought was that no one should work more than six days a week, another said workers could get by with one day off every two weeks.

Martens assumed the role of speaker when the open discussion period ended. The subject was his plant's experience in implementing a cornucopia of best-in-class performance upgrades from Siemens, each of which had satisfied the OEM's rigorous commercial test criteria but collectively had never been installed on one engine.

Martens is plant manager of Klamath (Ore) Cogeneration, a 2 × 1 501FD2-powered combined cycle. Owner Iberdrola Renewables wanted the ultimate in flexibility at Klamath: A base-load unit capable of daily cycling. Here's a summary of what the plant achieved with the upgrades:

- Increase in generating capability of up to 6% at base load.
- Improvement in base-load heat rate of up to 2%.

- Better part-load heat rate.
- Turndown to 50% of rated capacity without exceeding 10 ppm CO (when ambient temperature is between 59F and 95F.
- Opportunity to reduce total emissions during engine startup.
- Increased SCR efficiency at low load.
- Extended intervals between overhauls.

For details on the Klamath upgrade, access www.ccj-online.com/archives.html, click 3Q/2009, click "Klamath gets better with age" on the cover.

Strongback diaphragm. The first of nine relatively brief (typically 15-20 minutes each) "issues presentations" glued the eyes of virtually all attendees to the screen. This is considered by many owner/operators as the most important part of the meeting. The idea is to share experiences and solutions to avoid a repeat incident; it's what user groups are all about.

The owner presenting said a rapid downward slide in compressor performance reduced power output of one 501FD2 by about 10 MW over a period of about 10 days. Initial prognosis was carryover caused by an inlet evap-cooler issue. Unit was removed from service to correct the problem.

Personnel discovered a plug weld missing from a R2 strongback diaphragm with 13,000 service hours (Fig 1). The liberated weld traveled down the compressor, damaging many blades in the process. Damage was consistent with the size and shape of the plug. R1, R2, and R3 all were affected and all were replaced. Several blades also were replaced in stages further back in the machine.

The speaker noted that the OEM was still investigating the event, which is not believed related to the carryover issue. Siemens was said to be reviewing the design and use of restraint pins introduced to constrain the motion of the inner shroud at the ends of the strongback segments.

Its compressor designers added to the collective knowledge on this issue during Siemens Day.

The problem reportedly had not been associated with any other machine in the fleet at the time of the presentation. The bottom line: Only R1 blades were impacted by evap-cooler carryover; most of the performance loss was attributed to damage caused by pin-balling of the plug weld, which was never found.

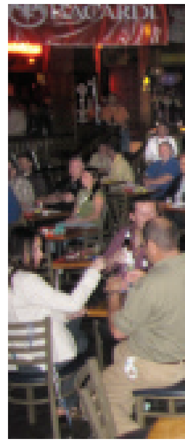
R2 ring-segment side-seal liberation. A borescope inspection scheduled for one of the two 501FD2s at the next presenter's plant revealed extensive damage. The machine was operating normally with no significant indications other than those exhibited on one of the combustor cans. Investigation revealed a broken UV detector tube and FOD on R3 blades (Fig 2).

2. Part of a UV detector tube liberated, traveled downstream, and damaged R3 blades and other components

3. Side seal "walks out" from between adjacent ring segments

Parts of side seals liberated from R2 ring segments were found while looking for missing portions of the detector tube that went downstream (Fig 3). The presenter said the same phenomenon—often referred to as seal "walk-out"—had been experi-

501F, G users come together for vendor fair, other activities



The 501F and 501G Users Groups co-located for the fourth consecutive year in 2010. The partnership works well and is a win/win/win for the users, third-party equipment and services providers, and Siemens Energy Inc, Orlando, the OEM for both engines. Technical user-only sessions are combined or separate depending on the subject matter; members of both groups come together for meals, social events, and the vendor fair.

Luncheon presentation. Tim te.Riele, PSM's (Jupiter, Fla) VP R&D engineering, and Mark Bissonnette, the company's VP commercial operations, gave 501F owner/operators several reasons to consider the third-party supplier a viable alternative to the OEM for new hot-gas-path parts, repair of existing components, outage management activities, and long-term service agreements.

te.Riele reviewed PSM's products and services for the 501FD, illustrating the company's success using photos taken during a recent HGP inspection that showed parts in excellent condition after 25,000 fired hours. First-stage turbine blades were removed for refurbishment, while the second- and third-stage blades were reinstalled.

Transition pieces were the next topic. te.Riele told his luncheon audience that PSM's design had been fully validated and stressed its operational flexibility and favorable life-cycle cost. He reported that more than 40 sets of PSM TPs were installed in the 501F fleet (65 sets by the end of 2010), a significant percentage of the nominal 230 gas turbines in operation. Stated maintenance interval for the TPs is 24,000 hours/900 equivalent starts; expected life is 72,000 hours/900 ES.

The R&D executive also reviewed his company's experience with an extended-interval combustion liner in commercial service and its automatic, continuous combustion tuning product, which is designed to eliminate manual seasonal tuning.

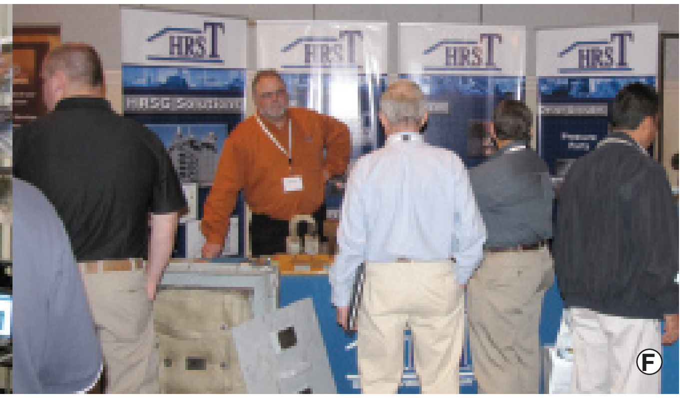
A review of the company's Jupiter facilities closed out te.Riele's portion of the presentation. He discussed the F-class reconditioning facility opened in spring 2009 and now in full commercial operation. It is capable of performing all refurbishment processes onsite, including: chemical stripping, brazing, laser tip welding, EDM hole drilling, and HVOF/APS and DVC coatings. The one-stop shop was said to offer advantages in quality control and in repair cycle time.

enced previously on R1 ring segments and on ring segments "right out of the box."

A root cause investigation was ongoing at the time of the presentation. R2 rubbing did not appear to be a factor and no obvious problems could be traced to the installation of the ring segments themselves. Visual inspection revealed poor quality of some welds holding seals in place and inconsistent staking of the seals on others. Six ring segments were submitted for metallurgical analysis: two had seals missing, two had cracked welds, and two had seals intact.

Corrective action: The plant purchased a set of new R2 ring segments from a third-party manufacturer and had them installed. The entire R3 vane and blade rows were replaced as well. Downstream deflection of the R3 vanes plus several damaged airfoils suggested that row replacement was the prudent decision. At least 15 R3 blades had to be scrapped. Eight R4 blades also were scrapped, other R4 blades blended, and the row resequenced for installation.

R1 turbine disk cracking was covered in two user presentations. Cracks were identified on one machine at each blade location. They were found during a rotor inspection after approximately 5000 equivalent starts and 47,500 equivalent baseload hours (Fig 4). The unit had been cycling daily and performing load-



Rotor repair is the next step for PSM, te.Riele added, stepping back from the podium. That work would be conducted at parent Alstom's Richmond rotor facility using parts designed and manufactured by PSM.

Bissonnette touted the extensive capabilities of the company's extended service offerings, which rely in large measure upon Alstom's expertise in steam turbine and generator overhauls. He also reviewed PSM's long-term service agreement offerings, touching on the flexibility of terms and customized risk coverage.

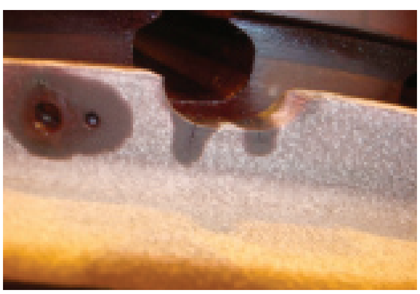
Social networking. You can't meet someone half a room away during a discussion session. You might meet someone waiting for coffee during a break—if it's a slow line. More than likely, however, the best opportunity for extending your network is at a social function or the vendor fair.

The 501F and 501G users always have first-class social events. The kick-off functions at the Disney Yacht & Beach Resort were two welcome receptions, one in the marina area hosted by Millennium Power Services, Rochem Technical Services, and IAFD-Industrial Air Flow Dynamics; the other in the pool area sponsored by GTE-Gas Turbine Efficiency (Fig A).

Mitsubishi Power Systems Americas sponsored a Fat Tuesday Mardi Gras reception and dinner (Fig B), while Siemens provided entertainment and dinner on Wednesday (Fig C).

The vendor fair and Monday reception was well attended by both vendors and users. A packed ballroom testified to the event's success. Perhaps as many as one-third of the participating vendors did not offer gas-turbine parts or services, enabling plant personnel to broaden their professional horizons.

To illustrate: Bremco Inc brought users up to date on HRSG pressure-parts mods (Fig D), such as those performed at Millennium and featured in a 501G case history (p 151); KE-Burgmann USA displayed its repair methods for dealing with exhaust manifold cracking (Fig E; for details, access www.ccj-online.com/archives.html, click 2Q/2008, click 501F Users Group on cover, scroll to p 18); HRST Inc focused on its HRSG inspection and aftermarket solutions (Fig F); and Cutsforth Inc was explaining the value proposition for its EASY-change brush holder system (Fig G; for details, access ccj-online once again, click 3Q/2009, click 7F Users Group, scroll to p 26).



4. R1 turbine disk cracks were found at each blade location

5. Blend repair reflects OEM's recommended procedures

following duty.

Siemens suggested (1) light blending of all indications to remove the minimum material to assess crack depth; (2) blending in steps to assure cracks are eliminated with a minimum of metal being removed; and (3) using generous radaii during the blending operation; no sharp corners or edges (Fig 5). Magnetic particle testing was recommended to assure cracks are removed. Documentation supported by photos was urged. CCJ

NV Energy dedicates combined cycle for the renewables era

NV Energy dedicated its Goodsprings Energy Recovery Station in mid November (Fig 1). Ordinarily, a 7.5-MW generating plant would not be headline news, but this project is special, featuring both a Brayton/Organic Rankine (ORC) combined cycle and dry cooling.

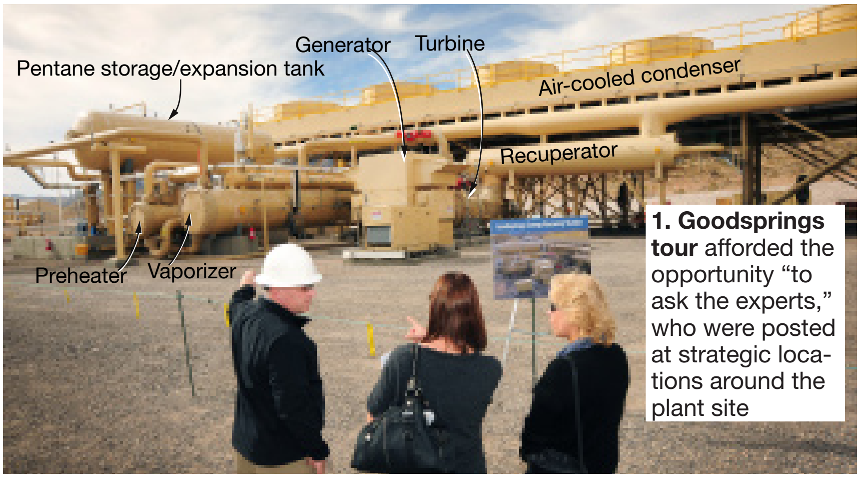
Located 35 miles south of Las Vegas, Goodsprings is southern Nevada's first non-solar renewable energy project and also the first renewable energy project owned by state's largest utility. In sum, NV Energy has 44 separate geothermal, solar, biomass, small hydro, wind, and waste-heat recovery projects under contract that are either in commercial operation or under development. The company's renewable energy portfolio totals more than 1200 MW.

NV Energy is no stranger to combined cycles or to dry cooling. It owns and operates seven E- and F-class 2 × 1 combined cycles at five stations and has another in the final stages of construction. Air-cooled condensers (ACCs) serve four of the existing combined cycles and are installed at the new facility as well. Get details on the utility's generating plants at www.ccj-online.com/archives.html, click 2Q/2009.

Goodsprings differs from the company's conventional combined-cycle assets in several respects, including these:

- The gas turbines that provide thermal energy to the Rankine cycle drive compressors not electric generators; plus, they are owned by Kern River Gas Transmission Co, not NV Energy.
- Pentane, rather than water, is the working fluid at Goodsprings, making the ACC unique among the company's dry cooling systems.

The ORC technology was provided by Ormat Technologies Inc, Reno, which also manufactured key equipment and served as the EPC contractor. NV Energy President/CEO Michael Yackira pointed out to the more than 50 people attending the dedication that the plant's rated capacity was somewhat misleading. Intermittent renewable resources rarely achieve greater than about a 30% capacity factor, he said, but Goodsprings is expected to operate at a capacity factor of 90% or greater, making it equivalent to a solar or wind facility of 25 MW.



1. Goodsprings tour afforded the opportunity "to ask the experts," who were posted at strategic locations around the plant site

Kern River President Gary Hoogeveen told the group that his company is an advocate of increasing energy efficiency and of reducing greenhouse gas emissions. He added that if Goodsprings meets expectations, Kern River would likely invest in other heat-recovery projects along its 1680-mi pipeline, which runs from southwestern Wyoming to Southern California.

Chromalloy's new casting center for turbine blades, vanes fully operational

Chromalloy's 115,000-ft^2 state-of-the-art Tampa investment casting center was dedicated in early December at a grand-opening event hosted by President Armand F Lauzon Jr for engine manufacturers and operators from around the world.

The executive told the editors, "Chromalloy is pleased to now offer the industry a single source for engine component design, engineering, tooling, machining, repairs, coatings, and castings."

Use of a single-source provider for production of new and replacement parts, he continued, will help OEMs and operators reduce both cost and delivery time. To illustrate: The lead time for castings has been reduced to less than four weeks from the 12 to 16 required by the old Tampa casting facility, which has been decommissioned. Chromalloy operates a second casting center for turbine components and parts in Carson City, Nev.

The $30-million new facility, managed by VP Thomas Trotter, is designed to pour up to 1-million lb/yr of nickel- and cobalt-based superalloys for turbine components and parts to serve the "entire range of jet aircraft engines, as well as industrial land and marine aeroderivative and frame machines."

Important to CCJ subscribers is that Chromalloy can now supply the largest and most complex turbine blades and vanes in power generation service.

The facility tour enabled the editors to get acquainted with a modern-day foundry and the investment casting process, which proceeds this way:

- Inject wax into a pattern that forms the individual modules of the mold assembly shown in Fig 2.
- Dip the wax mold assembly into a ceramic slurry to form the ceramic shell required for casting parts (Fig 3).
- De-wax and sinter the ceramic shell (Fig 4).
- Load shells into the vacuum induction melting furnace, where alloy is melted and poured into the shells to produce single-crystal, equiaxed crystal, or directionally solidified parts (Fig 5).
- Remove shell and detach parts from the assembly.
- Finish and inspect.

Note that each step requires specialists to assure the degree of quality control required to support the lean manufacturing processes and six-sigma goal. For example, there's a Wax Team, a Shell Team, a Casting Team, and a Phoenix Team for final inspection.

Next step for the company is to construct a 40,000-ft^2 addition to the Tampa facility to manufacture the critical ceramic cores used to cast superalloy turbine vanes and blades. Ceramic cores are used in the investment casting process to form the complex internal cooling passages needed to keep these hot parts from burning up during operation.

Pre-engineering for the core facility is complete. Construction will begin in 2011 with first production expected early in 2012.

Fig 2

Fig 3

Fig 4

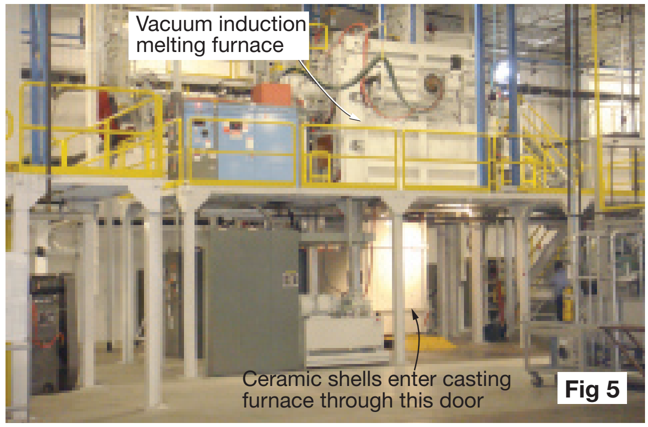


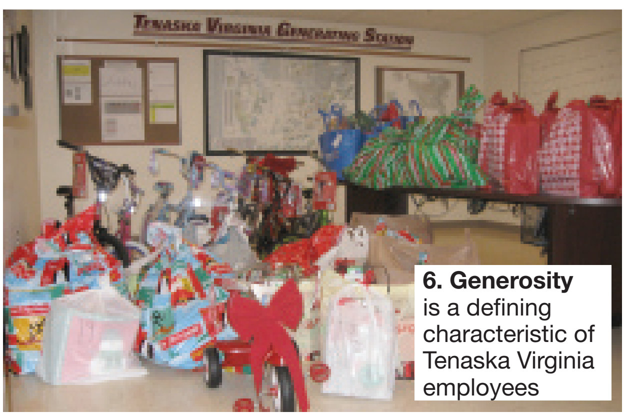
Fig 5

Santa Claus lives at Tenaska Virginia

Holiday generosity is a tradition at Tenaska Virginia Generating Station. Since the plant opened in 2004, the facility's 28 employees and their families have donated toys, clothing, blankets, sheets, etc, valued at more than $30,000 to needy people who have requested gifts through Fluvanna County Dept of Social Services (Fig 6).

Plant Manager Robert Mayfield told the editors, "We are pleased to be able to shine light into the lives of others. Many people forget about the less fortunate, developing a kind of 'tunnel vision' as they focus on the thrill of finding the 'perfect gift' for a loved one." The Tenaska Virginia staff never forgets the needy at Thanksgiving and Christmas.

Fluvanna Social Services thanked the plant employees for their continued support of the agency's "Adopt a Family Program." This year, Tenaska Virgina was the biggest sponsor of the county program.



6. Generosity is a defining characteristic of Tenaska Virginia employees

Company news

Vogt Power International Inc, Louisville, Ky, is selected by Siemens Energy Inc to supply heat-recovery steam generators for the conversion of Imperial Irrigation District's El Centro Power Plant (Unit 3) from a 44-MW conventional steam system to a 2 × 1 combined cycle. CO catalyst and SCRs will be incorporated into the dual-pressure HRSGs located behind SGT-800 gas turbines.

CH2M Hill, Englewood, Colo, achieves "substantial completion" of Empire Generating Co's 535-MW (base load; 635 MW peak power) 2 × 1 combined cycle located in Rensselear, NY, on a remediated brownfield site. Principal equipment: 7FA gas turbines and a D-11 reheat steam turbine from GE Energy, triple-pressure HRSGs from Alstom, 11-cell plume-abated/low-noise cooling tower from GEA Group.

Chromalloy reports having completed two LM2500 engine overhauls, three hot-section overhauls, and a wide array of LM2500 and LM6000 field-service events for industrial users since opening its new depot in San Diego in spring 2010.

NEM bv, Leiden, The Netherlands, a leading manufacturer of HRSGs with facilities worldwide, opens a full-service office in Greenville, SC. NEM USA offers new equipment and provides maintenance and engineering aftermarket and consulting services to North American power producers.

General Physics Corp, Elkridge, Md, announces that its Energy Services Group achieves "approved provider" status from the North American Electric Reliability Corp education program. This allows GP to deliver customized learning in support of NERC goals regarding continuing education for electric transmission system operators.

NAES Corp, Issaquah, Wash, unveils its new website at www.naes.com to provide more comprehensive and current information on the company and the services it provides.

Aviation, Power & Marine Inc, Boynton Beach, Fla, acquires the assets of Allied Power Group LLC's Capital Spares Div. The acquisition of hot-gas-path and consumable parts expands AP&M's capabilities into the frame gas-turbine market. In related news, Michael Elliott, joins AP&M as vice president. Elliott had been executive VP for Allied.

HRST Inc, Eden Prairie, Minn, announces the launch of its HRSG root-cause failure analysis program to permanently solve boiler issues faced by owner/operators.

ProEnergy Services, Sedalia, Mo, launches ProEnergy Controls Solutions, headed by Steve Huval, to design, integrate, install, and maintain control systems for gas- and steam-turbine/generators of virtually every make and model.

Swift Filters Inc, Oakwood Village, Ohio, announces that its quality management system has received ISO9001:2008 with design certification. Swift designs and manufactures filter and strainer elements for liquid and gaseous fluid systems. Filter elements are made of cellulose, microfiberglass, stainless-steel wire cloth, or stainless-steel felt media.

Pratt & Whitney Power Systems, East Hartford, Conn, announces that its new and repaired components for the GE 7FA+e gas-turbine line has passed the 1-million-hr mark of run-time service. The company accumulated the hours on more than 115 various sets of major hot-section components world-wide. For more information, access www.ccj-online.com/archives.html, click 2Q/2010, click Business Partners on issue cover.

Camfil Farr Power Systems, Stock-

7. IST executives receiving the Price Performance Value Leadership Award from Frost & Sullivan are Chris Ritchie, VP finance and administration; Michael Brady, VP EOR; and Bob Dautovich, president (l to r) holm, Sweden, announces its revamped website to facilitate communication with company experts and provide expanded information on products, services, and technologies.

Innovative Steam Technologies Inc (IST), Cambridge, Ont, Canada, receives Frost & Sullivan's 2010 North American award for HRSG Price Performance Value Leadership (Fig 7). Variables considered in the evaluation of IST against its primary competitors were: price, boiler features, ease of use, service support, and product matched to customer needs. The company had the top score in four of the five categories.

Siemens Energy Inc, Orlando, receives an order for two 1 × 1 SCC6-5000F Flex-Plant 10 power islands from NRG Energy Inc for installation in El Segundo, Calif. Each combined cycle will be capable of producing 300 MW 10 minutes after hitting the start button. Principal equipment: SGT6-5000F gas turbine, HRSG, SST-800 steam turbine, and air-cooled condenser.

Products/services update

Ludeca Inc, Doral, Fla, reports Rotalign Ultra's vibration acceptance check works in combination with Vibtool to measure vibration level according to ISO 10816-3. The RMS velocity value is transferred wirelessly and stored in the Rotalign Ultra computer, where the result

Fig 8

is instantly evaluated against the machine classification threshold. Vibtool can measure vibration severity, bearing condition, temperature, rotational speed, and pump cavitation (Fig 8).

Olympus NDT, Waltham, Mass, introduces 32.8-ft-long scopes for its lightweight IPLEX LX and LT industrial

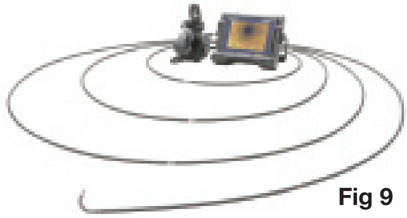


Fig 9

videoscopes to facilitate access to deep or difficult-to-reach areas. Design provides the stiffness to push deep into heat exchangers, boiler tubes, etc. Optics provide excellent magnification; LED lights illuminate subject to identify small defects (Fig 9).

ESCO Tool, Holliston, Mass, offers a full range of welding end-prep tools that combine a formed tool bit with an adjustable bit locking system to machine multi-angle end preps without cutting fluids. Millhog® comes in several models to handle tube and pipe from 2 in. ID to 32 in. OD with wall thicknesses up to 0.750 in. Chipbreaker tool bits direct heat away from the surface of the tool or pipe.

Prepzilla Millhog® ID-clamping end-prep tool can bevel any angle of prep and square the pipe ends on hard alloys in one step. Portable tool weighs only 40 lb and can work on pipe from 1.5 in. ID to 8.625 in. OD.

Fin removal tool lets operator rapidly remove up to 4 in. of fins from a tube OD in one step and in less than two minutes. The rigid ID-clamping tool has no reaction torque, requires no cutting fluids, and eliminates the need for chipping hammers, grinders, dirt, and dust. See Fig 10 in the 501G Users Group article starting on p 146.

Ebb tide

The generation sector of the electric power industry mourns the passing last December of two well-known generator solutions providers, Donald A Albright (84) and William da Silva (49).

Albright

Albright was well-respected among generator engineers. He joined General Electric Co's Large Steam Turbine Generator Dept in 1951, shortly after graduating from the Univ of Pittsburgh with a BSEE degree. There he developed and refined techniques for acquiring and analyzing air-gap flux probe data to identify shorted turns in generator rotors online and at speed and temperature.

After retiring, Albright founded Schenectady-based Generatortech Inc, which deals exclusively in the use of air-gap flux probes for assessing rotor shorted-turn conditions. In the last two decades, the company has provided air-gap flux probes for more than 4000 generators worldwide both working through OEMs and directly with end users.

Clyde Maughan of Maughan Generator Consultants, a frequent contributor to the COMBINED CYCLE Journal and a colleague of Albright's for six decades, told the editors, "Don was one of my all-time favorite work associates and, perhaps, more widely known than anyone I ever worked with. With his passing, the world has lost an outstanding engineer and a true gentleman."

da Silva, who established National Mechanical Services Inc, National City, Calif, seven years ago, was best known for his maintenance and repair skills on generators—specializing in units from about 25 to 125 MW. The editors were privileged to profile a couple of NMS's jobs and to benefit from da Silva's years of practical experience. His effervescence and firm handshakes will be missed at industry meetings.

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