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COMBINED CYCLE Journal


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INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

2013 User Group Meetings

March 18-21, 501F Users Group, Annual Meeting, Charlotte, NC, Westin Charlotte. Chairman: Russ Snyder, russ.snyder@cleco.com. Contact: Caren Genovese, meeting coordinator, carengenovese@charter.net.

March 18-21, 501G Users Group, Annual Meeting, Charlotte, NC, Westin Charlotte. Meeting is co-located with 501F Users Group; some joint functions, including the vendor fair. Chairman: Steve Bates, steven.bates@suezenergyna.com. Contact: Caren Genovese, meeting coordinator, carengenovese@charter.net.

April 7-11, CTOTF—Combustion Turbine Operations Technical Forum, Spring Turbine Forum & Trade Show, Myrtle Beach, SC. Contact: Wickey Elmo, group and conference coordinator, info@ctotf.com.

April 29-May 1, HRSG User's Group, 21st Annual Conference & Exhibition, Tampa, Fla, Tampa Marriott Waterside Hotel & Marina. Contact: Robert Swanekamp, executive director, info@hrsgusers.org.

May 20-24, 7F Users Group, Conference & Vendor Fair, Greenville, SC, Greenville Hyatt Regency. Contact: Sheila Vashi, 7F operations manager, sheila.vashi@7Fusers.org.

June 4-6 (team-building event June 3), 501D5-D5A Users, Annual Conference & Vendor Fair. Details as they become available at www.501d5-d5ausers.org. Contact: Gabe Fleck, chairman, gfleck@aeci.org.

June 17-20, Frame 6 Users Group, Annual Conference & Vendor Fair, League City, Tex (Houston area), South Shore Harbor Resort. Program details as they become available at www.Frame6UsersGroup.org. Contact: Wickey Elmo, conference coordinator, wickelmo@carolina.rr.com.

Week of June 24, V Users Group, Annual Conference, Williamsburg, Va. Venue not yet available. Contact: Dawn McCarter, conference coordinator, dawn.mccarter@siemens.com.

July 15-18, Southwest Chemistry Workshop, Tempe, Ariz, Tempe Mission Palms Resort & Convention Center. Host utility: Salt River Project. Contact: David Bollinger, Chemist/Environmental Scientist, Desert Basin Generating Station, dave.bollinger@srpnet.com.

July 21-25, Ovation Users' Group, 26th Annual Conference, Pittsburgh, Westin Convention Center Hotel. Register for membership (end users of Ovation and WDPF systems only) at www.ovationusers.com and follow website for details as they become available.

September 3-5, Combined Cycle Users Group, 2013 Conference and Discussion Forum, Phoenix, Ariz, Arizona Biltmore. Registration and program details at www.ccusers.org. Registration/sponsorship contact: Sheila Vashi, sv.eventmgt@gmail.com. Speaker/program contact: Dr Robert Mayfield, rmayfield@tenaska.com.

September 8-12, CTOTF—Combustion Turbine Operations Technical Forum, Fall Turbine Forum & Trade Show, Coeur d'Alene, Idaho, The Coeur d'Alene Hotel. Contact: Wickey Elmo, group and conference coordinator, info@ctotf.com.

October 13-16, ACC Users Group, Fifth Annual Conference, Summerlin, Nev, Red Rock Resort & Spa. Registration and program details at www.acc-usersgroup.org. Registration/sponsorship contact: Sheila Vashi, sv.eventmgt@gmail.com. Speaker/program contact: Dr Andrew Howell, chairman, andy.howell@xcelenergy.com.

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

December 3-5, Australasian HRSG Users Group, 2013 Annual Conference, Brisbane, Australia, Brisbane Convention Centre. Registration and program details as they become available at www.ahug.co.nz. Registration/exhibitor contact: Claire Warner, meetings@tmm.com.au. Speaker/program contact: Dr Barry Dooley, chairman, bdooley@structint.com.

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YF Young & Franklin Inc.

Founded in 1918 and headquartered in Liverpool, New York USA, Young & Franklin Inc. (Y&F) designs, manufactures and services turbine controls for the energy and oil & gas markets. Original equipment manufacturers and asset owners from across the globe look to Young & Franklin for fluid control solutions with the highest quality, reliability and maximum durability.

Y&F provides valves, actuators and controls to premier manufacturers of industrial turbines including General Electric Energy, Solar Turbines, Pratt & Whitney and GE Oil & Gas. With an installed base of products running on more than 10,000 industrial turbines, we have built a reputation based on technical expertise and product excellence.

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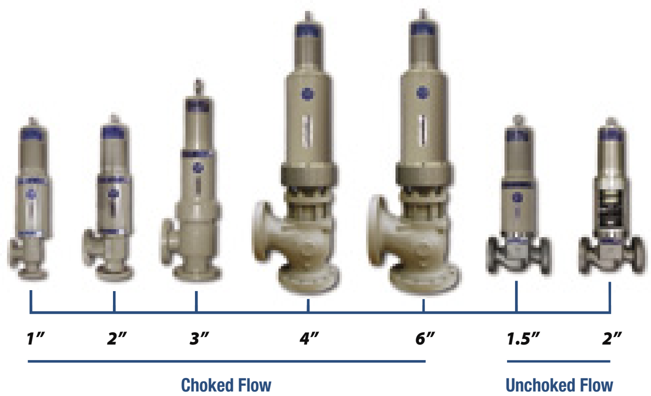

3010 Series EMA Gas Fuel Control Assemblies ~

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IGV Actuation Technologies

Isolation Valve *Isolation Valve in Double Block & Bleed Format*

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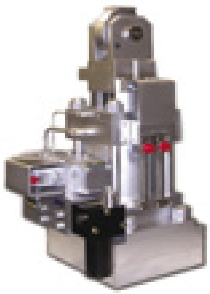
8641 Series Natural Gas Fuel Valve Assembly ~ A balanced double-poppet, all electric valve for gas turbine fuel/flow control. Operated by a Y&F 1100 Series Digital Motor Controller, the 8641 is a retrofit replacement for the Y&F 7-5078 Hydraulic Actuator/ Butterfly Valve and OEM Loader fuel control system on Solar Gas Turbines. The 8641 is designed for use on small turbines (1-20MW).

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



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

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It's Faster...

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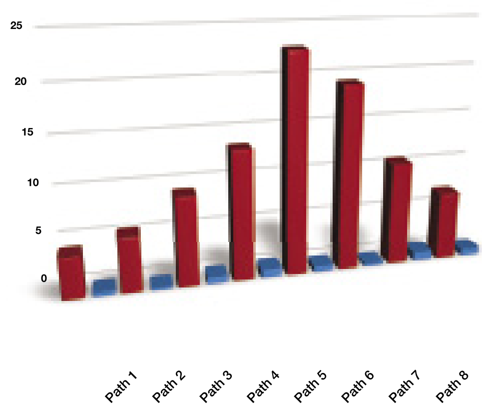
It Saves Money...

Your generators stay online avoiding lost revenue due to forced outages. Online Truing also greatly reduces flashover and ring fire risks, which are often caused by increased brush vibrations from out-of-round collector rings.

For more information about the benefits of our Online Truing Service and other Cutsforth products and services, contact us at ***800.290.6458 x29***

Example of Brush Path Vibration Readings
Before and After Online Truing - Detroit, Michigan



	Path 1	Path 2	Path 3	Path 4	Path 5	Path 6	Path 7	Path 8
Before	4.4	5.9	9.5	13.7	22.9	19.4	11	7.3
After	0.5	0.3	0.7	0.9	0.6	0.3	0.9	0.7

Measured in mils

"Cutsforth provided the high quality and individual detail that customers have learned to expect from a focused and dedicated subject matter expert. The close attention to detail resulted in our finding and repairing several other problems that could have been the root cause of past collector ring and brush problems."

T.P. - Principal Engineer, large East Coast power company

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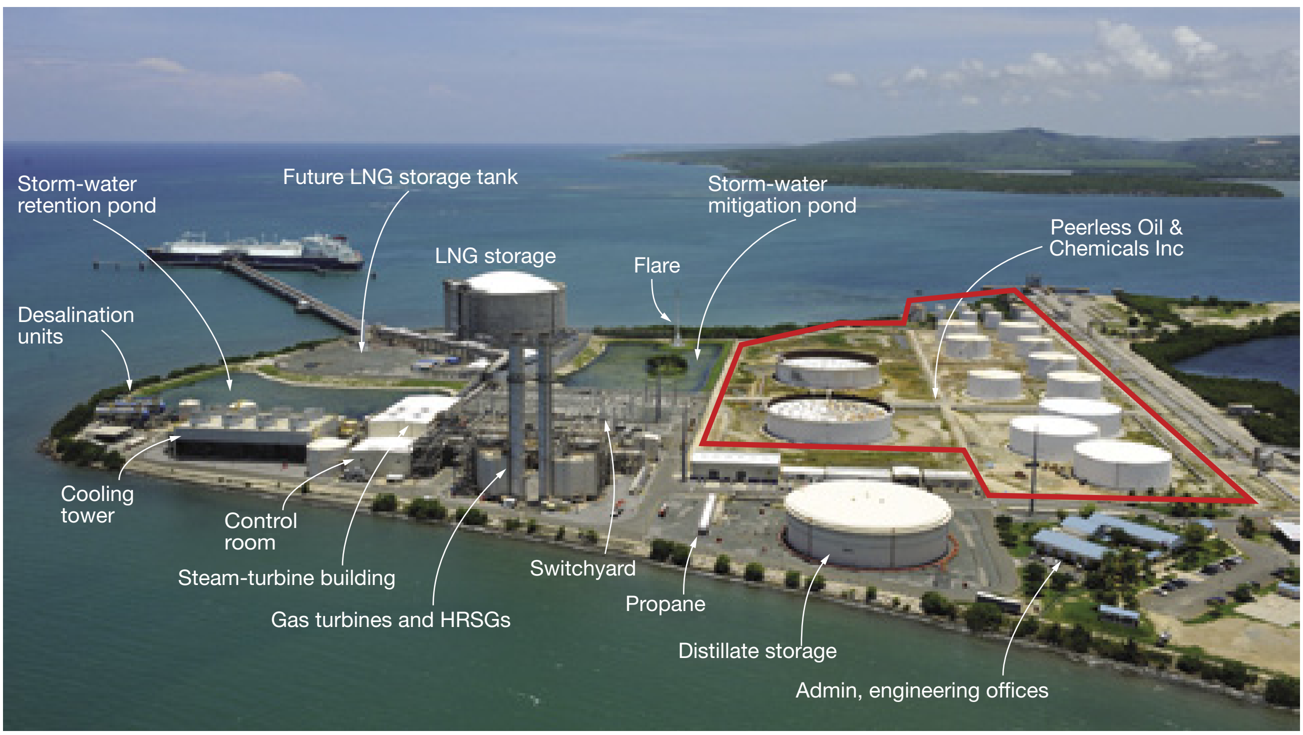
Leadership, skill, attitude, community key to vital plant's success in delicate ecosystem

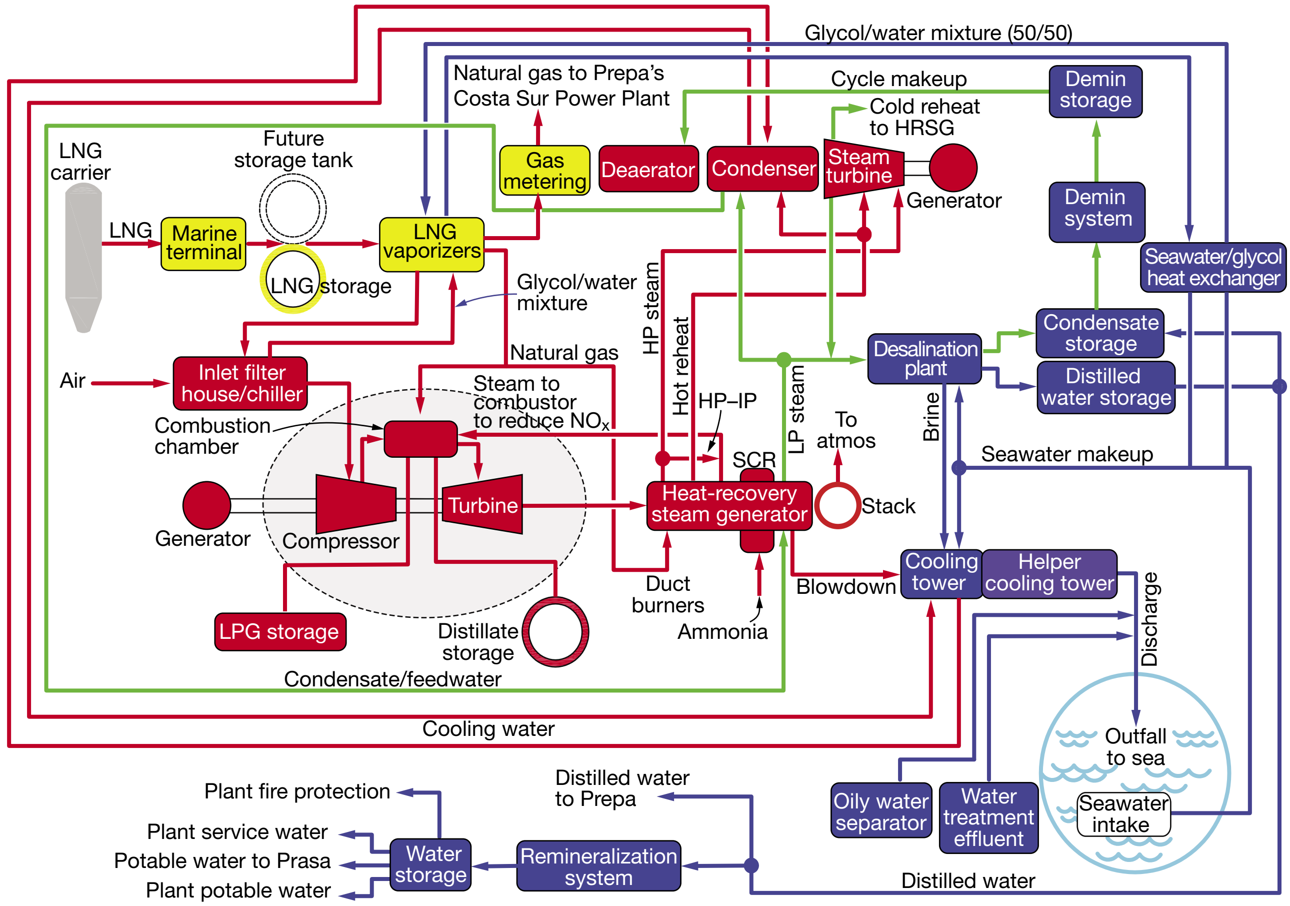
EcoElectrica LP, located on the southern coast of Puerto Rico in Punta Guayanilla (municipality of Penuelas) a few miles west of Ponce, is critical to the economic health of the Commonwealth. One of the cleanest generating stations in the world and a staunch protector of the local environment, EcoElectrica's 507-MW 2 × 1 F-class combined cycle burns liquefied natural gas (LNG) to produce 16% of Puerto Rico's electricity (Fig 1). It also receives 30% of the fuel burned on the island for electric generation through its terminal.

When EcoElectrica began commercial operation in March 2000 as Puerto Rico's first independent power producer (IPP), it was the only generating station in the world with an integrated LNG terminal (Fig 2). It continues as the only such facility in the Western Hemisphere today, according to the CCJ's editorial researchers. Although there are several LNG terminals in the Americas supplying pipelines that deliver gas to generating facilities, they do not benefit economically from the integration of power and regasification operations as does EcoElectrica.

Capturing the heat for regasification from the air inlets to the gas turbines, and from plant cooling water, allows the 501FC engines to operate year-round at rated output independent of ambient temperature



1. EcoElectrica shares a small peninsula with Peerless Oil & Chemicals Inc that juts out into Guayanilla Bay and the Caribbean Sea beyond. Here an LNG tanker discharges its cargo to the 1-million-bbl storage tank via a pipeline mounted on the causeway connecting the plant site to the unloading dock



2. Integrated fuel supply and plant process block diagram shows EcoElectrica provides four products to offsite customers: electricity, potable water, distilled water, and natural gas. Note that the actual steam-turbine arrangement is shown in Fig 22 (p 32) with nominal steam pressures and temperatures for base-load operation

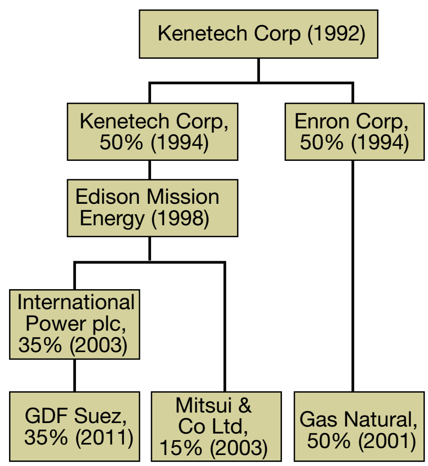
and reduces the combined-cycle heat rate to save about $9 million in fuel cost annually.

In 2012, EcoElectrica expanded the regasification capacity at its terminal to supply fuel to two nominal 400-MW conventional steam units at Puerto Rico Electric Power Authority's (Prepa) Costa Sur Power Plant a couple of miles away. The boilers at that facility, installed 40 years ago and designed to burn only No. 6 oil, were re-equipped for dual-fuel operation in 2011.

Costa Sur currently receives 93 million standard cubic feet per day (scfd) of gas from the EcoElectrica terminal—enough to produce about 400 MW. Output could double if required additional FERC permits are received.

Prepa is the offtaker for all the power produced by the independent generator, which also provides grid ancillary services—such as reactive power, frequency control, and spinning reserve. In addition, EcoElectrica supplies the utility distilled water from its 2-million-gal/day desalination facility and sells excess potable water to the Puerto Rico Aqueduct and Sewer Authority (Prasa).

The electric-power supply contract with Prepa is for 22 years; dispatch is by grid operators between 54% and nearly 100% of the generating plant's full-load rating. Price of power is fixed annually for up to 76% of rated output; above that level the price is based on spot offers. EcoElectrica is required by the utility to maintain its availability at a minimum of 93%; plus, thermal efficiency must be at least 45%. Regarding gas supply, Prepa contracts for LNG directly; EcoElectrica is paid a fee for LNG handling, storage, and



3. Project ownership changes over the years reflect the boom-and-bust cycle that characterized the independent power business in its early years of development. EcoElectrica's ownership stabilized shortly after commercial operation was achieved in March 2000. Recall that Kenetech Corp and Enron Corp no longer are in business, and Edison Mission Energy recently filed for bankruptcy.

International Power plc was formed in 2000 when National Power plc—created in 1990 when the UK electric industry was privatized—divided its assets into national and international operations. In 2012, GDF Suez, a French multinational electric and gas company formed by the merger of Suez SA and Gaz de France in 2008, completed its acquisition of International Power, making GDF Suez the world's largest independent power producer.

Gas Natural SA of Spain was involved only in the gas business when it acquired Enron's share of EcoElectrica in 2001. In 2009, the company bought Union Fenosa SA, a Spanish electric and gas utility

1. Talented, empowered staff the force behind EcoElectrica's success

EcoElectrica's primary business objective is to provide reliable, flexible, and efficient energy production and tolling services while excelling in safety, environmental preservation, regulatory compliance, and community relations. These words are not window-dressing: They are the personal goals of the dedicated employees who make this electric generating facility in Penuelas, PR, world-class.

Day-to-day leadership of EcoElectrica is provided by co-general managers: Carlos A Reyes, PE, for operations; Jaime Sanabria for finance and administration. They report to a Board of Directors representing the three owners: GDF Suez, Mitsui & Co Ltd, and Gas Natural Fenosa.

The facility is staffed by 78 employees, the majority assigned to O&M of the power block, desalination plant, and LNG terminal (chart).

Approximately 90% of EcoElectrica's personnel are "locals," living within about 30 minutes of the plant. One-third of the employees have Bachelor's degrees, 10% Master's degrees, and one a Doctorate. This is highly unusual in the power generation business today. Several first-line managers also are licensed professional engineers as the O&M org chart attests.

Carlos A Reyes, PE, general manager of operations

- Human resources: Damaris Rivera
- Purchasing: Marta D Velazquez

Mechanical maintenance	Engineering, E/I maintenance	Operations	LNG terminal	Environmental compliance	Health and safety
Wilbert De La Paz	Gaspar Bibiloni, PE	Adolfo Antompietri	Oscar Cedeno, PE	Damaris Negron-Alvarez	Pedro Martinez
Plant engineer Supervisor Technicians (5) *Planner* *Warehouse coordinator* *Facilities maintenance* *Runner*	Plant engineers (2) Performance engineer Supervisor DCS specialist I&C technicians (4) *Admin assistant*	Supervisors (5) Technicians (25) Chemist	*Admin assistant*	Plant engineer *Admin assistant*	Safety specialist

Personnel resources shared with other departments are in italics

The EcoElectrica organization is lean. More than 85% of the employees are assigned to specific tasks within the O&M organization, as the chart reflects. Department heads are identified within the function blocks

regasification, and for delivery of the product gas to Costa Sur.

The facility's business success is attributed in large part to its knowledgeable and loyal can-do workforce and to the plant's proactive social and environmental programs. The owners (Fig 3) have never wavered from their strong support of employee and local-area education initiatives, and of environmental protection.

Examples of ongoing investments in education and community development are substantial and include the following:

- Annual scholarships for 40 graduates of local high schools.
- Learning materials for two-dozen schools in the area.
- Sponsorship of science fairs.
- Contributions to local community and civic organizations.

Evidence of the deep concern for the environment shared by both the ownership team and plant personnel include the programs EcoElectrica supports and conducts internally as well as through local institutions—such as the University of Puerto Rico (UPR). Projects that illustrate the level of commitment to the environment include these:

- Removal of coral and sea grass prior to LNG terminal construction and their transplant after project completion.
- Mangrove planting.
- Ongoing aerial manatee survey.
- Construction of a mitigation pond for university research.
- Rescues of marine animals.

The plant has received nearly two dozen awards over the years for its community and environmental work and for its sterling safety record. Continuity of success and top performance speak volumes about the quality and commitment of both the facility's leadership and its workforce (Sidebar 1).

LNG terminal

You're almost sure to find mention of LNG somewhere in the news on a daily basis. Back in 2008, when the Henry Hub price of natural gas reached

2. LNG backgrounder

Liquefied natural gas is odorless, colorless, non-corrosive, and non-toxic. When vaporized and mixed with air, it burns only in concentrations of 5% to 15%. Neither LNG, nor its vapor, can explode in an unconfined open environment, according to information provided by CH-IV International, a unit of MPR Associates Inc, Alexandria, Va. CH-IV provides engineering services related to the design and operation of LNG facilities.

Natural gas is composed primarily of methane, but may also contain ethane, propane, and heavier hydrocarbons. Small quantities of nitrogen, oxygen, carbon dioxide, sulfur compounds, and water also may be found in pipeline natural gas, but they are removed during liquefaction.

LNG usually is referred to as light or heavy depending on its methane content, which ranges from about 82% (heavy) to 99% (light) depending on the source and type of processing. The methane fraction for a typical shipment received by EcoElectrica from its primary supplier, Atlantic LNG Co of Trinidad, is in the neighborhood of 96%. The table presents the range of LNG compositions used in the design of the EcoElectrica terminal.

The composition of LNG changes during tanker transport because some of it evaporates. The more volatile methane evaporates faster than the heavier hydrocarbon components, thereby increasing the gross calorific value of the fuel. Effects of ageing should be considered by the user prior to delivery, especially if a long voyage is involved.

LNG tanks always are of double-wall construction with an efficient insulation system between the walls. Large tanks (EcoElectrica's is 42-million gal) are cylindrical in design and have a domed roof; they are characterized by a low ratio of height to diameter. Storage pressures in these tanks are low—less than 5 psig, according to CH-IV engineers. LNG must be maintained cold—below about minus 180F—to remain a liquid, independent of pressure.

Small tanks, those having a capacity of 70,000 gal or less, generally are horizontal or vertical vacuum-jacketed pressure vessels. Range of design pressures for these containers extends from less than 5 to more than 250 psig.

The insulation, as efficient as it may be, will not keep the LNG reservoir in its liquid state. CH-IV experts explain that LNG is stored as a "boiling cryogen"—that is, as a very cold liquid at its boiling point for the storage pressure maintained. They suggest thinking of stored LNG as analogous to boiling water—only 470 deg F colder. The temperature of an open pot of boiling water does not change, even when more heat is applied, because it is cooled by evaporation.

In much the same way, the experts continue, LNG will remain at near constant temperature if maintained at constant pressure—a phenomenon called "auto-refrigeration."

EcoElectrica designed for a wide range of LNG compositions

Component	Rich (heavy) LNG	Lean (light) LNG	Typical LNG
Methane, mol %	81.98	99.02	96.29
Ethane, mol %	16.02	0.0	3.21
Propane, mol %	1.50	0.0	0.4
n-Butane, mol %	0.0	0.0	0.1
i-Butane, mol %	0.0	0.0	0.0
n-Pentane, mol %	0.50	0.0	0.0
i-Pentane, mol %	0.0	0.0	0.0
Nitrogen, mol %	0.0	0.98	0.0
Molecular weight	19.0	16.2	16.65
Hydrogen sulfide, ppmv	Nil	Nil	Nil
Total sulfur, ppm	Nil	Nil	Nil
Mercaptan sulfur, ppb	Nil	Nil	Nil

As long as the LNG boil-off gas (BOG as it is called) is allowed to leave the storage tank, the temperature remains constant. If BOG were not removed, then the pressure inside the tank would rise. Example: At 100 psig, LNG temperature would be minus 200F. However, the cost of building a 1-million-bbl pressure vessel for LNG storage would be prohibitively expensive.

Safety. No discussion on the handling and storage of *any* fuel is complete without a thorough review of safety history, procedures, and best practices. The most serious US accident involving LNG occurred in Cleveland in 1944 before the behavior of cryogenic liquids in storage was well understood. The space program contributed significantly to the collective knowledge on cryogenics and post-Cleveland there have been only two safety incidents related to domestic LNG facilities, according to CH-IV research:

- A construction accident on Staten Island 40 years ago that has been cited by some as an LNG accident because it involved work inside an empty and warm storage tank.
- The failure of an electrical seal on an LNG pump in 1979 permitted natural gas to enter an enclosed building and a spark of indeterminate origin caused an explosion. Revisions to the electrical code since that time would prevent such an accident from occurring today.

CH-IV International offers a detailed history of accidents at LNG facilities onshore and offshore worldwide on its website at www.ch.iv.com. In addition, and perhaps more importantly, its experts discuss the mechanics of gas explosions—including the vaporization of LNG spills and the mixing of the resulting vapor with air, ignition sources, and ignition of an LNG vapor cloud.

almost $14/million Btu, the focus was on import terminals and regasification facilities (in June 2012, 91 were operating worldwide). Then the price plummeted to less than $2 in 2012, courtesy of shale-gas production, and the focus shifted to liquefaction facilities and export terminals (25 worldwide in June 2012).

The environmental benefits of gas have increased demand for the fuel, and also contributed to the interest in inland peak-shaving facilities for storing and vaporizing LNG on an intermittent basis to meet short-term peak requirements. More than 260 of these facilities were in service worldwide as of June 2012, some operating since the mid-1960s, according to the experts at CH-IV International, located in Hanover, Md, and Houston. This number does not include the many small vehicle fueling stations and industrial LNG facilities around the globe.

But to nearly all personnel at gas-turbine-powered simple- and combined-cycle facilities, LNG exists only as an acronym because it is regasified and injected into existing gas-pipeline infrastructure well before the plant boundary.

Natural gas condenses at atmospheric pressure only after cooling to about minus 260F. The LNG produced occupies 1/600 the volume of its gaseous cousin and generally can be transported and stored economically—assuming oil is used as the basis for comparison. Note that a gallon of LNG has a nominal energy content of 80,000 Btu; ultra-low-sulfur diesel oil contains about 138,500 Btu/gal.

4. Three of the four unloading arms support piping to transfer LNG from the ship's tanks to the 32-in. line that delivers fuel to the storage tank ashore; the fourth arm supports a vapor line

5. Fire suppression equipment is in close proximity to unloading arms

6. Pipe rack supports LNG supply line to shore, LNG recirc line, vapor line, seawater intake and discharge lines, and fire safety piping

7. Large line to right of pathway looking down to ship transfers LNG from ship to storage tank

While importing LNG to the mainland US at today's domestic gas prices is unlikely—except, perhaps, where pipelines are maxed out or unavailable—it makes perfect sense in ecologically minded Puerto Rico, which has no meaningful indigenous fuel resources. EcoElectrica is the industry's pioneer in the development of an integrated LNG/power generation system for the safe and efficient production of electricity with minimal environmental impact. Its LNG experience is particularly valuable to other power producers serving areas where traditional fuel supplies are constrained.

Reyes

Carlos A Reyes, PE, EcoElectrica's general manager of operations, led the discussion on LNG terminal design and operation between the editors and two of the plant's foremost experts on the subject: Oscar Cedeno, PE, LNG terminal manager, and Project Engineer Dr Jose M Rullan, PE.

By way of background, Reyes is a 30-yr industry professional who appreciates the value of gas-turbine user groups—in particular, the 501F Users Group. He came to EcoElectrica as plant manager in 2004 and was promoted to his current position three years later. Before that Reyes spent 17 years with Prepa, seven of those as the head of operations for the island's electric system, and three years with coal-fired AES Puerto Rico LLC, leaving that assignment as VP engineering.

An hour-long interview and follow-on tour of offloading operations revealed a relatively simple system and familiar equipment for unloading, onsite transport, storage, and regasification of LNG. However, the fuel's idiosyncrasies—such as its extremely low temperature and behavior in storage—spoke volumes about the respect LNG deserves and the knowledge and experience required to assure its safe and reliable use (Sidebar 2).

The EcoElectrica O&M team left no doubt that safety was of primary importance both in terminal design and operation. Certification to OHSAS 18001, the global occupational health and safety management standard, is evidence of the efforts undertaken at the plant to assure a safe and healthy work culture. Reyes pointed to a long list of regulations and enforcement agencies, both national and local (Sidebar 3), to assure the facility would maintain the unblemished safety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record compiled during his tenure (no lost-time accidents last nine years). Protection of the environment and security, both often linked to safety, also have a high profile in that list of agencies.

Cedeno and Rullan described the terminal and its operation beginning with the docking of a tanker. The S/S Sestao-Knutsen's cargo of 867,990 bbl of LNG was offloaded to the 1,006,400-bbl storage tank during the editors' visit (Sidebar 4). That's enough fuel to operate EcoElectrica for about 40 days, assuming no gas delivery to Costa Sur.

The S/S Sestao-Knutsen is typical in terms of size for an LNG tanker. Nearly 70% of the more than 350 vessels in the global LNG fleet carry between 820,000 and 940,000 bbl. Such vessels typically travel routes of from 1500 to 6000 nautical miles, but the S-K's voyage from Trinidad is only around 560 miles.

The dock is located about 1700 ft offshore as shown in Fig 1. Four unloading arms support cargo operations: Three handle liquid LNG, one natural gas (Figs 4, 5). The pipe rack on the causeway from the ship to the shore (Fig 6) includes the following:

- A 32-in.-diam LNG line capable of delivering nearly 40,000 gpm of fuel to the storage tank (Fig 7).
- A 6-in. recirc line that moves LNG from the storage tank to the pier on a continuous basis for a return trip through the 32-in. pipe to keep it cool when a ship is not unloading—this to prevent thermal cycling. There are 12 expansion joints in the 32-in. line and each would expand by 1 ft if the pipe were allowed to return to ambient temperature after a fuel delivery. Regulations require internal inspection of the line every five LNG/ambient temperature cycles, so avoiding them is critical.

3. Regulatory oversight focuses on safety, environmental protection

Integrating an LNG terminal with a powerplant significantly increases the number of regulations and permits governing facility design and operation compared to those required for a standalone combined cycle. Plus, with more federal and local agencies involved, there's greater regulatory oversight of facility operations to assure compliance with the additional rules.

Here's a list of the regulatory agencies monitoring activities at EcoElectrica and what their responsibilities are:

Federal agencies

Federal Energy Regulatory Commission (FERC) approval is required for the siting of new onshore LNG facilities. The Energy Policy Act of 2005 designates FERC as the "lead agency for the purposes of coordinating all federal authorizations" and the agency responsible for complying with federal requirements under the National Environmental Policy Act of 1969.

FERC also is responsible for monitoring the safety and security of operating LNG facilities on an ongoing basis, coordinating its efforts with the US Coast Guard (USCG) and the Dept of Transportation (DOT). While DOT and FERC have agreed that the former has exclusive authority to promulgate federal safety standards for LNG facilities, the latter can issue more stringent safety requirements when it believes they are warranted.

The agency monitors LNG terminal activities in accordance with 18CFR153, "Applications for Authorization to Construct, Operate, or Modify Facilities Used for the Export or Import of Natural Gas"; 18CFR380, "Regulations Implementing the National Environmental Policy Act"; and NFPA 59A, "Standard for the Production, Storage, and Handling of LNG."

Compliance involves semiannual reporting and an annual audit.

Dept of Homeland Security (DHS)/ US Coast Guard (USCG) assure facility security compliance in accordance with 33CFR101, "Maritime Security: General"; 33CFR105, "Maritime Security: Facilities"; and 33CFR127, "Waterfront Facilities Handling LNG." The USCG acts as a cooperating agency in the evaluation of LNG terminal applications and has the authority to review, approve, and verify plans for marine traffic around proposed onshore LNG terminals as part of the overall siting approval process led by FERC.

Annual inspections of security and maritime operations are conducted according to the requirements of the Maritime Transportation Security Act. Inspections also are conducted of each LNG unloading operation.

Environmental Protection Agency (EPA) assures compliance with air emissions in accordance with provisions of the Clean Air Act (CAA); discharges of storm and waste waters in accordance with the National Pollutant Discharge Elimination System (NPDES), and the control of hazardous wastes from cradle to grave in accordance with the Resource Conservation Recovery Act (RCRA).

Compliance includes continuous monitoring of air emissions (CEMS) and periodic reporting as required by NPDES and RCRA. Relative Accuracy Test Audits (RATA) are completed annually; plus, the agency conducts unannounced inspections to assure compliance with air and water permit requirements.

DOT's Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for developing and enforcing regulations for the safe, reliable, and environmentally sound operation of the nation's pipeline infrastructure. It assures compliance with 49CFR193, "LNG Facilities: Federal Safety Standards" and 49CFR192, "Transportation of Natural Gas by Pipeline: Minimum Federal Safety Standards." The latter pertains to the pipeline that delivers gas from EcoElectrica's LNG terminal to Prepa's Costa Sur Power Plant. Annual reporting and inspections are required for compliance.

Occupational Safety & Health Administration (OSHA) assures compliance with 29CFR1910, "Occupational Safety and Health Standards," and 29CFR1917, "Marine Terminals." OSHA recommends safety training requirements—including such things as fall protection, confined-space entry, electrical safety, etc.

Puerto Rican agencies

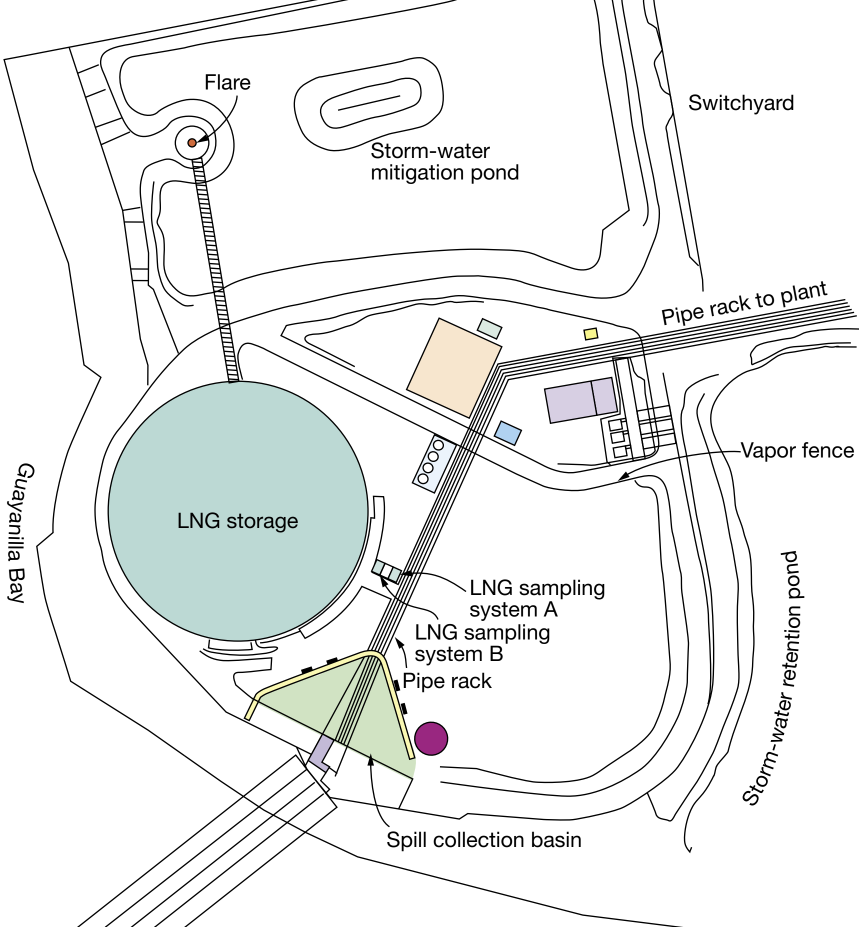
Public Service Commission works in concert with DOT's PHMSA on pipeline safety (see above). It is certified by DOT to regulate, inspect, and enforce intrastate natural-gas pipeline safety requirements.

Police Dept is responsible for licensing and auditing of facilities handling and transporting explosive substances. Audits are conducted twice annually.

Fire Dept is responsible for the annual inspection and certification of firefighting systems.

Dept of Labor assures compliance with pressure-vessel codes. It inspects and certifies pressure vessels and cranes yearly.

Dept of Health verifies compliance with potable water standards and the facility's sanitary license. Reporting of monthly sampling and monitoring activities is required.

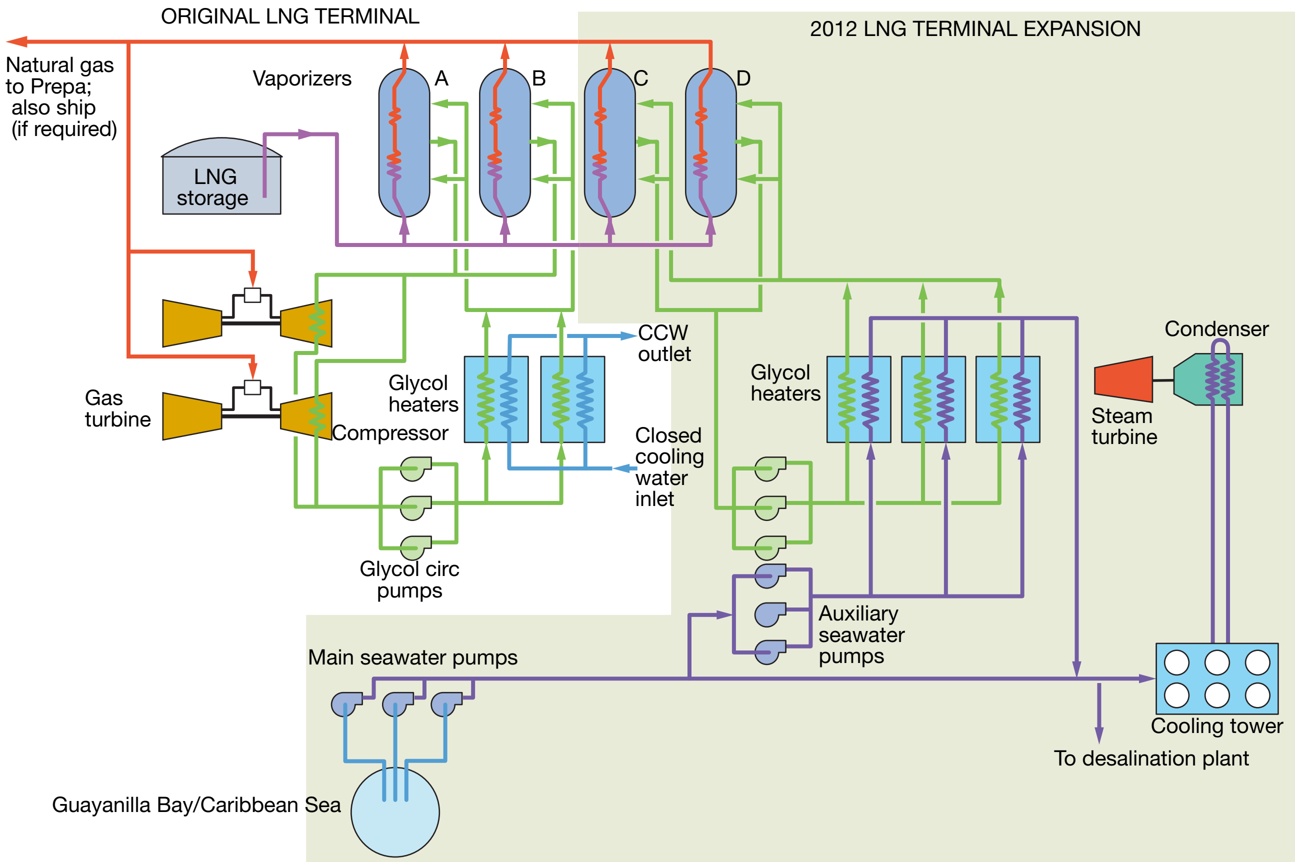


8. Onshore LNG infrastructure. Important takeaway from this drawing is the location of critical impoundments—spill collection basin and storm-water mitigation and retention ponds—relative to LNG storage and handling systems

Absent five thermal cycles, the line must be inspected only once every five years.

- A two-way, 10-in. vapor line that allows gas released from the surface of the onshore LNG tank during unloading operations to return to the ship to fill the voids created in the cargo tanks as LNG is removed. This allows the entire fluid system (shipboard cargo tanks, transport pipe, and shore-side LNG tank) to remain in equilibrium when unloading.

A layout of the onshore LNG infrastructure is shown Fig 8. Note the spill collection basin where the pipes on the causeway rack interface with those connecting to the storage tank. The basin is designed to retain, in the unlikely event of a pipe failure, all the LNG flowing through the 32-in. line for a period of 10 minutes (about 10,000



9. LNG terminal at EcoElectrica has two vaporization systems, each equipped with a pair of vaporizers arranged in parallel. The original system (vaporizers A and B), designed to serve only the combined-cycle plant, gasifies LNG using heat picked up by the 50/50 solution of glycol and water as it circulates through the GT inlet chillers and through the heat exchangers serving the closed cooling water (CCW) circuit. The new system (vaporizers C and D), installed to provide fuel gas to the conventional boilers at Prepa's Costa Sur Power Plant, gasifies LNG with heat extracted from seawater. Note that the components labeled "glycol heaters" are plate-and-frame heat exchangers

4. Safety paramount in the design of LNG tankers

Personnel at electric generating plants powered by combustion turbines know that natural gas is an inherently safe fuel to transport, store, handle, and burn. For gas to explode, it must be mixed uniformly with air in a concentration of from 5% to 15%, confined in an enclosed space, and ignited.

Preventing uncontrolled releases of gas is the first step in assuring a safe working environment. LNG tankers are conservatively designed to protect against the release of gas in the unlikely event of hull damage. Jeffrey P Beale, president, CH-IV International, describes the three basic types of cargo tank designs in his report, "The Facts About LNG," available at www.ch-iv.com:

Self-supporting spherical. These ships are easily recognized by the four or five hemispherical domes that protrude above the main deck. The LNG tanks are protected by their location—a significant distance from the vessel's double hull at the waterline—as well as by a support skirt of high-tensile-strength steel the vicinity of the waterline.

Self-supporting prismatic-shaped cargo tanks conform more closely to the shape of the ship's hull than do spherical ones. Typically, vessels have three or four of these tanks, fabricated independently of the hull and lifted by crane into place; they also have a flat-looking main deck, one resembling that of a conventional crude-oil carrier. Horizontal and vertical stiffeners and bulkheads strengthen the cargo tanks and lock them into position within the hull.

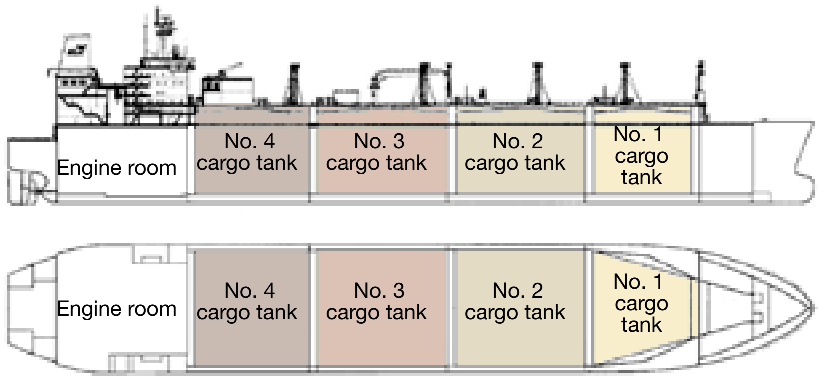
Membrane-type LNG carriers are double-hulled—the inner hull supporting the cargo tanks with webs and stiffeners (Fig A)—and usually are characterized by a beveled, raised structure above the main deck as Fig B shows. The general appearance of membrane-type carriers is similar to that of self-supporting prismatic-shaped vessels.

Cargo tanks have several levels of protection, as illustrated in Fig C, including the following:

- A nominal ⅜-in.-thick primary membrane fabricated of stainless steel or Invar. Note that the latter, an alloy containing 36% nickel and 64% iron, has a very low coefficient of thermal expansion.
- A nominal ⅜-in.-thick secondary membrane of alloy steel separated from the primary membrane by about a foot of perlite insulation. Perlite is a naturally occurring, lightweight volcanic glass.
- Another foot or so of perlite separates the secondary membrane from the nominal 1-in.-thick inner hull.
- The outer hull (1 to 1½ in. steel plate) forms a ballast tank with the inner hull. The inner and outer hulls are separated by a distance of about 8 to 10 ft.

The S/S Sestao-Knutsen shown in Fig B is typical of the LNG carriers that serve EcoElectrica. It was delivered in late 2007 by Knutsen OAS Shipping of Haugesund, Norway to Stream, a 50/50 joint venture between Repsol and Gas Natural Fenosa for trading, wholesaling, and transporting LNG. Capacity of the vessel, which has an overall length of 933 ft and a beam of 139.4 ft, is 867,990 bbl. Summertime draft is 40.4 ft when the vessel is full. It takes about 16 hours to discharge a complete load of LNG from the vessel.

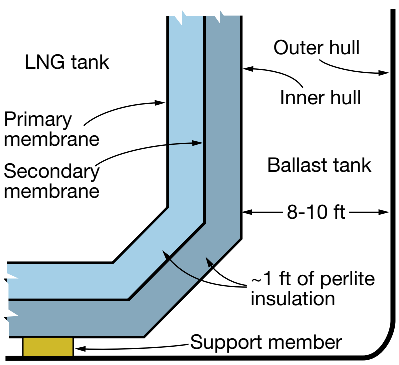
S/S Sestao-Knutsen's officers hosted the editors during their visit to EcoElectrica. The cross-compound steam turbine plant in Fig D is capable of driving the vessel at speeds up to 19.5 knots. LNG that vaporizes during transport is burned in the ship's dual-fuel boilers.



A. Membrane-type LNG carrier generally is arranged as the drawings above indicate

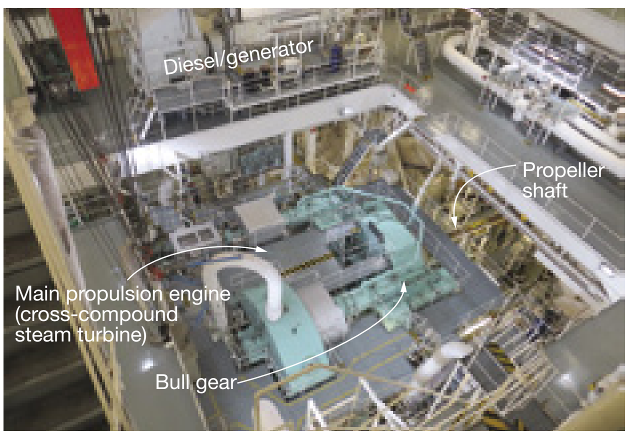
Diego Moreno, MarineTraffic.com

B. S/S Sestao-Knutsen can deliver its payload of nearly 1 million bbl of LNG in less than 16 hours



C. LNG tanks are well protected by distance against any hull penetration (left)

D. Steam for the main engine is provided by boilers burning LNG that vaporizes during the voyage (right)



bbl). This is a code requirement.

Located between the storage tank and the shore-side pipe rack are systems for sampling incoming LNG every four minutes during the unloading process to verify that the product being unloaded meets specifications and is compatible with LNG already in the tank. This is particularly important for avoiding rollover and operating problems associated with it (Sidebar 5). The homogeneity of the LNG in storage is maintained by continuous recirculation of the fuel between deliveries.

Plant personnel rely on data from tests of LNG samples to calculate the Modified Wobbe Index (MWI) for analyzing the expected impacts of fuel variations on gas turbine operation. In mathematical terms, the MWI is equal to the lower heating value of the fuel in Btu/scf divided by the square root of the absolute temperature of the gas fuel (deg R) multiplied by the ratio of the molecular weight of the gas fuel to that of dry air.

In more simple terms, MWI is the ratio of energy density to the relative density of the fuel. Because control of a gas turbine depends on regulating energy input to the engine, a variation in the MWI will dictate a change in the volumetric fuel flow to the machine.

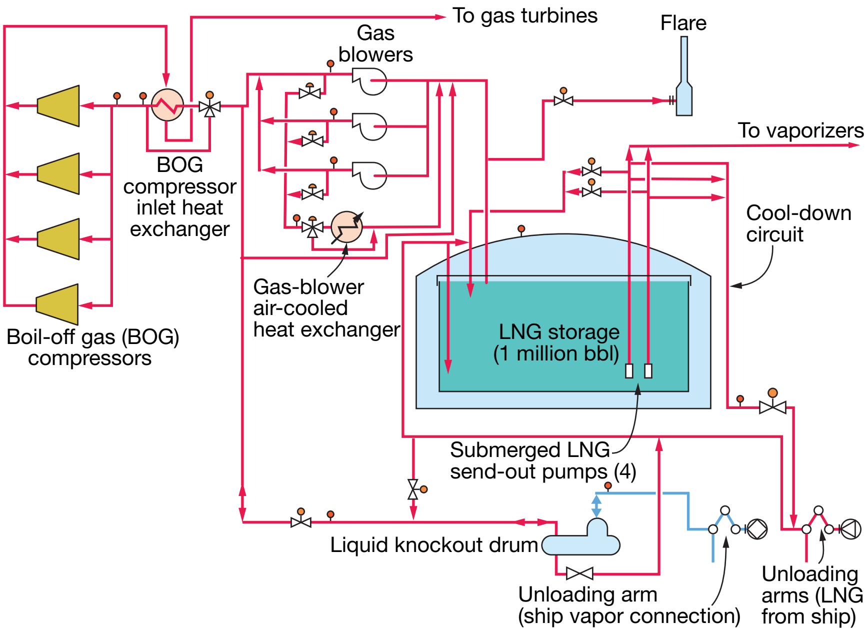
To illustrate: When MWI increases, volumetric flow decreases; when MWI decreases, as it does when natural gas is blended with, or replaced by, a fuel of lower heating value, fuel flow must increase. Most combustion systems can accommodate changes in MWI that extend from 95% to 105% of the design value before hardware or operational changes are required.

Terminal infrastructure. Figs 9 and 10 illustrate how the storage tank is integrated into the terminal fluid systems; Fig 11 gives details on tank design. Both Figs 10 and 11 show the tank can be filled from the top or the bottom, depending on the characteristics of LNG in the tank and that being unloaded. The table in Sidebar 2 reveals the wide variations in LNG composition possible, depending on the source.

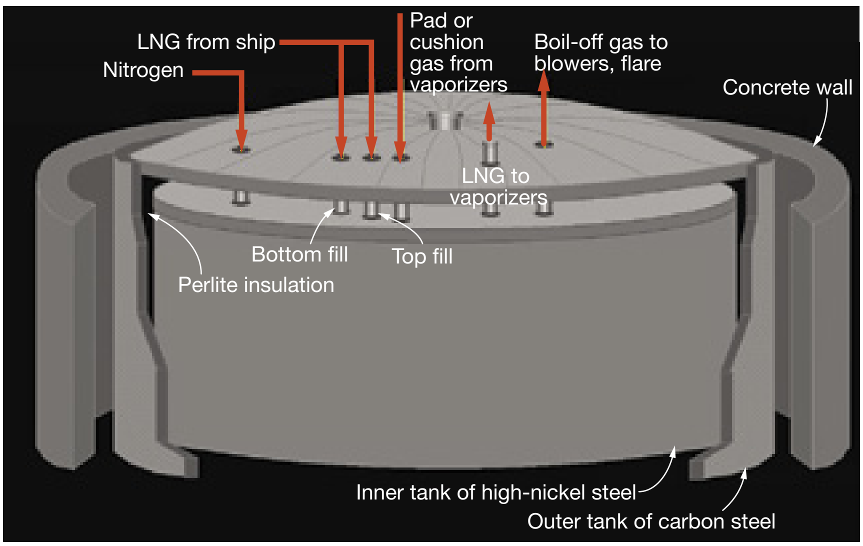
The reinforced-concrete cylinder that encircles the double-wall storage tank—inner tank constructed of 9% nickel steel and the outer tank of carbon steel separated by a thick layer of perlite insulation—offers protection against a Category 5 storm. It also prevents the release of LNG to the environment in the unlikely breach of both tank walls. Regulations require spill containment equivalent to 110% of storage-tank capacity. At EcoElectrica, the nominal 10-ft annulus formed by the inner diameter of the concrete cylinder and the outer diameter of the steel secondary containment vessel is sufficient to retain up to 150% of tank capacity. Any rainwater accumulating in the annulus is pumped to the 30-million-gal storm-water retention pond.

Important standards governing the design of LNG terminals include the Dept of Transportation's (DOT) 49CFR193, "LNG Facilities: Federal Safety Standards." CFR is the acronym for the *Code of Federal Regulations.* This standard relies heavily on NFPA 59A (2001 edition), "Standard for the Production, Storage, and Handling of LNG." For EcoElectrica, compliance with 49CFR192, "Transportation of Natural Gas by Pipeline: Minimum Federal Safety Standards," also was necessary because it is responsible for the delivery of gas to Prepa's Costa Sur.

Among the safety features incorporated into EcoElectrica's LNG terminal



10. LNG unloading and boil-off circuits. Blowers take gas from above the liquid line in the storage tank and push it to compressors for delivery to the gas turbines. The cool-down circuit on the right side of the diagram maintains the 1700-ft pipe run from unloading dock to shore at LNG temperature to prevent thermal cycling of the line. Also important: There are three unloading arms for transferring LNG from the ship to the pipeline supplying the storage tank onshore. A fourth arm transports boil-off gas (BOG) from the storage tank to the ship's tanks to equalize pressure throughout the system during unloading



11. LNG storage vessel for EcoElectrica consists of an inner tank made of high-nickel steel that is separated from an outer carbon-steel tank with a floating roof by 6 ft of insulation. A concrete wall capable of withstanding a Category 5 storm encircles the steel containers. A system of pumps removes water that collects in the nominal 10-ft annulus formed by the wall and the outer steel tank

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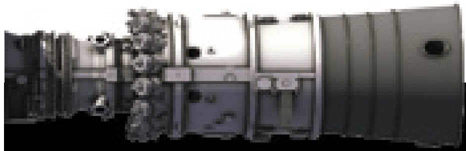
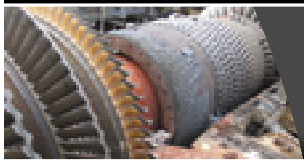
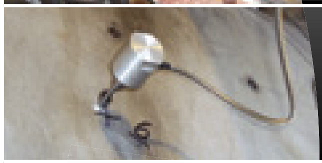
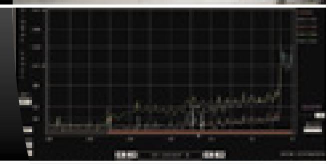
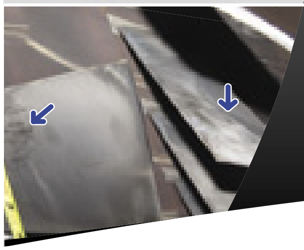


ACTMS™ On-line Stator Vane Crack Detection			AMS™ HRSG Leak Detection	
	• Cracking/liberating vane through turbine • Stationary airfoil cracking • Rubbing, loosening and blade clash • $7 to 10 million per incident	**PROBLEM**	• Tube stub weld leaks at the SH & RH headers • Tube leaks at the SH and RH Drains • Inability to locate area of the leak	
	• Non-intrusive sensors • After-market install • Complete forward compressor coverage	**IN SERVICE**	• Non-intrusive sensors • After-market install • 24-7 real time monitoring • Total HRSG coverage or in areas of most concern	
	• Defect source location • Graphical displays • Local and network alarming	**REAL TIME**	• Trend severity and progression of leak • Locate area of leak before unit removed from service • Local and network alarming	
	• On-line detection of vane cracking • Insight to unknown condition • Optimize remaining life • Early warning to prevent failure	**RESULTS**	• On-line tube leak detection • Early warning to prevent failure • Manage market exposure and risk • Tube leak repair during planned outage or period of low demand	

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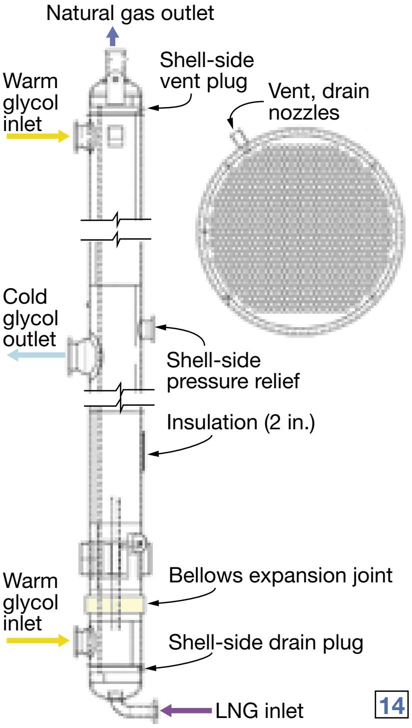
12-14. Two vaporizers (A and B, Fig 12) were incorporated into the original terminal as Fig 9 illustrates. Those two heat exchangers are shown at the left in Fig 13; vaporizers C and D, at the right, were commissioned in 2012 to serve Prepa's Costa Sur Power Plant. Containers in the foreground hold parts and tooling for the next outage. Fig 14 shows vaporizers are relatively simple shell-and-tube heat exchangers, constructed of Type 304 stainless steel and measuring 40 ft in length between tubesheet faces. Shell diameter is 32 in., shell wall 0.3125 in. Tubes are 0.75 in. diam x 0.065 in. wall. Maximum allowable working pressures are 275 psig on the shell side, 1175 psig on the tube side; design temperatures for shell and tubes are 100F. Design can accommodate a 200-mph wind loading



are the following:

- A flare is provided to burn off excess gas released in the storage tank during unloading operations, or when the plant is operating on propane.
- A fence is installed to mitigate vapor release from the terminal area. An unintended release of LNG would hug the ground because of its low temperature and higher density compared to air; the fence serves as a barrier to prevent its aimless migration.
- Gas and flame detectors are strategically positioned at all joints in the LNG tank.

There are four submerged LNG sendout pumps installed at the bottom of the storage tank. The discharge lines from all pumps are connected to the

15-17. Glycol heaters of the plate-and-frame type (Fig 15) transfer heat contained in seawater and supplied by the auxiliary pumps in Fig 16 to the 50/50 glycol/water mixture delivered by the pumps in Fig 17 (refer to layout in Fig 9)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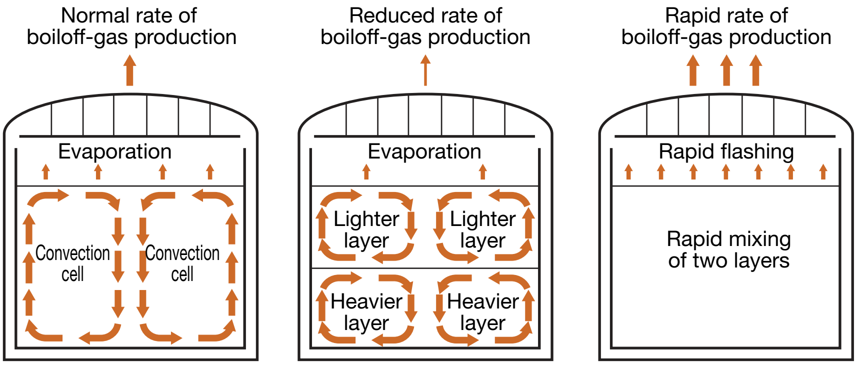
5. Rollover can quickly release large amounts of boil-off gas

Rollover, a phenomenon conducive to rapid pressurization of an LNG storage tank, is caused by heat leaking into a tank having two layers of LNG with different densities, Arthur Ransome, VP and GM for CH-IV International, told the editors. The following information was developed by Ransome and his colleagues:

To illustrate the concept of rollover, first examine the behavior of a homogeneous mixture of LNG in storage, as shown in Fig A. Here, the convective flow of heat leaking into the LNG creates a natural circulation. The "warm" fluid moves up the tank walls and across the liquid surface, where heat is released as gas boils off. Evaporation of the LNG reduces the surface temperature and the cooler liquid drifts downward, completing the cycle.

In a stratified tank (Fig B), the less-dense upper-layer convection proceeds normally, releasing heat in the same manner as the homogeneous case. However, the convective boundary in the dense lower layer is unable to penetrate the upper layer and it forms its own convection pattern. Heat leaking into the lower layer cannot be removed by surface evaporation, so the thermal energy remains trapped. As the temperature of the lower layer increases, its density decreases.

When both layers achieve virtually the same density at the interface, very rapid mixing and the release of the suppressed boil-off occur, causing a rollover (Fig C). An actual flip-flop of the LNG layers does not happen, as the name infers; however, the speed at which heat transfer



A. HOMOGENEOUS LNG B. STRATIFIED LNG C. TANK EXPERIENCING ROLLOVER

proceeds can cause substantial turbulence in the tank. Rollovers can be relatively small and insignificant to the vapor handling system—or not. Sometimes, very substantial quantities of boil-off gas can be produced in a short period of time.

Stratification does not occur in a tank of homogeneous LNG. But the introduction of LNG of different density into a partially filled tank can lead to the temporary formation of stratified layers. Another point to remember: Stratification can occur in an idle tank over a long period of time.

The rollover phenomenon can be of sufficient consequence to the operator and owner of an LNG facility to warrant serious consideration on the methods of detection, prevention, and mitigation. There are a variety of techniques and equipment to accomplish these objectives. Perhaps the best way to get started in developing a stratification mitigation plan is to read through NFPA 59A.

Designers take note: The 2001 edition of NFPA 59A (the one referenced in DOT's 49CFR193 regulations on safety standards for LNG facilities) states in Section 4.1.2.4 that "all LNG containers shall be designed to accommodate both top and bottom filling unless other positive means are provided to prevent stratification."

Section 11.3.7 provides operations personnel and designers the following guidelines on bulk transfers into stationary storage containers:

- "The LNG shall be compatible in composition, or temperature and density, with the LNG already in the container."
- "Where the composition, or temperature and density, are not compatible, means shall be taken to prevent stratification, which might result in rollover and an excessive rate of vapor evolution. If a mixing nozzle or agitation system is provided, it shall be designed to have sufficient energy to accomplish its purpose."

LNG header supplying the four vaporizers and to the recirculation line that assures homogeneity of the product in storage. Two of the pumps also are plumbed to circulate LNG from the tank to the dock and back through the unloading line when a ship is not discharging cargo. You can trace these flow patterns in Fig 10.

Two vaporizers, A and B, were part of the original installation; C and D were added in 2012 to provide gas for Costa Sur (Figs 12-14). All are conventional shell-and-tube heat exchangers measuring 32 in. in diameter and 40 ft long between tubesheets. As Fig 14 shows, LNG received from the storage tank flows upward through the tube bundle, exiting from the top as a gas at about 72F. It can be directed to either the gas turbines or to the Costa Sur pipeline.

The warm 50/50 glycol/water mixture (nominally 75F) enters the shell side of the exchanger at two points—one near the bottom and one near the top—and exits in the middle at a nominal 50F. Vaporizers A and B are arranged to supply cool glycol to the inlet-air cooling coils in the gas-turbine filter houses as well as to the closed cooling water (CCW) system. The latter helps improve the performance of steam-turbine lube-oil coolers, GT auxiliaries coolers, generator exciter coolers, etc.

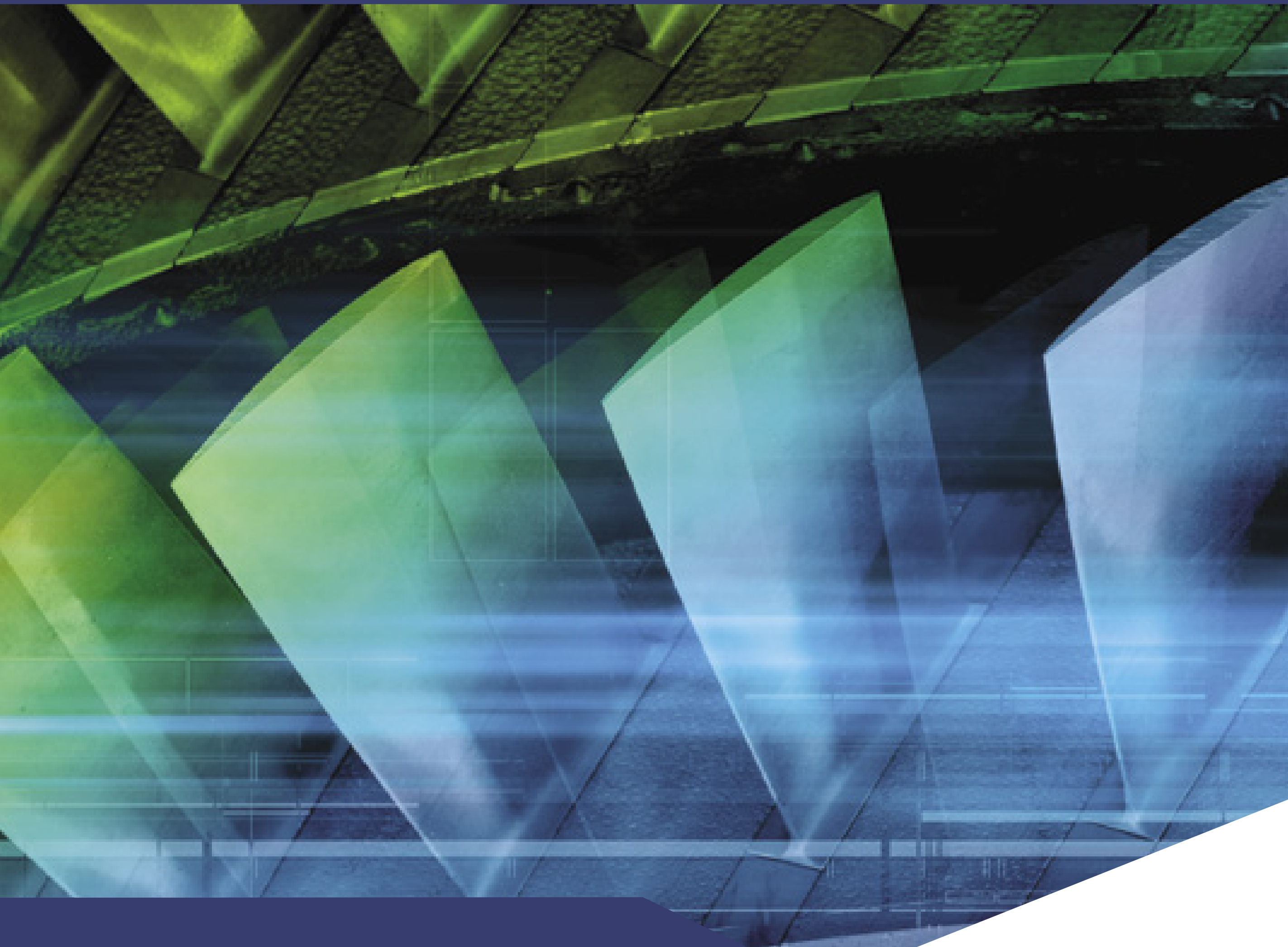
Glycol leaving vaporizers C and D cools seawater to boost the thermal performance of the condenser and the main heat rejection system. The plate-and-frame exchangers that enable heat transfer are shown in Fig 15. The auxiliary seawater pumps are in Fig 16 and the pumps that return warm glycol to the vaporizers for converting LNG to natural gas are in Fig 17.

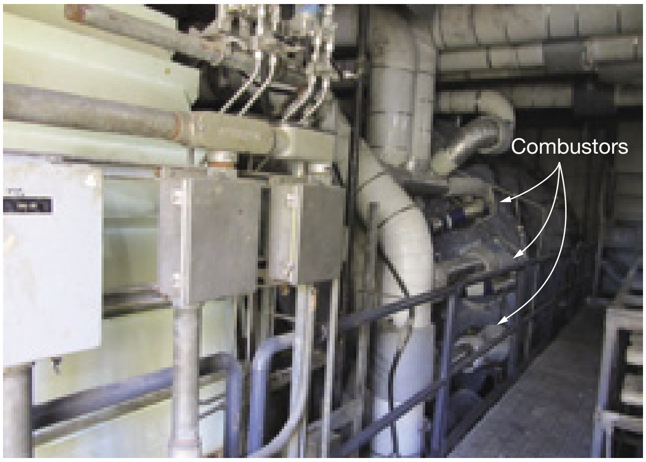
Gas that vaporizes from the surface of the LNG in storage—so-called boil-off gas (BOG)—is assisted by blowers to the suction side of compressors for delivery to the gas turbines or to Prepa. Plant personnel report that a significant maintenance effort is required to keep these gas-handling components in top condition.

Powerplant

At first blush, EcoElectrica's 2 × 1 F-class combined cycle appears ordinary; but it is not. The suppliers of main components tell part of the story:

- Two 501FC gas turbine/generators made by Westinghouse Electric Corp before Siemens AG purchased the company.





18. Three of the 501FC's combustors are visible from compartment door (left)

19. LPG is vaporized using water from the HRSG's HP economizer circuit. Gas passes through a liquids separator before flowing to the fuel-gas superheater, which preheats gas for the turbine to 250F (right)

- Two supplementary-fired heat-recovery steam generators designed and fabricated by ABB Combustion Engineering before Alstom purchased ABB.
- A single-casing, single-flow steam turbine/generator built by offshore manufacturer Toshiba Corp.
- Two 100% boiler-feed pumps for each HRSG purchased from Ingersoll-Dresser Pump Co—now part of Flowserve Corp.
- Surface condenser manufactured by Ecolaire before it was purchased by Alstom and later sold to current owner SPX Heat Transfer Inc.

Add to this short (15-year) historical perspective of an industry in transition the following facts: (1) Station equipment was ordered by Enron Equipment Procurement Corp, which went bankrupt before the plant had been in service for two years, and (2) EcoElectrica was the first IPP and gas-fired generating facility in Puerto Rico.

Ask yourself, were you managing this facility, who would you have called when problems arose, when parts were needed, when drawings were missing, etc? No doubt a fundamental reason for EcoElectrica's success over the years is the survivor instincts developed by its can-do O&M team during the early years. Many of these people are still at the facility, several are first-line managers today.

Wilbert De La Paz, manager of mechanical maintenance, reviewed for the editors some issues identified with the plant's large rotating machines over the years, and the solutions implemented—which added significantly to the industry's collective knowledge. The gas turbines presented the biggest challenges simply because EcoElectrica's engines were among the first in the Westinghouse F-class fleet. As De La Paz recalled, these units were ordered in the 1997-1998 timeframe and installed during 1998-1999; he was an OEM employee at the time and a member of the erection team for a short period.

To put EcoElectrica's GT pedigree in perspective, consider that the first Westinghouse F-class machines began commercial operation in May 1993, only a few years before the engines for Puerto Rico were ordered. When the purchase order was signed, there only were about twenty 501Fs in operation or on order, with total fleet operating hours in the neighborhood of 200,000.

Only 19 W501FCs were built, according to Siemens statistics, together operating for about 560,000 hours through December 2011. The 501F in-service fleet at that time numbered 248 units; operating hours totaled nearly 7.6 million. Also of note, only six Fs each had rung up more than 100,000 operating hours, including the two machines in Puerto Rico.

A review of the EcoElectrica engine's specs reveals 16 compressor stages and a 14:1 compression ratio. Normal start as-built was 29.5 min to full load. When the unit was installed, the variable inlet guide vanes were of AISI 616 stainless steel; actuator was pneumatic. Compressor rotor and stator blades were made of AISI 403.

The combustion section was equipped with 16 combustors, two igniters, two UV flame detectors, pressure-atomizing system for liquid fuels and orifice jets for gas (Fig 18). The four-stage turbine section came with IN-738 rotating blades in the first three stages, U-520 in the last; first two vane rows were of ECY-768, last two X-45.

The gas-turbine generators are relatively standard, 60-Hz, hydrogen-cooled units rated 13.8 kV, 205 MVA at 0.85 power factor (174 MW).

Fuels, combustion

EcoElectrica's GTs are unique in the Siemens F fleet, having the capability to operate on LNG, LPG, and distillate oil. The units started on fuel oil and ran on LPG (liquefied petroleum gas, or more simply, propane) exclusively for

20. Fuel gas from the LNG and LPG vaporizers is superheated to about 250F using IP feedwater. The fuel-gas scrubber protects the gas turbine against liquids carryover

about the first five months they were in service because the LNG terminal was not completed until August 2000. In a way this was beneficial, because valuable lessons were learned in how to operate the alternative fuel systems and how to start on oil. The plant is permitted to burn distillate for up to three months in any rolling 12-month period.

Today, the engines run relatively few hours on the back-up fuels: Reliability of the LNG terminal is better than 99.9% and annual availability averages about 99.5%. When the rare upset in terminal operations occurs, operators immediately switch to ultra-low-sulfur (0.04% S) distillate stored onsite (refer back to Fig 1; large tank in foreground).

It takes about two hours to line up the propane "day" tank at the plant site (to the left of the distillate oil tank in Fig 1) and the LPG vaporizers serving each of the engines (Fig 19). As soon as that can be done, fuel is switched from oil to LPG. Onsite LPG inventory is replenished from a

storage tank maintained by ProCaribe, a division of Terminal Acquisition Co at its tank farm approximately three miles from EcoElectrica.

Limiting run time on diesel oil to the minimum required stretches the fuel budget and reduces the potential for fouling in the hot gas path (HGP) and of the SCR (selective catalytic reduction) catalyst. Ultra-low-sulfur distillate is known to degrade over time, faster in warm, high-moisture climates such as that characteristic of southern Puerto Rico. Physical and chemical properties of the stored distillate are closely monitored and upgraded as necessary.

Online fuel transfers are relatively smooth when engine operation is stable and output is about 120 MW, GM Reyes told the editors. In 2011, he said, EcoElectrica operated a total of 411 hours on LPG; more than 20 fuel swaps were involved and there were no material issues.

Feedwater from the HRSG's HP circuit at a nominal 380 psig/300F is used to vaporize propane. Fuel gas supplied from either the propane or LNG vaporizers, depending on which is in service, is superheated in the horizontal heat exchanger shown in Fig 20 using IP feedwater at a nominal 380 psig/250F. Gas exiting that heater passes through a scrubber (vertical vessel to the right of the heater in the photo) on its way to the gas turbines—this to protect against the unlikely carryover of liquids. A chromatograph monitors gas characteristics in real time to assure that the fuel being fed to the turbines is in compliance with OEM specifications.

The original diffusion-flame combustors (DF-42) still serve the gas turbines. Although some DF-42 owners have migrated to dry low-NO_x (DLN) combustors, this is not possible at EcoElectrica because the OEM will not support their use on propane. The plant has had a long-term service agreement in place with the manufacturer since 2008.

NO_x control is by way of IP steam injection and SCR. PSD (Prevention of Significant Deterioration) permit limits are 7 ppm on natural gas and 9 ppm on LPG. Reyes noted that ammonia injection increases significantly when burning LPG. In round numbers, he said, you can expect to use four times as much of the reagent when firing LPG than you would with natural gas.

GT issues, upgrades

With EcoElectrica's engines among the first Westinghouse F-class gas turbines to enter commercial operation, most industry observers would expect these machines to have experienced more problems early in life than a unit going into service today. They did. One indicator: A forced-outage rate of more than 3% during the first two years of operation. But the OEM generally was close by with the support necessary to transition the engines from a prolonged teething period of about three years to the relatively reliable power producers they had become by the time Reyes took over as plant manager in 2004.

21. Drift eliminators supplied with the air-inlet house were ineffective in preventing water intrusion

Over the last eight years or so, the combined cycle has operated reliably in base-load service with daily load-following dispatch—typically achieving an annual service factor above 90% and a capacity factor of about 80%. Improvements introduced before and during the first major inspections (Unit 1 in 2003 and Unit 2 in 2004) get credit for the lion's share of this success.

What follows are notes on some of the specific issues encountered over the years by De La Paz and his mechanical O&M team, as well as solutions/upgrades implemented:

Transition pieces dominated among the early issues. The first TPs were of a single-layer design. A switch to the later double-layer design eliminated problems experienced previously. Transition seals still require periodic maintenance. That is done under contract by a company specializing in such work.

Combustion dynamics were problematic, particularly when burning propane. A combustion dynamics monitoring system (CDMS) installed by Siemens has been beneficial.

Air intake. Plastic drift eliminators installed with the air-inlet house never met expectations (Fig 21). Rainwater got by them, damaged filters, and entered the compressor. In addition, silica migrated through the prefilters and after filters in the two-stage system.

A change in operating procedures helped somewhat. Plant personnel now admit glycol/water coolant to the chiller only after the GTs are at full load. Note that air entering the inlet house first passes through the chiller coils—then, in turn, through the demister, prefilters, and main filters. Condensate collected from the chiller is sent to the cooling-tower basin as makeup.

New air filters and demisters were installed on both GTs in 2012. Munters Corp's (Kista, Sweden) mist elimination solution was selected along with Viledon® F-45 prefilters and MX-98 second-stage air filters from Freudenberg Filtration Technologies KG, Weinheim, Germany. These changes immediately reduced the inlet loss by 0.5 in. H_2O, De La Paz said. He added that thorough check of filter condition and performance would be done as part of the January 2013 planned outage. Current plan is to change out the V-panel prefilters annually, the after filters every other year.

Pneumatic fuel-gas control valves originally installed proved unreliable. About the time Reyes arrived at the plant, Siemens and the EcoElectrica O&M team had decided to replace them with a hydraulically operated/digitally controlled offering from Moog Inc (servo)/Fisher Controls (fuel valve). Starting reliability improved immediately. The small reservoir of hydraulic oil is changed annually to avoid varnish and other oil-related problems.

Vibration monitoring capabilities have improved with a Bently 3500 system. It replaced a Bently 3300. Many other users have done the same.

Generator thermal imbalance, caused by obstructions in cooling passages, dictated replacement of the rotor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(field) in one GT in 2003. It has worked well since. Both generators were fully re-wedged by the OEM during their second major inspections.

Proof of flame. Unreliable UV scanners for flame detection were the source of many unit trips in the first few years of operation. The plant O&M team, working with Siemens engineers, developed a software solution that uses blade-path temperatures to verify flame and significantly improve starting reliability.

Water wash systems supplied with the GTs failed to keep the compressors clean. Inspections of the machines during their respective first majors identified deposits of dirt on and excess detergent within stationary and rotating components. Blades were cleaned only through Row 6, De La Paz said, and there was evidence of leading-edge droplet erosion on some airfoils.

Wash systems were replaced on both units in 2006 with ones supplied by Rochem Technical Services Group. Online cleaning is done every other night using plain water. Weekly, a 5-min detergent wash is initiated, followed by a 10-min rinse cycle. Offline washes are done perhaps three times a year, as the GT operating regimen permits. Compressor efficiency calculations using EtaPRO™ from GP Strategies Corp indicates that the cleaning program is effective and provides economic benefit.

Weld cracking on struts supporting the compressor inlet scroll were found during an inspection suggested by the OEM. The redesigned strut configuration implemented consists of Z-shaped pipes to replace the existing straight struts and pipe flanges bolted to the inlet wall for attachment.

Anti-rotation pin relocation. Diaphragm/blade-ring mod for Rows 7 to 15 of FA-FC compressors was implemented to prevent failure of anti-rotation screws. Relatively simple fix involved changing the location of the anti-rotation screw to the opposite side of the cylinder and diaphragm—this to load the screw in compression instead of tension.

Cracking of Row 2 turbine blades on 501F engines, covered extensively by the editors in articles available online at www.ccj-online.com, was found in both EcoElectrica GTs. The OEM replaced 30 of the 66 R2 blades in Unit 1 and 18 in Unit 2 because of (1) indications emanating from the trailing edge within about an inch of the platform and (2) blade pedigree concerns.

Clearances were increased between the inlet-guide-vane pucks and their respective counterbores to mitigate IGV sticking caused by corrosion.

Cracks in the exhaust manifold are patched as needed; turbine-end expansion joints are replaced during every major.

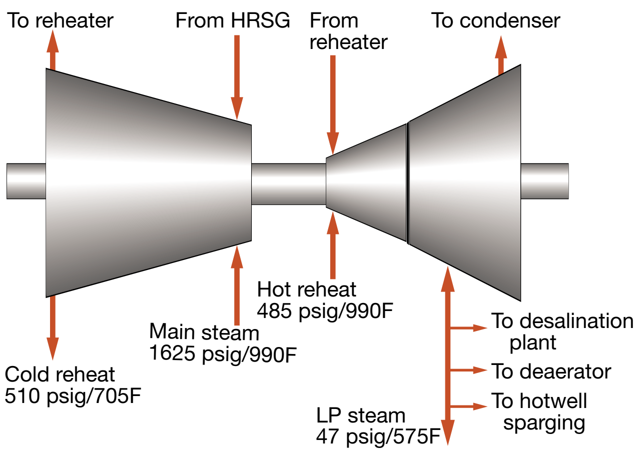
The second major was conducted in 2009 for Unit 1 and in 2010 for Unit 2. These GTs rank second in the 501F fleet in terms of service hours. EcoElectrica arranged a rotor swap for Unit 1, which had accumulated 96,000 equivalent operating hours (EOH) when the second major began. This was close to the 100,000-hr trigger point for the OEM's Class IIB inspection. To access details on what's involved in so-called "lifetime inspections" for gas turbine rotors, go to www.ccj-online.com and use the search function at the top of the page.

The Unit 1 rotor passed its inspection. No significant issues were identified, marriage-coupling surfaces were flat, through-bolts were fine. New compressor blades were installed in-kind. The bottom line: The rotor was "zero-houred" and returned to Puerto Rico to be used in Unit 2 the following year. The Unit 2 rotor, in turn, would be refurbished by the OEM and returned to the pool.

Borescope access ports were installed at Rows 4 and 6 in both compressor casings during their second majors to allow more thorough inspections from outside the machine. Also, new insulation was installed on the GTs before they were returned to service. De La Paz said the Crossby Dewar Inc (Ontario) product is easier to remove and replace than the original insulation and it contributes to better thermal efficiency.

Machining was done during the second majors to address the potential for wear on the outer-diameter hook and hook-fits as found on some 501FCs—particularly at the 9 to 10 o'clock and 3 to 4 o'clock locations (looking in the direction of flow). The motivation: Inner shroud and seal holders had migrated forward in some instances and contacted upstream rotor blades, resulting in liberated material and downstream effects.

Looking ahead to the major inspections in 2015 and 2016, the O&M team already has proposed a series of reliability upgrades. One upgrade planned is a swap-out of the pneumatic actuators supplied with the variable inlet guide vanes with hydraulic actuators.



22. Steam turbine/generator produces about 40% of EcoElectrica's output. Steam conditions incorporated into the sketch below are nominal base-load numbers when burning LNG. Note that the LP steam supply line can flow either way: Steam can either be extracted from the LP cylinder or supplied to it

6. HRSG surface arrangement

Heating surfaces in EcoElectrica's Alstom heat-recovery steam generators are arranged as follows in the direction of gas flow:

- HP superheater
- Reheater
- Duct burner
- HP evaporator
- HP economizer
- LP superheater
- IP superheater
- IP evaporator
- IP economizer
- LP evaporator
- LP economizer

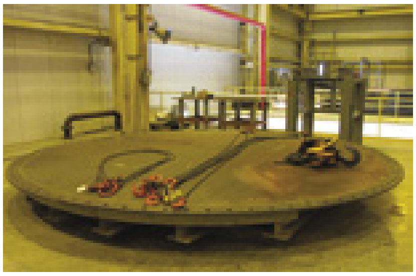
Rankine cycle

There was relatively little discussion on the heat-recovery steam generators during the editors' visit to EcoElectrica suggesting they essentially are meeting expectations. One might expect that given their generally modest design pressures, temperatures, and flows and the plant's conservative base-load operating regimen. The arrangement of heat-transfer surfaces for these triple-pressure HRSGs is presented in Sidebar 6.

When the GTs are firing LNG, 3.575 million lb/hr of exhaust gas at 1137F enters each of the boilers, producing 515,000 lb/hr of HP steam at 1625 psig/990F with duct burners turned off. IP steam flow is nominally 65,000 lb/hr at 350 psig/512F. Gas temperature

23. Two trailer-mounted tanks are used to store anhydrous ammonia for the SCR system while the plant's permanent reagent tanks and supply system are inspected and refurbished. Note the wind sock to aid safety officials in the unlikely event of a leak

24. Main stop and control valve regulates steam flow to the turbine. Generator end is to the right



25. Blank flange isolates the steamer from the condenser during maintenance, enabling simple-cycle operation

26. Expansion joint is removed and blank flange is inserted in its place in less than half a day (right)

at the stack is 207F. Gas-side pressure loss is 13.7 in. H_2O.

Steam leaving the HP superheater goes to the six-stage HP turbine, does work, and exhausts to the reheater (Fig 22). There the temperature of the 510-psig cold reheat steam is increased by about 300 deg F to a nominal 990F. This hot reheat steam drives the single-flow IP/LP turbine section (five stages in each turbine), which exhausts to the condenser at about 2.5 in. Hg abs. All steam-system drains are routed to a blowdown tank in the generation building and its contents are directed to the condenser.

Thermal off-take points in the cycle include the following: IP steam is injected into the GT combustion section for NO_x control, heat from HP feedwater is used for vaporizing LPG, heat from the IP feedwater is used for superheating the fuel gas in service (LNG or LPG), and LP steam, either extracted from the last turbine section or provided by the HRSG, drives the desalination process.

Lube oil system. The hydrogen-cooled 18-kV generator for the steam turbine is rated 252 MVA at 0.85 power factor (214 MW). The generator and turbine share a common lube-oil system underpinned by a 3600-gal carbon-steel reservoir coated with aluminum paint.

Dual-cartridge filters remove particles entrained in the oil large than 5 microns (nominal); oil coolers are of the fin-fan type, heaters of the electric immersion type. Main and auxiliary ac submerged lube-oil pumps, rated 600 gpm at 140 psig, have 125-hp, 460-V, 3-phase motor drivers. The emergency dc pump is rated 530 gpm at 25 psig.

Ammonia system. While the editors were onsite, EcoElectrica was conducting its five-year inspection of the SCR reagent system. A certified third-party company was inspecting the anhydrous ammonia tank serving each unit for metal deterioration. Ammonia lines to the SCR are replaced in parallel with this effort. One challenge associated with this inspection is to remove the anhydrous ammonia in onsite tanks and transfer it to portable tanks (Fig 23), conduct the inspection and replace the ammonia distribution piping, and then transfer the reagent in temporary storage back to the permanent plant tanks.

Steamer overhaul. Also during the editorial visit, preparations were underway for the steam turbine's second major inspection in January 2013. The main steam stop and control valve for the HP turbine is shown in Fig 24. Generator is to the right of the main steam line entering the unit, turbine and condenser to the left.

The blank flange in Fig 25 was ready to install between the LP turbine and condenser at the start of the outage. The expansion joint in Fig 26 would be removed and the blank bolted in place to isolate the condenser from the turbine, thereby enabling operation of both GTs in simple-cycle mode and bypassing steam to the condenser without risk to personnel while the steamer is inspected and refurbished. De La Paz said station personnel had the procedure well in hand and could swap-out the blank plate for the expansion joint in half a day or less—perhaps in as little as eight hours.

Heat rejection system. The two-pass condenser has 18,556 1-in.-diam × 22 BWG B338 (Gr 2) tubes in its main condensing and gas removal sections with an effective length of 30.7 ft and an effective surface area of 149,000 ft^2. Duty is 1.1 billion Btu/hr; average circulating water velocity is 7 ft/sec. Design seawater temperature is 90F. Conventional steam-jet air ejectors are used to maintain condenser vacuum.

The Caribbean Sea (Guayanilla Bay) is the source of cooling water for the Rankine cycle; its temperature can vary from 74F to 92F depending on the season. Heat absorbed by circulating water in the condenser, and by cooling water in the CCW system and desalination plant, is rejected in an eight-cell, induced-draft tower, built by Belgium's Hamon & Cie. Its basin and frame are made of concrete; fan decks, stacks and siding of fire-retardant FRP with stainless-steel hardware. Fill is 15-mil Hamon AFNCS.

The tower typically operates at from

27. Two-cell helper tower cools blowdown to less than 90F on hot summer days

28. Three 50% circ-water pumps deliver water from the cooling tower basin to the condenser

1.2 to 1.3 cycles of concentration to restrict total dissolved solids in the blowdown stream to 50,000 ppm. Discharge to the sea is via three diffusers located 30 ft below the water surface near the LNG pier. The plant's operating permit limits the temperature of return water to 90F. In summer, use of a two-cell booster tower sometimes is required to cool blowdown prior to its discharge (Fig 27).

Water required by the condenser, 142,000 gpm, is delivered by two of three 50% circ pumps taking suction from the tower basin (Fig 28). These pumps also provide 8000 gpm to the closed cooling water system and 6000 gpm to the desalination plant. The tower is designed to cool the 156,000-gpm return flow from100F to 86F at a wet-bulb temperature of 73F.

Performance improvement. The additional LNG vaporization capacity installed in 2012 allows the glycol heaters serving the new vaporizers to reduce the seawater temperature for all plant services—condenser circulating water, CCW, and desalination plant (Sidebar 7)—by 10 deg F. This cycle enhancement has enabled better and more predicable thermal performance. The heat-rate improvement for the condenser alone is approximately 35 Btu/kWh when 77 million scf/day of LNG is vaporized, according to Dr Jose Rullan, PE, project engineer.

As mentioned earlier, the boiler blowdown tank empties into the cooling-tower basin after filtration to remove any solids present. The clean stream from the oily water separator also discharges to the basin (Fig 29). The physical and chemical properties of basin water are monitored twice monthly for a period of 24 hours; tests capable of detecting the presence of hexavalent chromium are conducted weekly. A diver removes dirt and deposits from the basin twice annually; quarterly, all catch basins and the oily water separator are cleaned.

29. Oily water separator's clean stream is sent to the basin of the cooling tower in view at left

Cooling-tower fans, supplied by Netherlands-based Howden Group Ltd, are 30 ft in diameter and have six fiber-reinforced polyester blades with leading-edge protection. High-efficiency, severe-duty, motors with windings designed for the tropical environment turn the fans at 127 rpm through right-angle double-reduction gears. Japan's Toshiba Corp supplied the 250-hp, 460-V, 1800-rpm motors; Texas-based Amarillo Gear Co LLC, the gears. Vibration and low-oil-level switches and protection against reverse rotation were included in the drive package.

During normal combined-cycle operation, two of the three 50% condensate pumps take suction from the 13,350-gal condenser hotwell and push nominal 110F cycle water through air-ejector condensers, gland condenser, and rotor air coolers (RACs) before entering the plate-and-frame preheaters.

The RACs boost condensate temperature by about 35 deg F to a nominal 150F ahead of the preheaters. The latter use LP drum water to add another 30 to 40 deg F before condensate enters the LP economizers at about 175F to 190F. Note that water samples for analysis are withdrawn downstream of the condensate pump and cycle chemistry is adjusted with chemical injections just ahead of the air-ejector condensers.

Electrical, I&C

Gaspar Bibiloni, PE, has a great deal of responsibility at EcoElectrica. He manages the Electrical, I&C, and DCS Maintenance Dept (E/I Dept) as well as the Engineering Dept—the two groups having a total employee count second only to Adolfo Antompietri's Operations Dept.

The E/I Dept is responsible for the predictive (PdM), preventive (PM), and corrective (CM) maintenance of all electrical equipment and I&C devices—including the DCS, CEMS, and PLC controllers—in the powerplant, water treatment area, and LNG terminal. This encompasses some 3100 instruments and 1150 pieces of electrical equipment. Electricians are certified in thermography, ultrasound, and substation maintenance, I&C techs in DCS hardware, PLCs, analytic instrumentation, and CEMS. Training is ongoing in these areas as well as others.

Not all work is done by station staff. EcoElectrica has maintenance and inspection contracts with several OEMs and experts for specialized equipment and/or crafts. Examples: Emerson Process Management for the DCS, Rockwell Automation Inc for PLCs, Cummins Inc for the emergency diesel/generators. In addition,

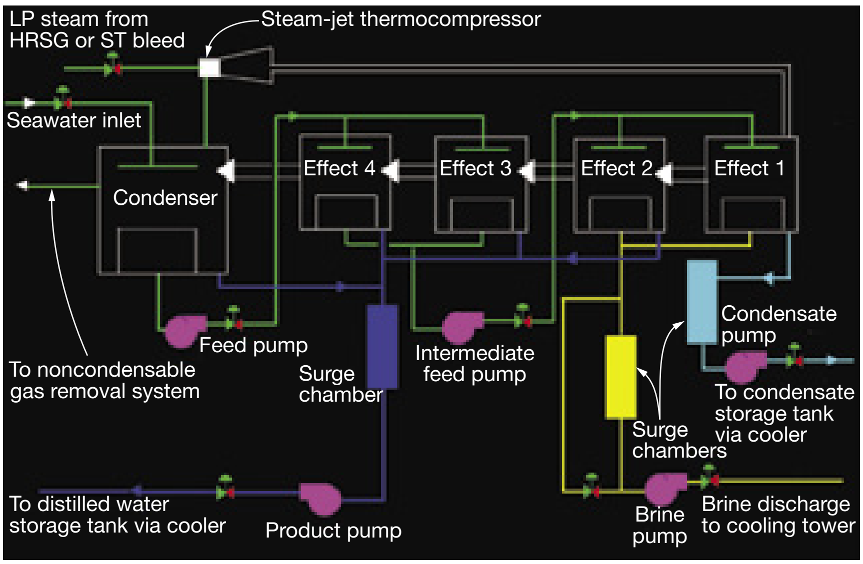
7. Desalination system provides potable water, boiler makeup for onsite, offsite use

EcoElectrica's two multi-effect seawater distillation plants, each rated a nominal million gallons per day, are critical to the facility's operation (Fig A). Product water from the four-effect evaporators, supplied by Israel-based IDE Technologies Ltd, is used to produce steam-cycle makeup for both EcoElectrica and Prepa's Costa Sur Power Plant as well as potable water for both onsite use and for send-out to the Puerto Rico Aqueduct and Sewer Authority (Prasa).

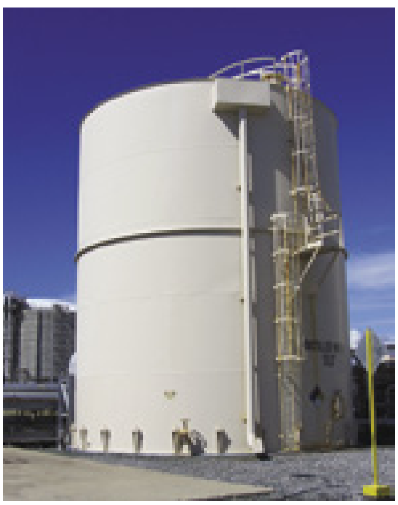
Energy for distillation is provided by low-pressure steam (nominally 30 psig) from the heat-recovery steam generator or from the LP turbine bleed (refer to Figs D and E in the main article). The LP steam powers a steam-jet thermocompressor which enables efficient evaporation at low temperatures.

Steam from the thermocompressor enters the first effect's horizontal tube bundle, transferring heat to seawater cascading down the outside of the tubes (Fig B). The condensate that forms in the tubes flows via a cooler to the condensate storage tank at about 100F. From there it passes through a mixed-bed polisher and is retained in the demin storage tank until needed for cycle makeup. The polisher can process about 4 million gal of condensate before the mixed bed must be

A. Four-effect desalination units at EcoElectrica each produce a nominal million gal per day of distilled water



B. Brine increases in temperature as it flows from the fourth to the first effect; effect shell pressure decreases in the opposite direction



C. Three-quarters of the inventory of the 400,000-gal distilled water tank is reserved for fire protection

D. Minerals are added to distilled water to make it suitable for human consumption regenerated, which is done onsite.

Vapor formed on the shell side of the first effect flows through the tube bundle of the second effect, which operates at a lower pressure than the first effect. The heat transferred to cascading seawater in the second effect creates the vapor used in the third effect's bundle, and so on. Distilled (product) water created by the condensation of vapor in the second, third, and fourth effects, as well as in the condenser, is cooled to about 95F, and stored in a 400,000-gal tank (Fig C). The distillate product contains less than 5 ppm TDS (total dissolved solids).

Three-quarters of the distilled-water tank's capacity is dedicated to fire-water reserve. A portion of the remainder is sent to the condensate storage tank, as required, and to Prepa. The balance flows through a remineralization system (Fig D), thereby making the distilled water acceptable for human consumption. Water not required for the plant's potable and service-water systems is sold to Prasa (Fig E).

Looking at Fig B, note that incoming seawater (about 88F in summer, 72F in winter) flows through the condenser first. It operates at the lowest pressure in the train of five heat exchangers. Temperature of the brine, and its salinity, increase as the seawater flows from the fourth to first effects. Brine is discharged to the cooling tower at about 140F. Of interest to generation planners investigating sites with ocean access, EcoElectrica's original seawater piping was stainless steel, but deterioration forced its replacement with FRP.

E. Potable water in excess of plant needs is sold to the Puerto Rico Aqueduct and Sewer Authority

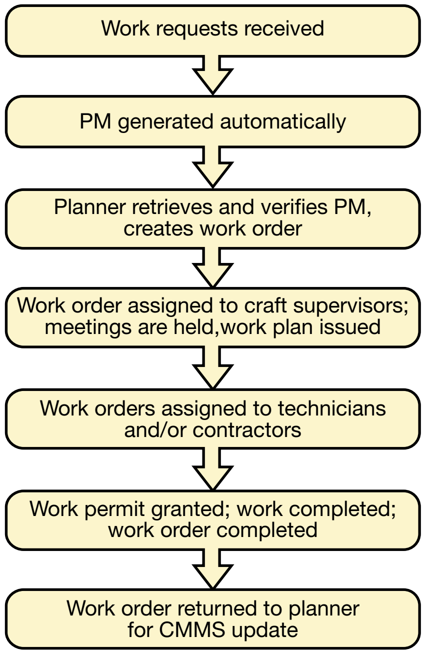
the plant has contracts with safety and test experts, and laboratories, for specialized analyses and/or certifications. Examples include lift equipment certifications, dissolved-gas analysis for transformer oil, and thermography.

Plant personnel and contract experts are supported by continuous monitoring on important equipment to warn of potential issues. Some examples are listed below:

- Online monitoring of transformer oil for dissolved gas and moisture (Hydran, General Electric Co).
- Flux probes to detect shorted turns in generator fields (Generatortech Inc).
- Partial discharge detector for advance warning of insulation problems in unit substation dry-type power transformers (InsulGard, Eaton Corp).
- Battery diagnostic system tracks cell voltage, overall string voltage, current, temperature, and internal resistance. Automatic periodic tests verify battery integrity; alarms on out-of-tolerance condition (MPM-100, Alber).
- Generator condition monitor detects pyrolytic and hotspot activity which can lead to overheating and failure (GCM-X, Environment One Corp).
- Transient recorder/power meter with power-quality and communications capability, installed on all generators and the 230-kV transmission line (Nexus® 1500, Electro Industries/GaugeTech).
- Transient recorder to analyze utility and facility transient disturbances, power swings, frequency events, etc (IDM, Qualitrol Corp).
- Software to monitor/collect data on metering events, protective relay settings, etc, for analysis (acSELerator®, Schweitzer Engineering Laboratories).
- Motor/asset management tool integrates testing, diagnostics, inventory control, scheduling, and cost containment. It monitors potential fault zones and notifies on alarm conditions (MCEmax™, PdMA Corp).

One of the reasons for developing expertise in the monitoring of electrical equipment and circuits is that there are many grid disruptions on the island and it's necessary for EcoElectrica to determine quickly if the problem is in the plant or on the electrical system at large.

To keep up with developments in technology, plant safety practices, regulations, and best practices, GM Reyes and Bibiloni encourage key personnel to participate proactively as members of the International Society of Automation (ISA), National Society of Professional Engineers (NSPE), National Electrical Testing Assn (NETA), and the College of Engineers and Land Surveyors of Puerto Rico (CIAPR), as well as in the iMaint, Ovation, and 501F Users Groups.



30. Work planning, scheduling process flow

The plant also subscribes to standards of the National Fire Protection Assn (NFPA), National Electrical Code (NEC), and the IEEE.

Critical to this department's operation is the iMaint computerized maintenance management system (CMMS), developed and supported by DPSI, Greenville, NC. It generates work orders, schedules preventive maintenance, maintains parts inventory, tracks costs and budgets, facilitates reporting and analysis, etc. The plant's work planning and scheduling process is summarized in Fig 30.

Bibiloni began by explaining EcoElectrica's work planning and scheduling processes. Work orders, he said, are the result of work requests made by operations supervisors and other departments plus scheduled PM. Planning is very regimented and conducted/adjusted on a week-ahead basis, day ahead, and current.

Specifically, maintenance supervisors, coordinators, managers, and the health and safety (H&S) coordinator discuss week-ahead plans every Thursday at 1030. Maintenance supervisors, shift supervisor, and planner gather at the planner's office each afternoon at 1530 to review plans for the coming day. Day's plans are reviewed at the daily operations meeting at 0900; it is open to O&M managers, supervisors, and coordinators, and financial personnel.

Ovation™ migration. The biggest

31. Main power transformer (18-230 kV) rated 205 MVA serves GT 1

32. Station service transformer for GT 1 (18-4.16 kV) rated 42 MVA has three windings with two secondary coils. Main power transformer in Fig 31 is to right

controls project in EcoElectrica's relatively brief history was its migration from the as-installed WDPF (Westinghouse Distributed Processing Family) to Emerson's Ovation during the 2008 plant outage (original I/O was retained). Only the Toshiba steam turbine/generator did not have WDPF controls.

Cochran

Process Control Solutions LLC (PCS), Hattiesburg, Miss, was hired by EcoElectrica as the customer's engineer to provide control-system engineering for the project—including total plant as-built review, factory acceptance testing, onsite operator training, and commissioning support.

Mitch Cochran, founder of PCS, was no newcomer to EcoElectrica. He had been involved with the project since before its commissioning in March 2000 as a Siemens Westinghouse Power Corp employee. Cochran had done some of the original programming work for the gas turbines, HRSGs, and balance of plant.

His first significant controls project at the Puerto Rican facility was in 2005 when Cochran performed a "Mem-Free" procedure on GT drops to free up DPU memory capacity, thereby allowing implementation of several gas-turbine mods by Siemens. At that time he conducted an as-built review of GT controls for Siemens and upgraded the WDPF controls to improve plant reliability. Cochran has presented several times at 501D5-D5A User meetings on how to free up DPU memory capacity. Use the search function at www.ccj-online.com to learn more.

A year later, Cochran conducted an as-built review of HRSG/BOP drops for EcoElectrica, as well as a WDPF assessment, in preparation for the Ovation migration. While involved in the control-system retrofit, he added controls for a third LNG sendout pump. In 2011 and 2012 Cochran was back onsite to implement controls modes in support of the LNG expansion project described earlier. He supported installation and commissioning of the expansion project and added an interface for the export fuel-gas metering skid. During the upcoming 2013 outage Cochran will be back at the plant—this time to implement HRSG attemperator drain-valve mods and GT hydraulic IGV actuator mods.

Electrical system. Three generators produce power for sale and internal use—two are driven by the gas turbines and rated 205 MVA each at 0.85 pf, one by the steam turbine and rated 252 MVA at 0.85 pf. Emergency power at 4160 V can be provided throughout the facility by a 1250-kW Cummins diesel/generator and to the administration building and warehouse by a 150-kW Cummins diesel/generator. For the combined cycle to be black-start capable, 10 MW of emergency generation would be required.

EcoElectrica delivers power at 230 kV to the island grid via the IPP's 2-mi tie line to the Costa Sur switchyard. The switchyard at the combined-cycle plant is equipped with four ABB SF_6 gas circuit breakers arranged in a ring-bus configuration. The main transformers for the gas and steam turbines step up the voltage from 18 to 230 kV (Fig 31). Two station service transformers, each rated 42 MVA, step down the voltage from 18 kV to 4.16 kV. An additional step down to 480 V provides power to a dozen motor control centers throughout the facility.

Four battery banks and chargers provide emergency power at 125 Vdc to the steam turbine building, GT 1 and 2 electrical packages, and the 230-kV switchyard. Battery banks for the emergency generators and diesel-driven fire pump are 48 Vdc.

A recent initiative was the upgrading of protective systems. Specifically, relays for major equipment and the main 4.16-kV switchgear were replaced with relays from Schweitzer Engineering Laboratories. System provides protection, data acquisition, recording of disturbances, and other benefits.

Bibiloni next reviewed with the editors some electrical system maintenance activities beyond the normal PM, including the following:

- Annual infrared surveys of the 230-kV tie line.
- Periodic electromagnetic interference (EMI) surveys by Doble Engineering of all generators, isophase bus ducts, and some major motors.
- Annual frequency response analysis (FRA) of all generators and transformers.
- Verify integrity of cathodic protection systems. An outside grounding expert does this.
- Inspection by divers of sacrificial anodes on LNG pier piles.

33. Guayanilla Bay extends out into the Caribbean Sea offering a panorama of a majestic tropical land. Storm-water retention pond is adjacent to desalination units

34. Plumes identify the three diffusers near the LNG dock where cooling water is discharged back to the bay 30 ft below the surface

- Manage and support the Health and Safety Dept in all electrical-safety activities—including the inspection of power cabinets, electrical integrity testing of power cords and tools, ground integrity testing, and testing of high-voltage gloves, rescue hooks, sleeves, and sticks.

Environment

Environmental management at many generating facilities powered by gas turbines equates to meeting permit limits for air and water emissions, cleaning up inadvertent spills of fluids, and preventing uncontrolled releases of potentially harmful gases such as ammonia and sulfur hexafluoride. Nothing wrong with that in most places.

But not along the southern coast of Puerto Rico, a sun-bathed resort area (Fig 33). Preservation of this ecologi-

8. EcoElectrica, UPR collaborate on marine environmental science

EcoElectrica's operations depend significantly on coastal water resources. Since its startup in 2000, the plant has established a comprehensive biological monitoring program to assess the condition of marine ecosystems and the quality of the surrounding water bodies.

In 2011, EcoElectrica began a collaborative research program with the Univ of Puerto Rico's (UPR) Dept of Marine Sciences (DMS) at the Mayaguez Campus. In that collaboration, I have served as principal investigator on behalf of the university, where I have worked for the past 17 of my 25 years as a marine scientist.

Among other benefits, the collaboration has offered DMS graduate students a unique opportunity to acquire professional experience while applying their knowledge in a "living laboratory." Thus, EcoElectrica is supportive of the university's goal of providing hands-on experience to graduate students in marine sciences at various stages of their studies. Since 2011, eleven students have been incorporated into the program, participating in all phases of sampling and analysis.

Graduate students are investigating the dynamics of entrainment and impingement of marine species at the facility's seawater intake; water currents and sediment composition; water-quality indicators; and the influence of the facility's process water discharge over corals, fishes, shellfish, seagrass habitats, and other species.

This diversity of topics provides an extraordinary opportunity for students to integrate new knowledge into existing information and develop a better understanding of the complex marine ecosystem dynamics surrounding EcoElectrica. The results of these studies have facilitated the plant's compliance with its environmental goals and regulatory requirements as well as with the evaluation of ongoing mitigation projects.

In 2011, EcoElectrica donated to the DMS approximately $130,000 in state-of-the-art instrumentation essential to the research and assessment of phytoplankton communities in "La Parguera," one of the three bioluminescent bays in Puerto Rico. This equipment provided the leverage necessary for obtaining an important fellowship to further the examination of bioluminescent organisms and their relationships with coastal conditions.

The bioluminescent bay at La Parguera is a national treasure and known worldwide. By studying its dynamics, the community at large will have a better understanding of how this delicate ecosystem works and what local residents, tourists, and fishermen, among others, can do to be more responsible when it comes to enjoying its many enchantments.

The collaboration between DMS and EcoElectrica has been extremely successful; the goals established by the plant have been comprehensively met—and even surpassed. At the same time, the university has received the means to support its students with work experiences and access to equipment and materials that otherwise would not have been available to them. This may help students in the development of new ideas that may result into tangible products for the present and future.

I feel great satisfaction in having the opportunity to spearhead the efforts on the academic side. The experience has been of incredible personal and professional growth, not only for the students but also for myself. EcoElectrica's management has been unconditionally supportive to the program and has attended to all the necessities that have emerged in its implementation. My commitment is to keep strengthening the relationship every year, and with the support of the students and our EcoElectrica partners, take it to the next level.

Dr Ernesto Otero Morales
Principal Investigator
Dept of Marine Sciences
Univ of Puerto Rico, Mayaguez Campus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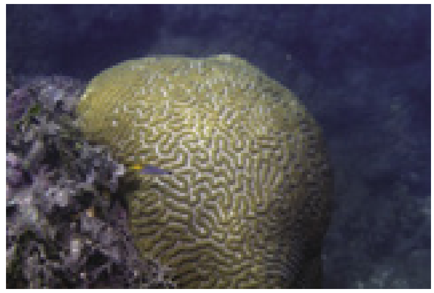

35. Tropical sea life and birds abound in EcoElectrica's "back yard." You can watch dolphins and manatees swim in Guayanilla Bay from the LNG dock, follow four dozen or so species of birds in onsite ponds, and dive into the bay from the plant's biological monitoring craft and find many types of coral

cally sensitive tropical environment is a top priority among EcoElectrica's owners and employees—most of the latter living in the immediate area, some for their entire lives. Guidance for the plant's environmental program is provided by its ISO 14001 certification. In case you're not familiar with this global standard, it is a management tool enabling an organization of any size or type, and in any location, to achieve the following:

- Identify and control the environmental impact of its activities, products, and services.
- Improve continually its environmental performance.
- Implement a systematic approach to setting environmental objectives, to achieving these objectives, and to demonstrating that they have been achieved.
- Ensure legal compliance.

The air pollutant of primary concern for combustion turbines burning natural gas is NO_x. At EcoElectrica, emissions are controlled in two steps. The first is to minimize NO_x production by quenching combustion-zone temperature with steam. Final step, selective catalytic reduction (SCR), uses a catalyst to react injected ammonia to chemically reduce most of the remaining NO_x. Permit limits are 7 ppm when burning natural gas, 9 ppm when burning propane.

Water is withdrawn from the Caribbean Sea in Guayanilla Bay for cooling the main condenser and plant auxiliaries, for vaporizing LNG, and for processing by the demineralizers into distilled water. An induced-draft, wet cooling tower and a monitoring station assure that water returned to the bay is at a maximum temperature of 90F, contains less than 50,000 ppm of total dissolved solids, and meets chemical discharge criteria (Fig 34). Physical and chemical properties of the discharges are monitored twice monthly for a period of 24 hours.

Releases of water from the stormwater retention pond seen in Fig 33 are tightly controlled. Most is not discharged to the bay; it evaporates. Physical and chemical properties of the pond water are checked quarterly.

Damaris Negron-Alvarez, environmental compliance manager, told the editors that the plant has implemented since its beginning innovative programs focused on the conservation and protection of endangered species and sensitive ecosystem that coexist with its operations in the Tallaboa and Guayanilla Bays.

Plant operators and maintenance technicians are trained as ISO and OHSAS internal auditors and really make a difference in controlling the processes and work at the facility to maintain the compliance culture and environmental stewardship that distinguish EcoElectrica from others.

The facility's NPDES permit requires ongoing biological monitoring of Guayanilla Bay—a process that began 14 years ago. EcoElectrica has been an uncompromising protector of the environment from the beginning. Over the 14 years, no significant impacts have been recorded. This has been confirmed by professionals and graduate students associated with the Univ of Puerto Rico's Dept of Marine Sciences at the Mayaguez Campus (Sidebar 8).

To illustrate how serious and thorough the environmental protection program is, consider that before construction of the LNG pier began, coral and sea grass in the area was moved to other parts of the bay for safe keeping. After the pier was complete, these species were transplanted successfully from where they were removed.

Negron-Alvarez also mentioned the following:

- Manatees and turtles are protected species and their populations are monitored on an ongoing basis (Fig 35). In 2011, EcoElectrica donated $75,000 for the construction of a manatee study center at the Bayamon Campus of Interamerican Univ. During the 2012 survey period, 70 manatees were observed. Surveys of marine turtles are conducted by graduate students in biology from the Rio Piedras Campus of UPR. Fifteen nests were identified in 2010.
- LNG tankers must have "spotters" to assure that the ships will not collide with manatees, turtles, dolphins, etc.
- Contractors receive detailed instruction on environmental sensitivities.
- EcoElectrica maintains more than 60 environmental permits. Jurisdiction among the Federal Energy Regulatory Commission, Dept of Transportation, and local authorities often overlap, making compliance challenging at times.
- Expansion of the LNG facilities in 2011-2012 added 30 environmental requirements and required the services of a third-party inspector for about six months to assure compliance.
- More than 50 species of waterfowl and other birds have been identified with the ponds over the years—most preferring the mitigation pond. Interestingly, some species always seem to return to a given pond.

People

In power generation, like other businesses sharing a common technology with their competitors, people are the differentiators between a "world-class" organization and one that's merely "ordinary." At combined-cycle plants, talented and motivated employees might well make a bigger difference than at other types generating facilities simply because the permanent staffs are so small—typically one employee for every 30 MW of nameplate capability. An army can tolerate a goldbricker, a Swat team cannot.

This final section of the EcoElectrica report focuses on the plant's hiring, training, and employee retention practices, and safety programs. No nuts and bolts here, but a quick read might offer some "pearls" on how to reduce turnover and build a stronger team at your facility. To be fair, much of EcoElectrica's success probably can be attributed to the continuity of its ownership and management, mission, and location. More specifically:

- GDF Suez's acquisition of International Power plc aside, plant ownership has not changed in a decade. One reason for this, perhaps, is that the three owners are in the energy business and they understand the value of EcoElectrica—a crown jewel, in a manner of speaking.

  By contrast, many combined cycles and peaking gas turbines in the US are owned by financial interests with little or no professional appreciation of their asset base; they buy and sell powerplants much like they do hotels and pizza parlors.
- General Manager Reyes has managed operations since 2004 and several of his first-line managers have been associated with the plant for almost as long, longer in some cases. Spend a couple of days with Reyes and you'll find his hand is always on the pulse of the plant.
- The multi-purpose facility is woven into the fabric of Puerto Rico. EcoElectrica's mission to meet customer expectations in the supply of electricity, gas, and water while protecting the environment cannot be compromised. Workforce pride is at stake here: About 90% of the employees live within a 30-min drive of the plant. Their homes rely on electricity and, in some cases, drinking water from EcoElectrica; plus, they and their families swim and fish in the same waters the plant depends on for cooling. One might consider the plant and community as having a symbiotic relationship.

Operations

Operations Manager Adolfo Antompietri has a team of 25 operators and five supervisors. Five operators are needed to run the entire facility—including the combined cycle, demineralizers, and LNG regasification plant. Operations personnel may be certified in one or more of the following positions: powerplant outside operator, powerplant DCS, LNG outside operator, LNG DCS, water plant outside operator, and performance technician—the last a relatively new certification, put into effect in 2008. About 85% of the plant is instrumented in a manner that permits operation via the DCS. Remainder of the equipment and systems are controlled by the outside operators.

Antompietri, who hired on as an operator before commissioning, stressed the need for careful review of candidates for employment. EcoElectrica has relatively few openings for operators in any given year—no one gets bored at this plant—so managers can be particularly selective. The successful candidate will have to understand basic powerplant processes and have some operational experience either at a generating facility, refinery, pharmaceutical plant, etc.

Resumes from industrial mechanics, electricians, and I/E techs get top priority. Antompietri said he'll select about 10 resumes for one open position from a pile of a couple of hundred. Those people will take a demanding written test that requires the candidates to solve complex physical problems. The top performers are invited in for an interview (by a single manager or a panel of operations team members). The finalists are then ranked and the top scorer receives an offer.

The first assignment for an employee in Antompietri's department is either as an outside powerplant, LNG, or water plant operator on the day shift, working alongside team members qualified for that position. Having the new person work days enables them to learn from operators on all five shifts. Depending on the employee's background, an appropriate training program is developed.

Typically, it begins with GP Strategies Corp's (formerly known as General Physics Corp) GPiLearn™ lessons and one-on-one training by supervisors on standard operating procedures and system design details. The latter is facilitated by use of P&IDs (piping and instrumentation diagrams) accessible to employees on demand.

After two to three weeks of classroom sessions, coupled with the requisite tracing of lines for key systems, the new hire is ready for day shifts in the field. It takes the average employee three or four months of classroom and hands-on daytime training before he or she is ready to transition to a shift team. After nine months to a year of shift work, the newest member of the team generally is certified as a qualified operator in the first assigned position.

Next step on the ladder of success is to qualify for one of the remaining operator positions, with a raise for each certification achieved. It

36. Car seals prevent the inadvertent opening or closing of a valve

takes about four years to qualify for the three outside positions. Operator Pascual Ortiz, one of the persons in the control room during the editors' visit, is qualified in all six operator positions; plus he's the union leader for the operators. EcoElectrica has some unionized employees, some non-union.

DCS training takes about a year, then you have to work in the control room for a year before receiving the first "inside" certification. It takes eight to nine years for a highly motivated employee, like Ortiz, to achieve all six certifications.

The performance technician position is challenging and very rewarding. The latter refers to the good feeling you get when an audit finds Btus escaping the process and the leak path is blocked. GP Strategies' EtaPRO™ performance and condition monitoring system is a big help in this regard.

The performance technician also is responsible for the plant's car-seal and lock-seal program. Car seals, like the one shown in Fig 36, prevent the inadvertent opening or closing of a valve. Lock seals are step up in safety hierarchy; a physical lock must be opened with a key to change the position of the valve.

This program, a federal requirement for the LNG terminal, has been expanded to the powerplant because of its obvious safety benefits. Another positive step taken during the expansion of the regasification system was to put bar codes on valves so roving operators can retrieve all necessary O&M information on their digital devices.

Operations support is provided by an electronic toolkit that includes the following systems:

- WIN_TS™ diagnostic system, a Siemens AG product, gathers operational data on the gas turbines from the Ovation DCS via a dedicated interface that enables real-time transfer of process digital and analog point values with 1-sec resolution. The OEM accesses EcoElectrica's WIN_TS servers daily, after midnight, to batch-transfer data compiled the previous day to the Siemens Power Diagnostic Center. There engineers use diagnostic tools to correlate data and analyze trends with the help of expert algorithms. Plant management is informed by email of significant deviations in key parameters and provided an assessment of operational and hardware risks associated with continued operation in the same manner.
- EtaPRO is EcoElectrica's solution of choice for performance condition monitoring. It interfaces with the Ovation DCS, water plant PLCs, and online fuel analyzers. EtaPRO can display, trend, and report automatically, information needed by different plant users—from the control-room operators to the O&M management team.
- ControlWave®, an Emerson product, provides the management team read-only remote access to the Ovation DCS displays, as well as to process data, via secure link. This enables the technical staff to support the operations team from outside the plant boundaries, thereby expediting resolution of system upsets and, in the extreme, minimizing the restoration time from a forced outage.

One final note on operations: The grid controls EcoElectric's operation between 290 and 480 MW. Above that, duct burners are required and the plant operators ignite them and take control.

RCA. Antompietri also leads the plant's forced-outage investigation team to determine the root cause. He is the one constant on the four- or five-person team, convened to analyze anything that affects dispatch and/or availability and impacts operations. Goal is to complete the root cause analysis and provide mitigation recommendations within six months. Necessary changes to hardware, software, and/or procedures are implemented during the next planned outage. If the RCA is not conclusive, further investigation is done during the ensuing outage.

HR programs

No business unit wants to loose good employees. EcoElectric is proactive in this regard, having designed its human resources programs to *retain* employees. This means going beyond the traditional healthcare plans, IRA offerings, life insurance, vacation, nondiscriminatory job postings, etc, that have become "table stakes" in the HR field.

Damaris Rivera, manager of human resources, and GM Reyes walked the editors through some of the elements of the plant's program to strengthen interpersonal relationships among employees, provide a better working environment, contribute to wellness, promote advanced education, and develop closer ties to the community. The plan must be working: A third-party surveyor interviewed employees and found 87% gave EcoElectrica a high satisfaction rating. Here are some highlights of the program managed by Rivera:

- Cooperative group lunches Tuesday and Thursday (company pays two-thirds, employees one-third) have been especially beneficial for building interpersonal relationships and promoting team-building, she said. In addition, shift supervisors are given a modest quarterly allocation for dinners with employees to achieve the same objectives.
- Employee wellness: (1) Two graduate students from the Univ of Puerto Rico (UPR) conduct a physical education/exercise program from 1600 to 1700, and again from 1700 to 1800, four days a week. About 50 employees participate on a regular basis. (2) A nutritionist complements the exercise program by weighing employees, monitoring their health, and offering dietary suggestions. Weight loss plant-wide was well into the triple digits during 2012. (3) An annual field day offers "fun" competitions in calisthenics, street skiing, and other competitive contests. (4) No employee or contractor is allowed to work more than six days in any seven-day period.
- Scholarships: (1) EcoElectrica pays 90% of the tuition for college courses if the employee achieves a grade of at least a "B." Several employees earned their Master's degrees this way. (2) Scholarships for employee children attending college are given in the amount of $1000 per annum for the first child; $500 per annum for the second.
- A co-op program with UPR's Mayaguez Engineering Campus has benefitted 35 students to date. One semester is spent working at EcoElectrica after completing three years of college courses. Two students are selected for each semester and assigned to different departments. Thus far, two co-op students have been hired by the plant: One is now a project manager in the engineering department. The other, Kanyra Padilla, a professional electrical engineer, supervises the I/E techs and is an excellent model of EcoElectrica values.

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37. Yamaris Alancastro Miranda, EcoElectrica's social responsibility manager, presents scholarships to Guayanilla students as the school's principal looks on

38. Five of 15 EcoElectrica employees to attend LNG firefighting school during 2012: Dr Jose Rullan, PE, project engineer; Abimaleck Feliciano, mechanical maintenance supervisor; Frankie Alvarado, warehouse supervisor; Damaris Negron-Alvarez, manager of environmental compliance; and Pascual Ortiz, plant operator and union leader (left to right)

- Community support: (1) Scholarships are given annually to 40 students from local high schools (Fig 37). (2) Learning materials are provided to two-dozen schools in the area. (3) Sponsorships support science fairs. (4) Contributions are made to local community and civic organizations. (5) Three Kings Dream (Sueno de Tres Reyes) is a gift—presented on the Christian feast of the Epiphany, January 6—to a needy child in the community with an illness or disability. Employees raise money, matched by the company, and present the gift. One year the gift was an electric wheelchair; another, it was special furniture for the child's home to accommodate medical needs.

Safety

Employee and contractor health and safety at EcoElectrica are managed by Pedro Martinez, who is supported by Luis Cruz. Both H&S professions are ideally qualified for the work they do and have complementary backgrounds. Martinez has a Bachelor of Science degree in biology and a Master's in occupational health from UPR; Cruz has a Bachelor of Science degree and hands-on experience in emergency response as a US Coast Guard reservist; plus, he's a certified plant operator.

One of Martinez's responsibilities is to meet periodically with the leaders of local first-responder agencies to better understand their capabilities and limitations and to familiarize first-responder teams (firefighters, police, EMT, etc) with the plant and its procedures to assure peak effectiveness if needed. Responsibilities are shared: For example, local agencies lead on firefighting, hazardous materials, and explosives; the plant is the lead on LNG response because EcoElectrica's personnel are most familiar with the idiosyncrasies of the cryogenic fluid.

To illustrate how closely EcoElectrica works with local agencies, consider the following:

- The plant supports the training of local firefighters on how to deal with an LNG leak. In 2012, for example, 15 EcoElectrica employees (Fig 38) and eight local firefighters attended a special fire academy in Massachusetts—all at the plant's expense.
- When it comes to confined-space rescue training, it's the firefighters who train plant personnel. One take-away from this activity for employees is that they better understand the limitations of first-responders.
- The police instruct plant personnel on how to deal with bomb threats and conduct explosion training.

Martinez also participates in the activities of several local groups that address safety/security/environmental concerns and encourage participation by local industry. These include the following:

- Area Maritime Security Committee.
- South Harbor Safety Committee meets quarterly, generally with participation by important federal and local government agencies—such as US Customs and Border Protection and the FBI. Information shared includes best practices and lessons learned.
- Industrial Sector Committee and the Community Awareness Emergency Response Committee meet monthly to share information on hazardous materials, training, emergencies addressed, response plans, etc.

Drills to practice response to such emergencies as fire, spill, tsunami, earthquake (EcoElectrica is in a seismically active area), are an important aspect of normal plant oper-

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39. Vapor fence corrals LNG in the terminal area in the unlikely event of a leak

ations. Quarterly, separate full-scale environmental and safety exercises are conducted to test the entire plant and its systems. During these exercises, in which the operations supervisor is the incident commander, the entire plant is evacuated—except for the fully equipped employees assigned to deal with the emergency simulated. Personnel are rated on response.

A tsunami drill is conducted annually in March/April, sponsored by the National Weather Service. Everyone leaves except the operations supervisor; he moves to the highest building in the plant, which has supplies for several days.

An earthquake drill—called "Shakeout"—is sponsored by the Federal Emergency Management Agency (FEMA) and the National Oceanic and Atmospheric Administration (NOAA) and conducted each October 18 at 1018.

In addition, the plant conducts a hurricane walk-down in June as part of its emergency drills. Everything that could be liberated or moved by a high wind and/or high rain is secured. The power block is designed to withstand a Category 3 storm, the LNG terminal a Category 5 storm. If a Category 4 storm was likely, the power block would be shut down. Important to note here is that EcoElectrica would be the last plant to come offline in the event of a weather emergency and the first to start up afterward—because of its operational flexibility.

EcoElectrica is certified as an OHSAS 18001 organization. Background: OHSAS is the acronym for Occupational Health and Safety Management Systems. The standard was developed by the British Standards Institute and first published in 1999. Certification speaks to an organization's commitment to meeting health and safety guidelines both now and in the future, thereby creating a safer working environment for employees and contractors.

Although this is not an ISO standard, per se, it is an internationally accepted method for assessing and auditing occupational health and safety management systems. OHSAS 18001 is maintained by the International Standards Organization, however, and it lines up synergistically with ISO 9001 and ISO 14001. Recall that EcoElectrica is certified to the ISO 14001 environmental management process, which is similar in structure to OHSAS 18001.

GM Reyes next reviewed for the editors what he calls EcoElectrica's critical safety elements—a hierarchy of steps reflecting the intent of OHSAS 18001 to ensure the safest plant possible:

- Process design is the first step. It builds safety into the facility by designing and constructing systems and equipment to the world's most rigorous standards. For the LNG terminal the list of standards includes NFPA 59A and 75, 49CFR192 and 193, and ASME B31.8, among many others.
- Process control. The DCS, Scada, standalone PLCs, etc, are arranged and programmed to protect against operation in unsafe regimes.
- Operator intervention complements control-system response when alarms warn of process upsets. Personnel are trained and drilled continuously on operating procedures to maintain their competency and certifications.
- Safety instrumented systems—such as leak and fire detection systems, ignition control, etc—are designed to shut down equipment/systems when unsafe conditions are detected.
- Active protection during incidents—such as that afforded by pressure-relief valves, fire protection/suppression systems, etc—prevents an unsafe condition from getting worse and contributes to elimination of the hazard.
- Passive protection is provided by features designed into the plant and its equipment—such as the double containment for the LNG tank, impoundment areas, vapor fence (Fig 39), etc.
- If all else fails, the emergency response plan is implemented. This may include participation by local first responders, evacuation of personnel in possible danger, etc.

The safety culture nurtured at EcoElectrica underlies the plant's many achievements, including these:

- Annual inspections from FERC and the US Coast Guard consistently without material findings or recommendations.
- Security requirements of federal agencies consistently exceeded on audits.
- No safety incidents reported during more than 165 LNG tanker deliveries since plant startup.
- Evaluations by insurers since 2008 have improved to a "better than a standard facility." Evidence: In 2012, the plant's annual premium was reduced by $1 million. Note that EcoElectrica is not benchmarked against other combined cycles, but rather against petrochemical facilities, which are evaluated to a higher standard.

Training. Health and safety are incorporated into all training modules. Much of this instruction is required by regulatory agencies and part of the plant's compliance program managed by Martinez and Cruz. GPiLearn's online modules are the foundation of the plant's training activities. Employee progress in this activity is monitored by HR Manager Rivera.

Reyes said that a big advantage of GPiLearn is that lessons can be done at home, or on-shift during slack periods. This means the plant can reduce classroom time to a minimum and save on the overtime pay associated with live instruction. Additionally, employees get more time to spend with their families, improving the quality of life. EcoElectrica is working with GP Strategies to develop new training modules and to translate some into Spanish.

Martinez schedules practical training sessions after employees complete their GPiLearn program. Some of these sessions are conducted annually, some on a biannual or triennial basis:

- LNG terminal.
- Security.
- DOT-regulated pipeline.
- Fire brigade.

- Water treatment (boiler chemicals).
- IT procedures.
- Confined-space entry.
- Title V.
- Spill prevention, control, and countermeasures.
- Emergency response.
- Commercial ethics (including sexual harassment).
- CPR.
- Fire extinguishing.
- Hazardous waste operations and emergency response.

Contractor safety. No plant's health and safety program is complete without contractor participation. It is very difficult to bring disparate contractors and other outside organizations up to speed on plant practices in the limited time available for indoctrination and training. Martinez addresses this issue in two ways: An H&S prequalification process to eliminate risky prospective contractors before purchase orders are cut, and reliance on the vigilance of plant personnel to identify risky work practices onsite.

The contractor questionnaire is designed to assess a given company's safety rules, training, history of accidents, etc. It also requires detail on the type of work the contractor will be doing, the type of equipment and hazardous gases and liquids required, the safety risks involved, and how they will be addressed. Contractors with 25 or more employees onsite must have a dedicated safety person at the plant at all times the company's crew is working.

Next step in Martinez's risk mitigation process is the thorough inspection of all equipment, tools, containers, etc, before it can come into the plant. Examples: Slings without valid certification, containers of "mysterious" liquids, etc, are not allowed and must be removed. Once inside, safety training is conducted and all work is coordinated through the plant employee assigned to monitor the contractor's activities. Work permits are submitted through the iMaint system by the EcoElectrica employee, not the contractor.

Finally, a cornerstone of the plant's safety program is its Fresh Eyes initiative. All employees are responsible for reporting safety violations and poor work practices by both plant and contractor personnel—this to correct deficiencies and prevent injuries. It is not punitive. Daily safety meetings include discussion and remediation of all incidents.

Using this integrated process of contractor prequalification, inspection, training, and monitoring of activity, Martinez could not recall ever having to ask a contractor to leave the site. **CCJ**

Cybersecurity: Compliance is not protection

Jason Makansi, Pearl Street Inc

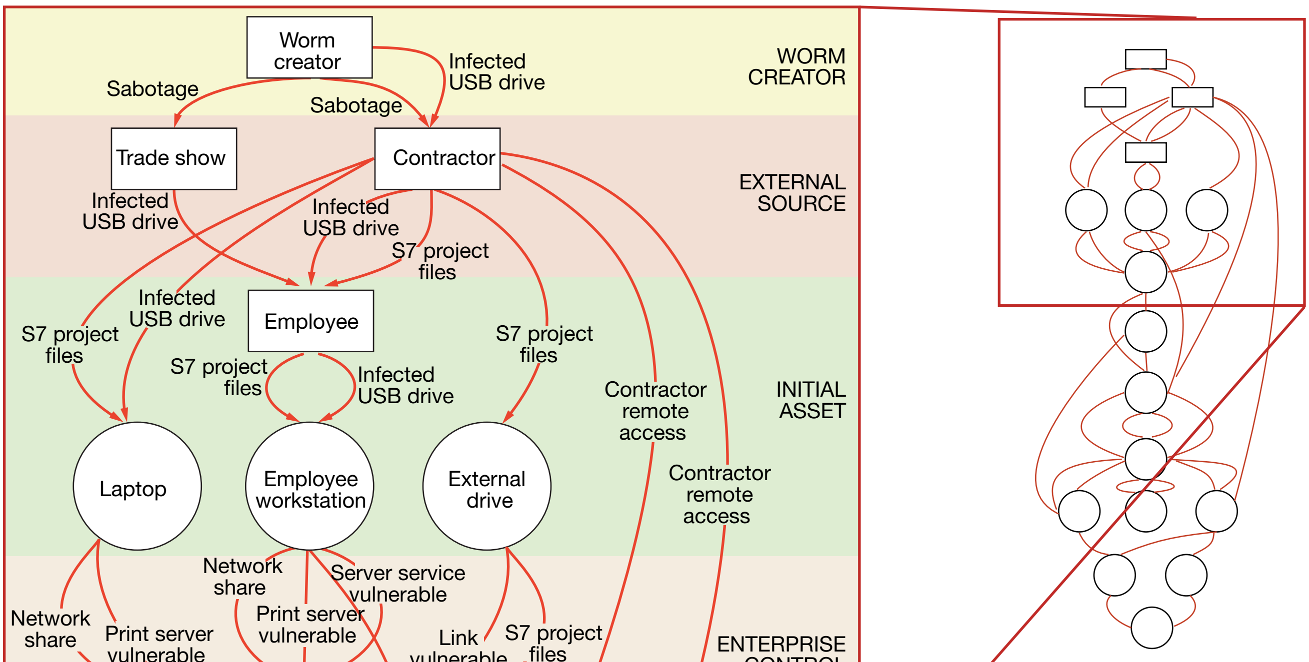
Last August, 30,000 disc drives, representing 75% of the workstations of the petrochemical giant, Saudi Aramco, were hacked with a malicious virus called *Shamoon*. An image of a burning American flag replaced critical data on these machines. In the fall, according to a Dept of Homeland Security (DHS) report, control systems at two power stations were infected by malware delivered through USB drives. One of the plants was down for three weeks before it could restart.

Far more innocuously, while visiting a major utility not long ago, I gave my host a memory stick so he could copy some photos for me. Later, I caught myself: Aren't we all supposed to be more careful? The last time I let a colleague insert a memory stick into my office PC USB port, my operating system froze up. Neither of these involved a powerplant control console, but still.

The now infamous Stuxnet worm infected critical energy facilities by way of a USB port (Fig 1). Attend a cybersecurity conference or pour through the presentations and you might start fortifying your backyard bomb shelter. Here's a good example: "13 Ways Through a Firewall," by Andrew Ginter, director of industrial security, Waterfall Security Solutions Ltd, presented at the DHS Industrial Control System Joint Working Group Conference last fall. Or this one, presented at the same conference: "Certificate Authorities and Public Keys: How They Work and 10+ Ways to Hack Them," by Monta Elkins, security architect, FoxGuard Solutions®.

What's the real threat?

Despite these incidences and scares, combined-cycle managers and staff could, perhaps, be forgiven if the cybersecurity threat is not their foremost thought. After all, it appears that many combined cycles may not have to comply with NERC Critical Infrastructure Protection Standards (CIPS).



1. The Stuxnet worm was initiated by an infected USB drive and ultimately found its way to process control components

Table 1: Selected differences between IT and industrial control systems

Attribute	IT	ICS
Confidentiality (privacy)	High	Low
Message integrity	Low to medium	Very high
Availability	Medium	Very high
Authentication	Medium to high	High
Lifetime, years	3 – 5	10 – 25
Cyber logging and forensics	Available	SIEM* only at the IP layer
Operating systems	COTS	COTS at HMI, RTOS** at field devices
Patching	Standard and expeditious	Non-standard and possibly a long time

*Security Incident and Event Manager **Real-Time Operating System

The latest revision of CIP-002-4 states that plants under 1500 MW may be exempt (although there are other criteria that could ensnare your facility, so don't get smug). And even if you do fall under the standard, there are ways to change that. For example, replacing routable protocols for communication to and from your facility with serial protocols may take your plant off the "endangering the grid" list.

Regardless, you need to stay tuned to NERC's latest requirements, because the criteria for determining which plants are "critical assets" are hotly contested.

The cybersecurity envelope is expanding to include control-system and communications reliability issues, which are not the same as threats from the "bad people." Consider this definition, discussed though certainly not unanimously agreed upon, at the ICS Cybersecurity Conference 2012, held in Norfolk, Va, last October: "Electronic communications that impair machine operation."

It becomes difficult to treat cybersecurity as something special if it morphs to include everything that might go wrong at a power station. After all, reliability is, arguably, jobs one, two, and three at every plant. In many ways, cybersecurity is simply a subset of reliability. Let's face it, the plants that suffered significant downtime between restarts because of a *non-cybersecurity* issue didn't make the news.

Then there are the mountains of paperwork and documentation, and the different standards and guidelines emanating from multiple sources, including: DHS, National Institute of Standards Technology (NIST), NERC, FERC, EPRI, ISA, International Electro-technical Commission (IEC), DOE, and, for a nuclear plant, NRC. Even Congress almost got into the act, which tried, but failed, to pass the Cybersecurity Act of 2012.

According to cyber and control-system experts, none of these standards includes metrics to which you might design your cybersecurity solutions, or aim your strategy. When there is no definition of "secure," all you can do is say, impractically, "more is better." Finally, isn't it the vendor's problem after all? People who run combined cycles typically are not computer programmers.

On the other hand, the cybersecurity threat can be seen as an opportunity to view your facility in a different way. If there was ever a reason to manage the cyber-, or digital, assets of your plant differently from the physical assets, surely cybersecurity is it.

In other work, I have referred to this distinction as the brains and the brawn. Your steam turbine/generator is brawn. Your DCS, your data historian, are brain. With either, if something disrupts your ability to generate the requisite megawatts when called upon, your ability to make money, then whatever the cause, you don't want it to happen again.

It might also be useful to understand what, exactly, is driving cybersecurity and, in particular, the expansion of its definition. One of these drivers is regionalization of our electricity infrastructure. ISOs and RTOs are regional grid and market authorities. In many ways, they function as regional utilities focused on transmission, although two of them, Cal ISO and New York ISO, are bounded by the state, and a third, ERCOT, serves most of Texas.

Since there are no regional governments, the federal government—especially since 9/11, the devastating Northeast blackout of 2003, and subsequent catastrophic outages caused by Mother Nature or human nature—has carved itself a big role in safeguarding the nation's electricity system. NERC is often called FERC's "cop on the beat" when it comes to cybersecurity and reliability.

Finally, cybersecurity is one huge unintended consequence of the drive to make control and information systems more open and less proprietary; use commercial off-the-shelf (COTS) components; break down the information silos and islands of communication; streamline control and automation, diagnostics and monitoring, enterprise information management, and wired and wireless communications; and reduce costs.

Fortunately, the cybersecurity threat can be contained by following these eight basic rules of engagement:

1. Compliance is not protection. Compliance involves policies, procedures, documentation, incident reporting, fines, and enforcement. Your corporate guys may have dotted all the eyes and crossed all the tees on the paperwork, and ticked off all the boxes, but that doesn't mean the operation of your plant is free from threats. However, it appears that the next version of NERC CIPS, Version 5, expected to be approved by FERC this spring, will focus more on security than compliance. Compliance with NERC CIPS V.5 is scheduled for July 2015.

2. IT isn't the same as OT. Most of the cybersecurity analyses and solutions have come from the information technology (IT) side of the house, say powerplant cyber experts, but these vendors are not necessarily the best equipped to handle the potential threats to the operational technology (OT), or industrial control systems (ICS), in the plant. Common distinctions, offered by well-known cybersecurity expert Joe Weiss, Applied Control Solutions Inc, and brains behind the ICS Conference mentioned earlier, are shown in Table 1.

However, it is also important to acknowledge the commercial rivalry between the suppliers of OT systems to the plant, and the suppliers of IT systems that connect the plant to the owner/operator enterprise. The latter includes the ISO/RTO or dispatch center, vendor service and support organizations, environmental compliance monitors, and others, in what has come to be known as the *meta-organization*.

3. Guard the perimeter. The physical boundary of the "brawn" is easy to discern. The electronic or digital perimeter is not. With wireless communications, personal digital assistants (PDA), cell phones, and communication networks everywhere, the perimeter is boundless. There may be a fence around the substation, but the remote terminal unit (RTU) serving it likely is a critical entry point for a cyber-attack. Given that the substation is the link between your facility and the grid, it should be a high priority for your cybersecurity strategy.

4. Air gaps lead back to the dark ages. Many cyber experts advocate for more "air gaps," or electronic/digital disconnects. While theoretically, this can improve security by minimizing digital entry points, air gaps also sacrifice the interconnections which make digital systems so efficient in transmitting and propagating information to devices and workers.

One DHS report notes that the average energy management, SCADA, or plant control system has close to a

Table 2: Top 10 most critical DCS vulnerabilities*

Vulnerability	Impact
Unpatched published vulnerabilities	Most likely access vector
Web HMI vulnerabilities	Supervisory control access
Use of vulnerable remote display protocols	Supervisory control access
Improper access control (authorization)	Access to DCS functionality
Improper authentication	Access to DCS applications
Buffer overflows in DCS services	DCS host access
DCS data and command message manipulation and injection	Supervisory control access
SQL injection	Data historian access
Use of standard IT protocols with clear-text authentication	DCS credentials gathering
Unprotected transport of DCS application credentials	DCS credentials gathering

*Based on possible consequences, impact, ability to detect, attacker awareness, frequency of attack, remediation cost, prevalence
Source: "Vulnerability Analysis of Energy Delivery Control Systems," Idaho National Laboratory, September 2011

dozen connections to outside networks. And that doesn't include the networks used by each authorized worker who could access the system at one point or another.

Another problem with air gaps is that workers will defeat them by carrying data across the gap with portable storage media. Some experts suggest alternatives that, while complex, offer life- cycle flexibility and a true solution rather than incremental fixes, patches, and relentless password and validation checks (see sidebar).

5. Get beyond the HMI (human machine interface). Chances are, the cybersecurity threats you aren't thinking about are lurking in the programmable logic controllers (PLCs), RTUs, and I/O terminals in the plant. Every computer chip or card receiving or transmitting electronic/digital signals to another device is a potential point of malicious or accidental entry. Also, employees and their PDAs and cellphones, sardonically referred to as "bring your own device" (BYOD) by cyber-experts, have to be considered points of entry. Employee PDAs should be secured, or separated from critical networks.

6. Think about the entire supply chain. Unfortunately, every line of computer code is an opportunity for malicious entry into the system, say cyber-experts. Consider the supply chain for your digital system—where the hardware components are sourced, where the programmers reside, who puts the system together, who services the system, and so on.

Cyber specialists note that while vendors on the IT and OT sides are designing and offering solutions, system integrators are the missing link. Just like an EPC contract with warranties creates one entity responsible for seeing that the plant design meets performance criteria, it may be inevitable that one entity becomes responsible for the cyber health of your digital assets.

7. Think about critical assets, even outside of NERC CIPS. When conducting a reliability-centered maintenance (RCM) program, you (1) identify those components that can really cause trouble, (2) pay close attention to them, and (3) allot them a greater part of the maintenance budget. The same

Infrastructure	Ports, servers, patches, applications, events, and other stuff (OS, etc)
+	
DCS/PLC hardware	Application, operator, and engineering work stations, plus I/O cards/FBMs and controllers
+	
Manual data entry	Plant criticality, black start, must run, megawatts, routable protocol, modem connection, cyber critical asset, reference ID, ESP segment ID, external accessibility ID, PSP boundary ID, appropriate use banner
+	
People	Users, access, passwords, training, etc
+	
Discovery	Approved devices, unapproved devices
=	
Inventory	The sum of the parts is one inventory item

2. Proper inventory of your cyber assets and devices is one of the pillars of a protection program

should be true for cybersecurity. One caution: Don't blindly accept vendor designs that mix safety logic and control-system logic—they may save money but are by no means a cybersecurity best practice.

8. Inventory your cyber assets. In addition to guarding the digital perimeter, creating a thorough inventory of your cyber assets, and organizing them, is a pillar of a cybersecurity management program.

Embedded digital devices

It's critical to place what you hear and read about cybersecurity into context. For example, at the ICS Conference referred to above, experts noted (1) PLCs are especially easy to overwhelm because the code is relatively simple, and (2) system integrators are the missing link when it comes to designing and offering solutions.

One expert specifically mentioned that Rockwell Automation's PLCs are priority targets for hackers. On the one hand, this makes sense because PLCs are COTS components specifically designed for ease of programming by end users and integrators. In addition, Rockwell is recognized as a PLC supplier that relies on its extensive and capable network of integrators.

Part of the context also is that PLC-based automation systems are now competing with distributed control system (DCS) architectures for core plant functions. Traditionally, powerplants have used a DCS for the core process, the gas and steam turbine/generators, and HRSGs—and PLCs for auxiliary sub-systems like water treatment. Today, gas-turbine and combined-cycle systems are relying more and more on PLC-based automation.

Thus, some cybersecurity issues may be at least partly derived from commercial rivalries among PLC and DCS suppliers (although the distinction between the two has blurred) and among OT system suppliers and IT system suppliers.

Inventory

It's one thing to create an inventory of cyber assets around critical infrastructure. It's another to keep it up-to-date. Maintaining the accuracy and currency of any database is difficult. For digital automation systems, it all comes under the rubric of change or configuration management.

PAS Inc, Houston, which has built cybersecurity compliance solutions for a large owner/operator with multiple assets across a broad region, suggests the following categories for building a complete inventory: Infrastructure, DCS/PLC hardware, manual data entry, people, and discovery (Fig 2). Each of these categories, in turn, possesses certain attributes that can affect the health of the cyber asset, and therefore the ability of the component, as part of a critical asset, to function properly. It may

Consider 'virtual isolation' for plant security

In a relatively new concept, Lee McMullen, cybersecurity specialist at Hurst Technologies Corp, Angleton, Tex, suggests employing a virtual-machines architecture to manage cybersecurity without sacrificing the productivity gains inherent with information sharing through the meta-organization from an integrated digital automation system. Think of a virtual machine as a software program emulating a physical computer that runs on the host computer. Depending on the power of the host computer, it can run multiple virtual machines.

The virtual isolation concept uses a host computer configured with a minimum of two virtual machines. The first virtual machine is outside the plant system connection and communicates with the corporate or other non-process networks. The second virtual machine, on the inside, connects to the process systems. The host computer manages and monitors both virtual machines and acts as a data and communication isolator.

On the inside, the virtual machine receives data from the legacy systems and transports data through the host to the outside virtual machine. To enhance security, the host computer monitors all transactions and maintains an *auditable transaction log*. Data requests and limited control commands from the outside virtual machine are submitted to the host computer where they are verified for security authorization and screened for malicious content then passed to the inside virtual machine.

To maximize flexibility and further enhance security, each virtual machine and the host computer's operating systems utilize separate, dedicated disk drives and network cards within the host computer. The custom hardenings of each virtual machine, claims McMullen, allows the most efficient and secure configuration method possible for connecting multiple networks using a single physical machine.

Standard hardening methods include network isolation, port control, and various secure communication schemes. These methods should be applied to each virtual machine as required by their connected networks. One option that is unique to the virtual machines is the capability to run different operating systems within the virtual isolator to maximize security.

The virtual machines and their isolated network connections support custom applications that provide a method of passing data from the legacy process system communication network to the corporate network, as well as passing commands and data requests to the process network.

There are three levels of security in this configuration:

- Network connectivity on the corporate side is limited to only the specific ports necessary for passing information requests to and from the outside virtual machine.
- The receiving application only accepts information request messages previously identified in a control database on the host computer. This host database is not accessible to either the enterprise or the process networks, only working within the host computer.
- Communication and security configurations are unique to each virtual machine and the host computer. This ability to tailor the configuration for each application and legacy system allows the greatest possible level of integration and security while reducing overall complexity and cost.

A user outside the plant system submits a request for information to the enterprise virtual machine either through a web interface or through a dedicated client. The user request is logged to the enterprise virtual machine's database where it is parsed to determine if it is a valid request. The validity of the request is verified using standard, current security processes. Once validated, the host computer extracts the desired information from the process database and returns the data to the enterprise virtual machine in a temporary file.

Control function requests are passed in the same manner. The desired function is received by the enterprise virtual machine and then is evaluated by the host computer. If the requested function is valid and the security of the requestor properly verified, the host will pass the instruction on to the process virtual machine for execution. The process virtual machine will receive the control instruction then evaluate the instruction against the current state of the process system.

If the instruction passes all these checks, the process system executes the command. If it fails, the control instruction is rejected and the requestor notified. This introduces a delay for control but provides a secure method for passing a control command from outside of the process network.

look straightforward on paper, but now think about every component in your plant that can be considered a digital "point of entry."

Guard the perimeter

Cybersecurity experts and government officials insist that bad guys are continually poking digitally at the perimeter seeking malicious entry (Table 2). Sometimes they get in. But after a review of the public information on powerplant cybersecurity, it appears that avoidable losses boil down to rather mundane, common-sense strategies. For example, preventing an authorized person from inserting an infected memory stick into the wrong port would have prevented the cyber-incident referenced at the beginning of this article.

So, there needs to be a way of verifying that any portable storage device is safe before it is inserted into a USB port or a disc drive. Such devices can be scrubbed before insertion or so-called media designed for a single use can be more widely deployed. As in the RCM analogy, obviously it is more critical to ensure this for a plant operator's control console, or a PLC or I/O port at the gas turbine, than it is for a plant engineer working remotely through a PC with off-line data.

Passwords are a similar issue. Experts suggest replacing role-based passwords (example: plant engineer) with personal passwords for each potential user. It may be a nuisance to constantly change passwords, or make them longer, more complicated, and more defensible. But it is also a nuisance to pass through a security machine whenever you board a plane, visit a government office facility, or even have a meeting at a major New York bank headquarters. But we've learned to live with it.

Patch management is a third element of guarding the perimeter. As everyone knows from their PC experience, software suppliers regularly deliver patches and anti-virus protections as they are developed to counter known threats. OT software vendors now do the same thing. However, this can be dicey because vendor security solutions often incur safety impacts—especially if legacy software is still being used in other parts of the system.

You may have a great HMI screen but the controllers underneath may still be running Windows 98.

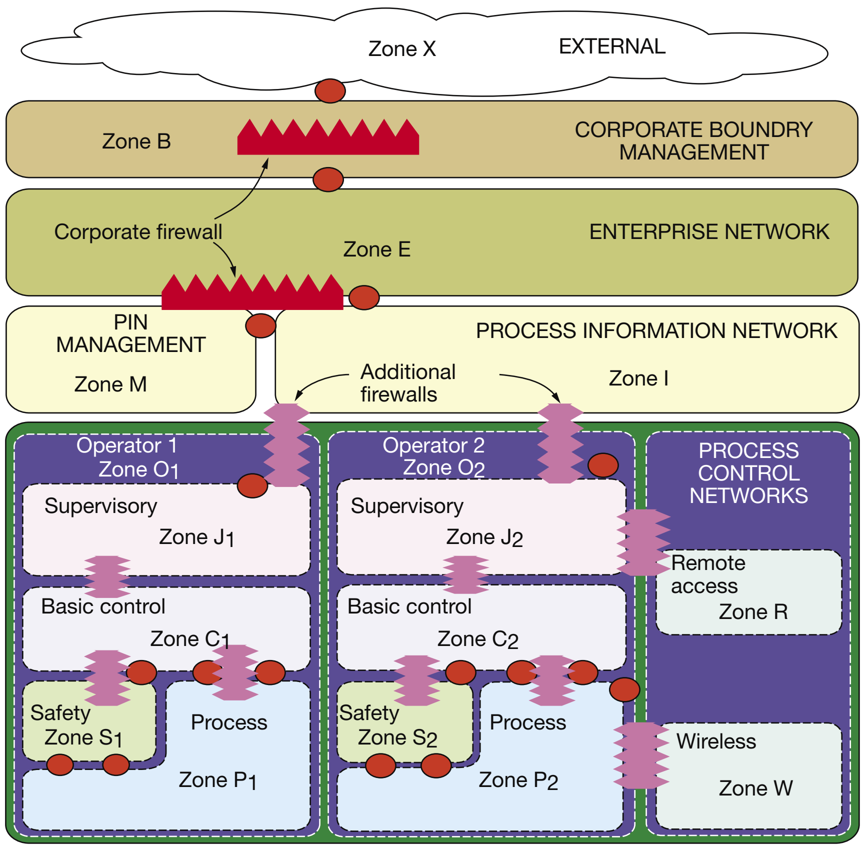
The other major problem with patch management, according to ISA standard TR-62443-2-3, "Security for Industrial Automation and Control Systems: Patch Management in the IACS Environment" (formerly ISA 99) is that patches typically are rolled out during scheduled maintenance outages.

The timeline for outages isn't the same as the criminal's timeline for injecting malware or the urgency to address software bugs. Some digital systems used at power stations are old and not well supported by vendors. Patches may simply not be a solution in many cases. Finally, patches themselves may be corrupted, or adversely impair the operation of the software it is intended to correct.

Robust, more permanent

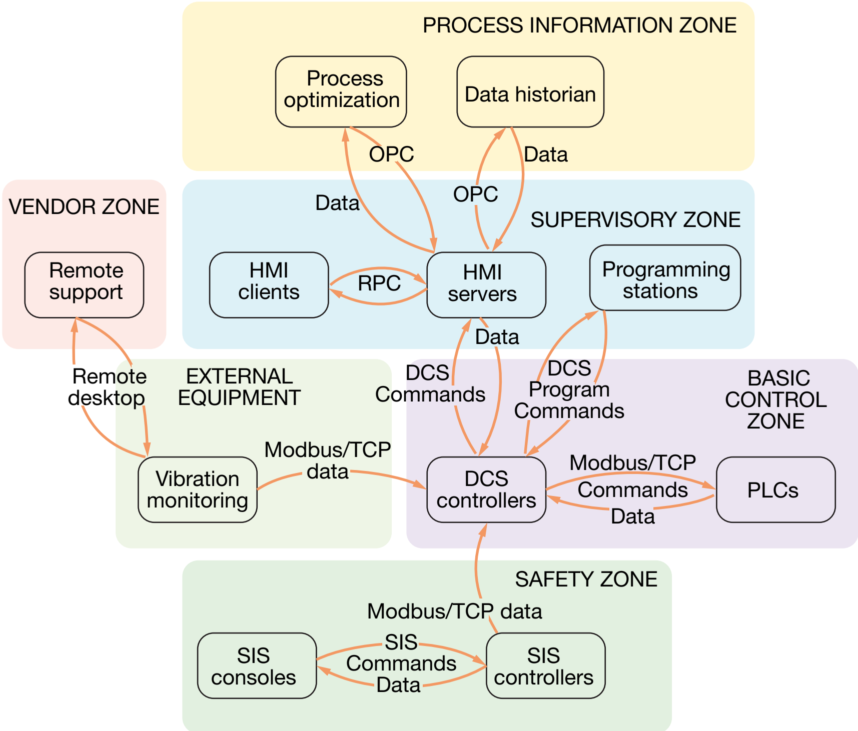
A permanent solution to cybersecurity is probably a pipe dream. No one has figured out how to stop crime. But it does seem clear that the cyber community is moving towards solutions that are more robust, more permanent, and less dependent on patches, digital pat downs, and passwords.

For example, Torfino Security Inc suggests dividing up the digital system

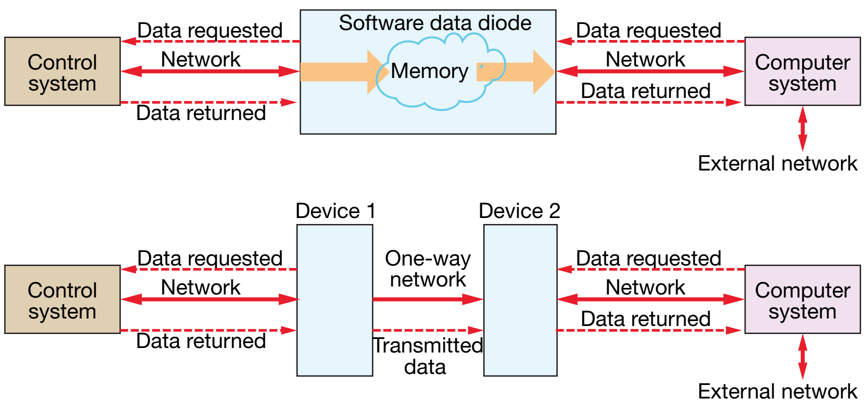


Source: Torfino Security Inc

3. Multiple firewalls below the corporate/enterprise level is recommended by some cybersecurity experts



4. Once the digital system zones and conduits are identified, the next task is to define all the data flows among those zones and devices



5. Software (above) or hardware data diodes allow data and information to flow in only one direction, from the powerplant out to external systems and networks

into zones, identifying all conduits between and among zones, and then defining the data and information flow through those conduits. Additional firewalls can be established below the enterprise and corporate firewall levels (Figs 3, 4).

Another appliance is called a universal threat manager. At least one powerplant cyber expert at the ICS Conference stated that he was a "big fan" of UTM. It is described as a special type of firewall combining packet inspection, network anti-virus protection, in-line network intrusion detection sensor, intrusion prevention system, and built-in authentication mechanisms. An example location would be the conduit between the plant's data historian and the corporate or enterprise information network.

A third device for protecting the perimeter is called the data diode (Fig 5). As the name implies, the data diode allows data to be transferred in only one direction, or uni-directionally. It is inserted between a source of data at the plant control system and the computer system or network, and can be hardware- or software based. The hardware diode may be the more secure approach because a software diode can be accessed from the computer, or remotely, and "converted" into a bi-directional pathway.

According to Barry Hargis, Engineered Solutions Inc, in a presentation at the 55th ISA Power Industry Symposium, a hardware data diode completely protects the powerplant control system from a cyber-attack while still allowing data to flow out of the system. However, diodes involve additional costs, they create latency (delays), in data transmission between the control level and the computer system, and they may not be appropriate for all data sources—such as for protective signals, controller-to-controller signals, etc.

Post-mortem incident analysis

A visceral presentation given by a powerplant engineer at the ICS Conference illustrates many of the conflicting issues in cybersecurity.

A 1980s-vintage coal-fired plant with 400-MW units had to replace its legacy control system. The system in place now includes 4500 I/O points, Ethernet communications, boiler and turbine control, burner management system (BMS), data acquisition system, data historian, OPC (Object Linking and Embedding for Process Control), relay logic systems (PLCs), sequence-of-events (SOE) recorder, annunciator with pan alarm windows, and other pieces and parts. This information now comes through one HMI. The data historian (third party) has a hard connection into the DCS.

In the meantime, the OPC vendor had to supply a patch for the FTP (file transfer protocol) server associated with the data historian. Here, Microsoft middleware is used for machine-to-machine communication. To insert the patch, the plant had to be "shut down and cold," according to the presenter.

After final tuning of the new DCS, the plant was ready to start up. Operators fired up the boiler. Not long after, trending of the I/O points slowed down, then, much to everyone's consternation, stopped working. The application processor was no longer updating the HMI. All-important trends in the BMS were not visible. Operators had to trip the unit.

Unfortunately, the startup sequence continued in cruise control but operators had no control capability and no view into the vendor's "fault tolerant" computers. No alarms came on at the HMI (although alarm signals were apparently available at the processor level), because the alarm management system was embedded in the HMI.

The problem of controllers talking to each other with no operator visibility was not experienced during factory acceptance testing of the DCS. The plant waited an hour for the vendor to respond and reset the process. In the meantime, the plant had achieved 60% MCR.

Fortunately, control was restored before a catastrophic event occurred.

The root cause proved to be redundant OPC servers corrupting the data from the DCS because they could not correctly handle time-series data and were losing the SOE recorder data.

Here are some of the takeaways offered by the presenter. While this was not a "bad guy" cyber-incident, it met the broader definition of an "electronic communication between systems affecting confidentiality, availability, reliability, or other performance attributes."

- OPC is "black box" software code and you need to understand the "guts of it,"—the original platform it was built on.
- Vendors consider their software code proprietary and resist the notion that customers must see it. In fact, customers are specifically prevented from this knowledge when they sign a software user agreement.
- Vendors must provide root-cause analysis that is acceptable to the customer.
- Field IT has to be designed to a different standard than corporate IT. In this case, a simple network upset had vast potential consequences.
- Remote vendor log-in is a potential portal for cyber-threats—the plant doesn't necessarily know the vendor's people at the remote help site.
- You cannot divorce change or configuration management processes from cybersecurity processes and procedures.
- Automation systems do not "plug and play" the way you might think.
- Digital systems may have become so complex, no one person can know how they work or which vendor is responsible. CCJ

Gas-fired facility reflects TVA's transition to the new era

1. TVA's John Sevier plant, once a workhorse, 1950s-vintage coal plant, entered a new era with the addition of an 870-MW gas-fired combined cycle

If you were searching for a powerplant where the industry issues you keep reading about have converged, you probably couldn't do better than Tennessee Valley Authority's (TVA) John Sevier Combined Cycle Plant. On a site where four 1950s-vintage unscrubbed coal-fired units no longer run, a state-of-the-art 3 x 1 natural-gas-fired combined cycle (Sidebar) now operates at high capacity factor because of the favorable price of fuel (Fig 1).

The rail delivery line that you parallel on the long drive into the reservation is idle. The dust and grit of coal handling and preparation have settled. The tall coal plant stacks, built in the days of "the solution to pollution is dilution," are stone cold, replaced by the short squat stacks typical of a gas plant.

As a TVA employee (of short duration) several decades ago, the writer worked on emissions testing and control projects at seven of the utility's coal-fired plants. Although skeptical of the latest rhetoric around the shale-gas revolution over the long-term, he sensed while driving slowly under the canopy of trees lining the drive to the plant from the road, that he was being deposited into a different era. Time will tell whether the big switch from coal to gas becomes reality nationwide. But the stirrings of the new era whispered through the trees.

Critical as ever

One thing that hasn't changed is how critical the site is to the TVA system and this substantially dictated the design and the first months of operation. Limited transmission exists in the northeastern part of the TVA system and much electricity is wheeled in from long distances—including power from wind turbines in the Midwest and from fossil-fuel-fired merchant plants in Mississippi.

Lots of VArs have to be injected in this location. The new Sevier plant essentially is used to regulate the eastern portion of the system. The plant is almost always operating, but its output is always swinging too.

"We will ramp from 480 to 760 MW often twice a day, sometimes twice even within a couple of hours," noted Terrell Slider, plant manager. "Our capacity factor has been around 80%, but our online time has been more like the mid-90s." Other combined cycles in the TVA system are in daily start/stop mode, but Sevier regulates the system at night. "We're dispatched such that we've hardly had time to focus on heat rate," Slider added.

In fact, flexibility and reliability are the hallmarks of the plant's design objectives. With a 96.5% availability and a 1.6% equivalent forced outage rate (EFOR) reported for fiscal 2012 (May through September), it appears those objectives will be achieved. To put that in perspective, the plant just completed construction in April 2012, one month ahead of schedule and under budget.

"Must run" at this site means that two 2-million-gal tanks loaded with back-up fuel oil are included along with a continuously operating fuel-oil recirculation system, allowing fuel for the gas turbines to be switched "on the fly" if and when necessary. The plant can run for 100 hours flat out on its back up fuel (without duct burners, which are only gas-fired).

Because Sevier must meet a 42-ppm NO_x limit on fuel oil, demineralized water storage is also provided for water injection into the gas-turbine combustors. The fuel-oil back-up systems have been tested for all three GE 7FAs. Back-up fuel capability added 10% to the plant's capital cost.

Other design characteristics for reliability are more familiar to the combined-cycle community. Each gas-turbine train has a bypass stack, for seamless and immediate conversion to simple-cycle operation, and duct burners in the heat-recovery steam generator (HRSG) boost output from the steam bottoming cycle when necessary.

The plant can run with any combination of gas turbine/generators (GT/G) and the steam turbine/generator (ST/G) running; however it

Key facts about Sevier

The John Sevier Combined Cycle Plant was built in 24 months, one month ahead of schedule, coming in under the $820-million budgeted and with zero lost-time injuries. Twenty-six of the 31 plant staff were transitioned from the adjacent idled coal plant. A few additional personnel are on staff for upkeep/layup tasks associated with the coal units.

Plant major components include the following:

- Three GE 7FA.04 dual-fuel gas turbines equipped with evaporative coolers are each rated 176 MW on natural gas and 185 MW on distillate oil.
- Three triple-pressure HRSGs with duct firing are equipped with catalyst modules for NO_x and CO reduction (Fig A). An aqueous ammonia (19.5%) storage and feed system serves the SCR system.
- A gray-market 400-MW (with full duct firing in operation, 280 MW without) tandem- compound, double-flow, reheat condensing steam turbine/generator manufactured by Toshiba Corp. The steamer is installed outdoors, perhaps uncharacteristic for a plant at this location (Figs B, C).
- A 12-cell mechanical-draft cooling tower.
- Main pumps: Two 100% boiler feedwater pumps for each HRSG, two 50% circulating-water pumps, and three 50% condensate pumps.
- Water for plant operations (service water, demineralized water, and cooling-tower makeup) is pumped from the river in two existing bays at the coal plant to the make-up water pretreatment system. Product is stored in two 500,000-gal service water tanks.

Although combined-cycle performance is not under warranty, performance of the GT/Gs in simple-cycle service is guaranteed by GE. Engine NO_x emissions when firing natural gas is warranted at 9 ppm or below, 42 ppm or below for distillate fuel oil. Catalyst modules in the HRSGs further reduce emissions to a guaranteed 2.5 ppm NO_x and 3.5 ppm CO. The boilers are designed for mostly natural-gas firing, with 200 operating hours per year on fuel oil.

A diverter damper cuts off GT exhaust flow to the HRSG when the plant operates simple-cycle. An additional guillotine damper assures safe working conditions downstream to permit work in the HRSG and beyond with the GT/Gs in operation.

A. The triple-pressure HRSGs employ supplementary duct firing and include catalyst modules for NO_x and CO reduction

B, C. Sevier features outdoor construction for the steam turbine. Companion photo at right shows installation of the LP rotor

cannot go from straight simple cycle to combined cycle. To meet NFPA (National Fire Protection Association) code requirements, the HRSGs must be purged with large volumes of air prior to flowing hot exhaust gas through them. Typically, the three gas turbines stay online and are backed down in load (in combined-cycle mode) overnight.

To illustrate the impact of fuel prices, the original design called for an expected 40% capacity factor (CF). After the plant went into service, dispatch was asking if 95% CF was achievable. In fact, the benefit of operating the plant at last summer's fuel prices was so great, TVA essentially started the commissioning period before construction was complete to take advantage of the market.

"The bypass dampers were a benefit," said Mike Hoy, senior manager for construction projects, New Unit Services, "we could run the GT/Gs independently while we were still working on the steam system, and also separately test the engines on both fuels and conduct the GT simple-cycle performance tests."

Risks versus rewards

While reliability and availability are critical, TVA undertook some calculated risks to reduce costs. For one, Sevier makes use of about 50% of the design intended for another site—the Gleason project. For another, a gray-market ST/G in storage for 10 years was pressed into service, as well as the HRSGs—already ordered for the earlier project.

Third, unlike most other combined-cycle projects, TVA enlisted EPC firm Kiewit Power, to construct the plant. Another firm, URS Corp, handled engineering and procurement. The consequence: No overall plant performance guarantees. TVA accepts the liability for system performance, which, the construction team stressed, is not standard practice at the agency.

While it was convenient to include the existing ST/G in the design, getting the unit to the site was a different story. For example, the rail envelope for the generator was too large for East Tennessee (mountainous area). It had to be barged from Memphis to Knoxville, then trucked from there, including temporary closures of the busy Interstate 40 (Fig 2). The HRSG components were sized based on the rail envelope for the Gleason project. They also were shipped by rail to Knoxville and trucked from there to the plant.

2. Transport vehicle used to move the steam turbine and other large components to Sevier from Knoxville, where they had been off-loaded from a barge originating in Memphis

The Toshiba Corp steamer was modified based on 10 years of field operating experience. Said Hoy: "The most invasive mod was replacing the single-bolt fan blade on the generator's rotor with a two-bolt design." The original bolts were showing premature fatigue on operating units in the field. Corrosion and missing parts issues also had to be addressed.

Early O&M experience

Getting the plant built under schedule and budget is one thing, but the plant operating staff had to confront some additional challenges. At the top level, the plant has not achieved the expected total output of 870 MW (summer, duct-fired) but, according to Slider, "has demonstrated 834 MW on a winter morning with 22F ambient air." This was without duct firing.

In addition, the maximum expected ramp rate is 45 MW/min for the gas turbines, but until additional HRSG tuning and testing is performed, the plant is only comfortable with the 20-MW/min ramp rate it is now operating under.

Slider stressed that the issues weren't so much ones of deficient plant capability, but that "we had to discover things during commercial operation that normally would have been identified and corrected during commissioning. And the lack of a warranty (other than the GT/G) means we can't hold the designer to its design."

In general, Slider felt that there weren't enough acceptance criteria—especially for the control logic—included in the contract, and the ones that were included could have been better defined. As with other combined cycles, problems with control logic have led to some downtime.

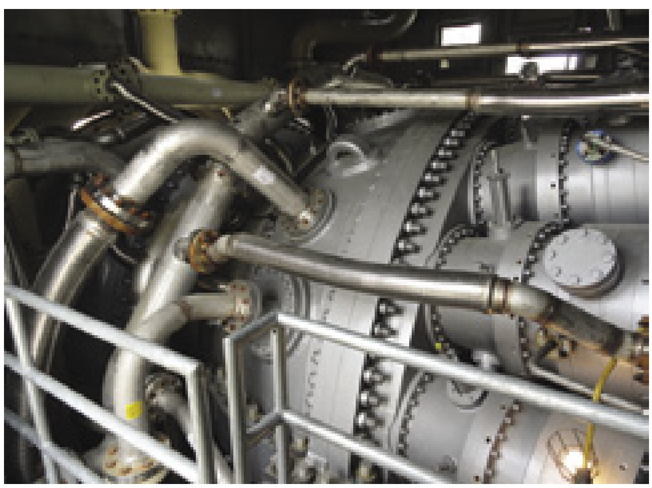
Some specific O&M issues reviewed with the plant staff include those listed below. They provide a valuable checklist for others involved in combined-cycle projects.

Gas turbines. The latest F-class turbines (Figs 3. 4) have exhibited no real issues to date. Compressor rubs have been detected, but no actions have yet been taken.

Valves, actuators, transmitters. There are too many vendors and too many styles: The plant would have benefitted from a greater degree of standardization. Boiler-feed discharge valves were specified incorrectly and valves in the feedwater system bind up.

Guillotine dampers pose recurring problems. The actuators kept wearing out because they were cycling when they weren't supposed to or didn't need to. Noted Slider, "The guillotine dampers were never put through the paces of commissioning."

Bearings failed prematurely



3, 4. One of Sevier's 7FA.04 gas turbines is offloaded at the plant; second photo shows unit during commissioning because of poor greasing practices. Bearings for the cooling-tower fan motors had no grease in them at all.

Fuel-oil check valves. Oil leaking past these valves entered the combustors and altered NO_x readings; however, valve replacement appears to have solved the problem.

GT closed-cooling radiator fan skids. Some issues in the control logic for this subsystem has led to icing on (and bending of) the grill below the cooling fans. The fans run continuously and shouldn't be, according to Slider. A mixture of water (55%) and propylene glycol (45%) serves as the coolant.

Fuel gas heaters. While the plant was designed with redundant 100% dew-point gas heaters, the system has proved inadequate, mostly because of the unexpected critical nature of fuel-gas Wobbe Index/Temperature criteria for GE gas turbines. The single chromatograph also is a liability.

The allowable GT fuel-gas temperature falls in a narrow range. If the gas is too hot, the unit trips. The fix has been to keep one gas heater cool and the other hot with temperature-controlled valves to divert gas between them and maintain the required temperatures. Unfortunately, this eliminates the redundancy designed into the fuel-gas heating system.

Fuel gas supply. Debris entrapment issues resulted because TVA policy did not permit gas blows of the fuel supply lines. The dual-basket gas filters plugged up and a design flaw was uncovered that resulted in the identification of a single-point failure location.

Water treatment system:

- Motors on the clarifier pumps that remove the sludge were incorrectly specified and had to be replaced.
- The routine cleaning basis for the polymer injection valves had to be altered via a corrective maintenance procedure.
- Algae growth/fouling issues in the GT evaporative cooling system arose from poor water quality.

Valves for double block and bleed. A TVA-wide procedure calls for double block and bleed, and some of the extra valves were causing problems, especially in high-temperature/high-pressure situations.

General QA/QC. There have been instances of loose tubing, loose connections, and inadequate heat tracing.

Accessibility. There are areas that cannot be accessed and additional scaffolding, ladders, and platforms will have to be added.

Additionally, the plant is still struggling with some interrelationships among the duct firing, steam attemperator, and water chemistry sub-systems. During initial duct-firing operation, the team uncovered a lack of attemperator capability for HP steam. After attemperator modifications were performed during the fall outage, steam carryover is now in evidence from the HRSG drums.

The plant has had to back off on duct firing because of water-chemistry constraints. Said Slider, "Until we resolve these and other issues, we're not going to be comfortable operating at maximum duct-firing design."

Given the availability and reliability numbers achieved in the first few months of operation, the plant clearly and successfully has managed the usual challenges of early operation. While "startup was essentially by the seat of our pants," Slider said they are pleased with overall plant performance. He further noted that any of the issues not associated with the quick commissioning period could have been avoided by having the operations group involved in establishing acceptance criteria.

The construction team also remarked on some of the issues faced by the plant. "We were the first to receive this latest model gas turbine as a production unit, and we are experiencing some of the teething problems expected with that," said GM Roger Waldrep, New Unit Services, Construction Projects. Many of these are associated with the Mark VIe controls software. "We're all getting educated on how to run the heaters and the sensitivity of GT operation to fuel-gas temperature," he added.

Although there were extensive tests included in the acceptance criteria, one that was not agreed to by the contractor is the full-load steam rejection test. "Unfortunately, we did not have the luxury of time necessary for conducting all of the testing we all would have preferred," said Waldrep. Senior Manager Dan Tibbs added, "The plant is designed to operate at 160 MW minimum load in a one-on-one configuration," meaning it can safely maintain 18% of full load when called upon by dispatch.

Design, construction features

The original impetus for the project was TVA's need to meet its obligations under the Clean Air Act, as well as an order by the US District Court for the Western District of North Carolina to install NO_x and SO_2 emissions controls on the coal units by Jan 1, 2012. Installation of clean-air controls on the coal plant could not be implemented in the original court-mandated time frame. Idling coal units and replacing the capacity with the combined cycle proved to be the best solution.

Adding 870 MW to an existing site naturally poses its own unique benefits and challenges. On the benefits side of the ledger, the combined cycle was able to take advantage of common air and National Pollutant Discharge Elimination System (NPDES) permits with the idled coal units. The plant has to meet annual tonnage caps for CO and NO_x emissions. Also, the combined cycle shares the water intake structure of the old units. Although only four coal units were built at Sevier, the site was originally prepared for six.

In place for repurposing, of course, are the transmission lines to the coal units and a nearby 500-kV substation originally built to serve the Phipps Bend nuclear plant, which was never built, and to interconnect Sevier. One line from Sevier to Phipps Bend was used to tie two of the new GT/Gs into the substation, while a second line was used for the third GT/G and the ST/G.

For its 150-million-decatherms/day gas supply, Sevier maintains a firm contract with one supplier, Spectra Energy (East Tennessee Natural Gas LLC). An 8.5-mile, 24-in.-diam lateral was constructed over rough terrain to the main supply line. Although pipeline pressure is pretty close to what the plant requires, a reducing station resides on the TVA site downstream of the Spectra meter.

Most of the combined-cycle staff just had to change parking lots at the site, but after that, there was some culture shock in going from coal-plant to gas-plant operations. Workers who were once plant operators are now operating technicians and have far more responsibilities under the multitasking regime typical of combined-cycle plant management.

Finally, financing of this facility is also unique for TVA, but may not be for long. The lease-buyback financing strategy employed is being evaluated for upcoming projects, including nuclear. Like the federal government, the agency operates with a debt ceiling. To remain under its $30-billion cap, TVA is making use of lease-purchase agreements with private equity firms.

According to news reports early last year, TVA leases the plant from John Sevier Combined Cycle Generation LLC, a special-purpose entity created with $100-million of equity from members of the financial group (composed of large institutional investors) and $900-million of debt raised by the group through the sale of bonds. Overall, TVA will pay the financing entity $1.3-billion ($300-million in interest) after 30 years, when ownership reverts back to the Agency. "Think of it like a home mortgage," noted Hoy and Waldrep. CCJ

Clashing, controls, refurbishment of hot parts top topics for ageing fleet

Conferences of the 7EA Users Group traditionally begin with a State-of-the-Engine report by Advanced Turbine Support LLC, Gainesville, Fla, the inspection specialists who rely on borescopes and an assortment of nondestructive examination (NDE) tools to check annually the internal condition of more than 1000 gas turbines of all types. ATS is respected industry-wide for sharing its findings to help all users.

At the 2012 meeting of 7EA owner/operators held late last October in Greenville, SC, the Steering Committee's senior member, Pat Myers, plant manager of AEP's Ceredo Generating Station, introduced ATS President Rod Shidler and Service Manager Mike Hoogsteden to deliver their yearly assessment.

As Hoogsteden dug into the details, it became apparent that the number of issues identified each year in the ageing fleet is increasing. It's more important than ever, he said, to perform inspections regularly and properly to prevent "issues" from developing into catastrophic losses. Then Hoogsteden stressed the need for owners' engineers to review promptly documented findings and to develop and implement programs to mitigate identified risks.

Clashing. For many attendees, the highlight of the presentation was ATS's five-step clashing mitigation procedure that Hoogsteden introduced to the group. Recall that clashing—the term used to describe contact between rotating blades and stationary vanes in Frame 7 compressors—has been a hot topic for years at the 7EA meeting.

The service manager said that ATS inspectors have documented clashing damage to the trailing edges of R1 rotor blades (Fig 1) and to the leading edges of S1 stator vane tips (Fig 2) for the last five years. More importantly, accurate measurements of the damage have been taken over the last three years and records maintained for each affected vane using the OEM's stator-vane numbering system. In several cases, data have revealed increases in clashing damage over time.

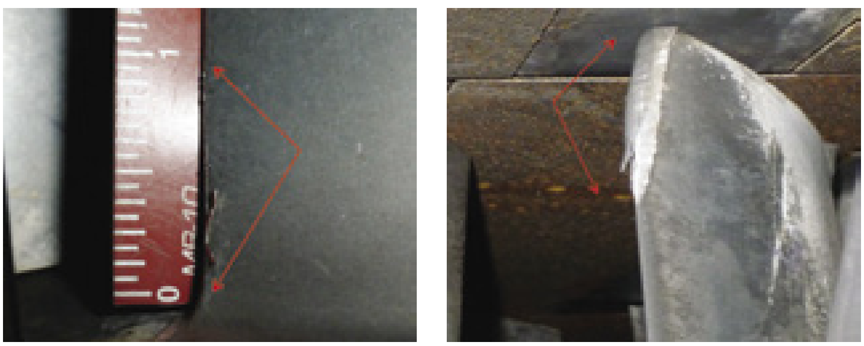
Absent a Technical Information Letter (TIL) on how users should address clashing damage, ATS offered the following procedure:

1. Check for clashing damage during your regular semi-annual or annual borescope inspection.
2. Perform an in-situ red-dye penetrant inspection on the trailing-edge platforms of rotor blades, stator-vane tips, and on the convex side of stator vanes where damage is in evidence.
3. Blend/crop in-situ the affected airfoils. The extent of the repairs is determined by the type of damage identified during the first two steps.
4. Apply in-situ an approved lubricant/rust inhibitor to the platforms of damaged stator vanes. Note that current industry thinking is that vane lock-up attributed to rust and other airborne debris is at least partially responsible for clashing.
5. Monitor/trend results. Appropriate intervals for follow-on inspections would be determined by the extent of the mitigation process implemented.

As to the cause of clashing, several users told the editors they attribute the problem to (1) deflection caused by the inlet being restrained from free movement during thermal expansion and (2) a change in the resonant frequency of the S1 airfoil caused by rust buildup in the lower casing that "locks" vanes in place. This would explain why clashing did not occur initially and may progress in severity as the units age.

TIL review. Hoogsteden spent most of his time at the podium discussing what ATS believes are the OEM's most important TILs regarding the 7EA compressor. Much of this information had been presented previously and discussed in past issues of the CCJ, but more than half of the 120 or so attendees were first-timers and the review was particularly valuable (Sidebar 1). The following is a list of the TILs covered and the issues they addressed, with publication dates in parentheses:

- 1132-2R1, spring and thrust washers for variable inlet guide vanes (Dec 15, 2004).



1, 2. Rotor blade damage from clashing is in evidence on the trailing edge of the R1 airfoil at the left, just above the platform. Tip damage on the leading edge of the S1 stator vane at the right also is attributed to clashing

Know your 7EA turbine

With more than half of the owner/operators participating in the 2012 Conference of the 7EA Users Group first-timers, one had to believe that many of them never saw the rotor out of the casing. Consider what follows an "orientation" program to help you get to more familiar with your 7EA workhorse.

The nominal 85-MW 7EA gas turbine, which first entered service more than 30 years ago, has been used in a wide variety of utility and industrial electric-generation and mechanical-drive applications. As a power producer, it features a single rotor with the generator connected to the gas turbine at the "hot" end (Fig A). The 17-stage axial-flow compressor, equipped with modulating inlet guide vanes and having a pressure ratio of about 13:1, is bolted to the turbine section.

The three-stage turbine is of relatively simple design. Its job is to convert energy from the hot pressurized gas exiting the combustion section to mechanical energy (Fig B). The rotor assembly consists primarily of a forward stub shaft, three turbine wheels, two spacer wheels, and the aft stub shaft, which includes the journal for the No. 3 bearing.

Each turbine wheel is separated from the adjacent stage, or stages, by a spacer wheel. The wheel separating the first and second stages is known as the 1-2 spacer, that separating the second and third stages the 2-3 spacer (Fig C). The spacer-wheel faces have radial slots for cooling-air passages; outer surfaces are machined to form labyrinth seals for interstage gas sealing.

Selective positioning of rotor members is performed during assembly to minimize balance corrections of the assembled rotor. Concentricity control is achieved with mating rabbets on the turbine wheels, spacers, and shafts. Rotor components, held in compression by 12 bolts, are cooled by air extracted from the 17th stage of the compressor. This air is used to cool the turbine first- and second-stage buckets, plus the rotor wheels and spacers.

The first-stage buckets rely on forced-air convection cooling in which turbulent air flow is forced through integral cast-in serpentine passages and discharged from holes at the top of the trailing edge of the bucket. Buckets in this row also are coated for corrosion protection. Second-stage buckets are cooled in similar to those in the first stage. Third-stage buckets do not require forced-air cooling. Second- and third-stage buckets have integral tip shrouds that interlock the airfoils to provide vibration damping; they also have seal teeth to reduce leakage flow.

Buckets are attached to the wheel with fir-tree dovetails that fit into matching cutouts in the rim of the turbine wheels. The rotor assembly is arranged to allow bucket replacement without having to unstack the wheels, spacers, and stub-shaft assemblies. Similarly, buckets are selectively positioned such that they can be replaced individually or in sets without having to rebalance the wheel assembly.

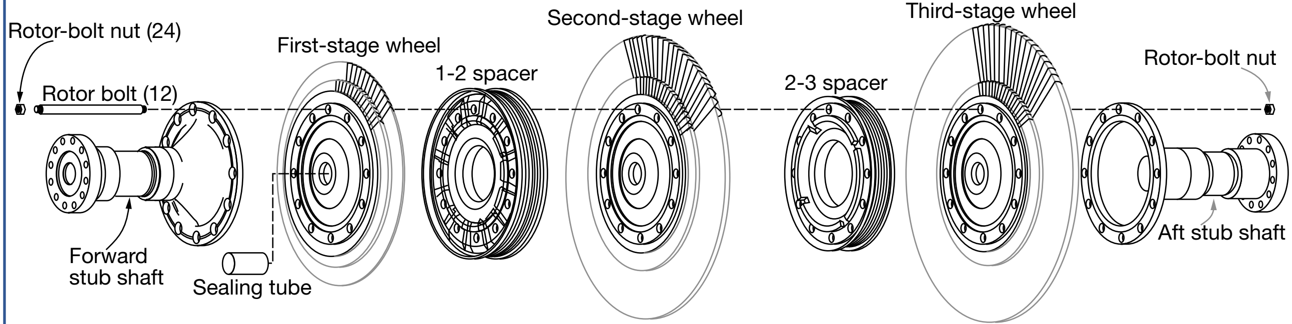
Three stages of turbine nozzles complement the rotating buckets. First- and second-stage nozzles, consisting of 24 segments of two vanes each, are cooled by a combination of film, impingement, and convection cooling. Third-stage nozzle segments number 32 (two vanes in each) and are not cooled.

The turbine shell provides internal support and axial and radial positions of the shrouds and nozzles relative to the turbine buckets. This positioning is critical to GT performance. Borescope ports are provided for inspection of buckets and nozzles.

The exhaust frame is bolted to the aft flange of the turbine shell and consists of outer and inner cylinders interconnected by radial struts. The inner cylinder supports the No. 3 bearing, while the tapered annulus between the outer and inner cylinders forms the axial exhaust diffuser. Cooling of the exhaust frame, No. 3 bearing, and diffuser tunnel is accomplished by independent motor-driven blowers.

A. 7EA rotor is removed from gas turbine for 100,000-hr inspection

B. Combustion section is reassembled following major inspection



C. A relatively simple design characterizes the 7EA rotor—only seven components if you omit the center sealing tube critical for assuring cooling-air flow to the first- and second-stage buckets, and the nuts and bolts

- 1562, stator-vane shim migration (Jan 30, 2007).
- 1854, compressor R2 and R3 tip loss (Aug 27, 2012).
- 1090-2R1, R17 blade movement (Mar 3, 1993).
- 1744, stator-ring rail and CDC hook-fit wear in stages S17, EGV1, and EGV2 (Sept 27, 2010).

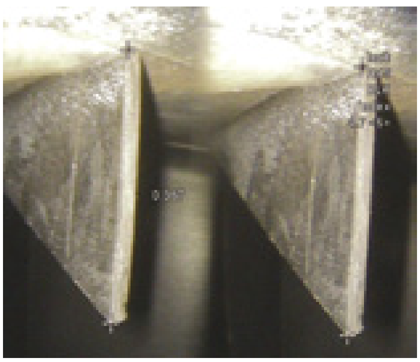
Photos incorporated into Hoogsteden's comments on typical IGV damage, illustrating rubs against the inlet bellmouth and bending of inlet guide vanes, have appeared in CCJ. Shim migration (TIL 1562) also has been discussed extensively over the last several years in the pages of this journal.

Using the Google-like search feature available at www.ccj-oline.com you can find a wealth of information on the subject, including valuable user experience. Hoogsteden gave the group an ATS rule of thumb: When a shim protrudes 250 mils or more into the flow stream (Fig 3), it almost always can be removed. If removal is not possible, the shim is trimmed flush with the stator-vane platform.

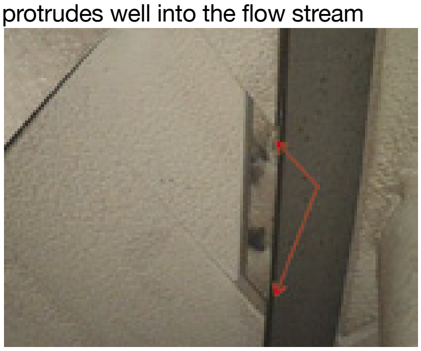
The service manager mentioned that the week prior to the 7EA meeting, an ATS inspection team found ½-in. cracks on two pristine rotor blades—that is, no tip rubs and/or discoloration were in evidence. Hoogsteden said the company's recommendation was to do a dye-penetrant exam during each inspection to monitor crack growth.

Tip grinding is not necessarily the solution, he added, recalling indications of cracking on 18 blades during the first inspection following tip grinding of that blade row in the shop. A red-dye check adds only a little time to a regular borescope inspection because all R1 and R2 compressor blades, and about 85% of the R3 blades can be accessed in-situ.

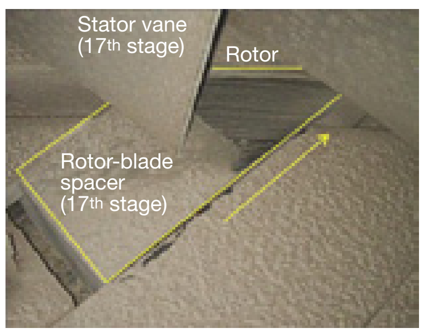
Regarding TIL 1090-2R1, Hoogsteden said the biggest concern is how much the R17 rotor blade is moving forward. A few days before the service manager addressed the 7EA users, an ATS inspector reported that upstream movement of an R17 rotor blade spacer allowed it to contact the rotor, despite double staking. Blade and spacer movement shown in Figs 4 and 5 was 100 mils; maximum allowed is 10 mils.



3. S1 stator shim located at vane segments 1-2 (right side, upper casing) protrudes well into the flow stream



4. Upstream movement of compressor stage 17 rotor blade is easy to spot



5. R17 blade spacer moved upstream and contacted the rotor

'Business as usual' controls strategy still works for many users

Gas Turbine Controls Corp's Peter Zinman, participating in a panel focusing on control-system maintenance and upgrades, suggested to owner/operators that they basically had four controls strategies to choose from: Upgrade to the OEM's latest system, upgrade to Ovation™, replace the turbine, do nothing. There's at least one other retrofit option, of course, a PLC-based controls solution, but it was not included in this session.

Gas turbine reliability is everything: If you don't start, you don't get paid. The safe bet for a 7EA owner is upgrading to the Mark VIe, but that's the most expensive option and probably unaffordable for most plants. Upgrading to Ovation is less expensive, the editors have been told by users, and that has become a popular solution even for some Frame 5 owners.

Replacing the turbine probably is unrealistic given the cost and the permitting challenges. Doing nothing obviously is the least-cost option and viable only if the engine starts when you push the button. The task facing three of the four panelists was to convince attendees that there was a supply-chain network to support a "do nothing" philosophy. And they did that well.

With the OEM having had the entire first day of the meeting on an exclusive basis to capture hearts and minds, there was no need for a GE participant on the panel. Emerson Process Management's Ovation product line was represented by Patrick Nolan, director of gas turbine solutions, and well known to many in the room. Zinman's company, and Randy Riggs' PowerGenics, offer overnight delivery of replacement control system cards from their extensive warehouses as well as the capability to repair failed cards.

CEO John Downing's Turbine Controls & Excitation Group Inc represented the field-service community—the hands-on experts who do the troubleshooting, repairs, upgrades, and enhancements required to support turbine operation. Other companies providing the same services as Downing's were represented at the Vendor Fair, such as CSE Engineering Inc.

Nolan was the odd man out among the presenters, supporting the idea that a new, modern control system really was in the best interest of owners. NERC's Critical Infrastructure Protection Standards (CIPS) will drive many control retrofits, he said, adding that it will not be acceptable to keep Mark V and earlier systems in service.

Nolan was convincing regarding the relatively simplicity in swapping out control systems. Emerson's approach, he said was to remove the old cabinet and drop into the existing space (in most cases) a new Ovation cabinet, which can be completely pretested in the supplier's manufacturing plant (Figs 6, 7).

New drawings come with the replacement control system, Nolan noted, because accurate documentation is critical for troubleshooting. By new drawings, he meant they go back to the source so the OEM's drawings, which probably were never updated to reflect changes over the years, can be tossed.

The company's policy is to deliver new graphics well in advance of the factory acceptance test so operations personnel can comment and Emerson can make the mods requested before the FAT. A simulator is used during the FAT, the controls expert continued, to mimic actual operation. He discussed the value of simulation in terms of time saved on the conversion of multiple 7EAs at one site from Mark IV, dual fuel, water injection to Ovation.

For those considering control-system replacements, Nolan suggested they think seriously about upgrades which can add considerable value at relatively

2. Handling circuit boards: Dos and don'ts to remember

A large number of repairs received by Gas Turbine Controls Corp are believed the result of a user's mishandling that causes static discharge to the board. This is particularly important because many circuit-board components are sensitive to static electricity. Best practices to assure long life of your boards can be grouped into these three categories:

Reduce environmental static

If possible, and to the extent practical, maintain a heightened level of humidity around the control panel and other areas where boards may be handled.

- Ground your panel. A properly grounded panel helps prevent the buildup of static charges and can dissipate built-up charge from the operator.
- Avoid wearing clothing that easily generates or stores static electricity. Cotton or cotton blends are recommended, synthetic or woolen materials are not.
- Plastic items have the potential for generating a static charge. Keep all plastic and Styrofoam™ items away from any area where circuit boards are handled.

Ground yourself

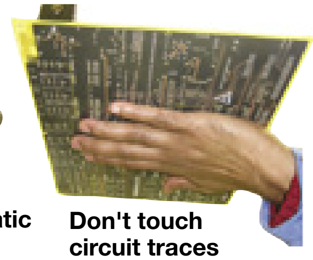
When handling a circuit board, the operator should be properly grounded by (1) wearing a wrist strap connected to a grounding device, or (2) wearing heel grounders while standing on a static dissipative floor surface or mat.

In the absence of either, always discharge any static charge your body might have built up before handling a circuit board. This can be done by touching a grounded metal object—such as a grounded electrical outlet—and holding it for at least two seconds. If your panel is grounded, that will work too. Wearing an antistatic laboratory coat also can reduce the risk of static discharge to the board from clothing.

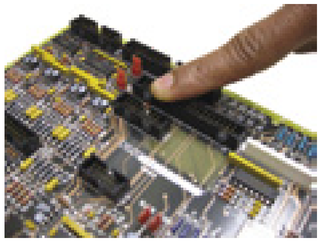
Handle equipment correctly

- Do not touch components, circuit traces, or connectors on a circuit board. Handle circuit boards by their edges. Never hold a card in the horizontal position by one edge; the resulting stress can damage the circuitry.

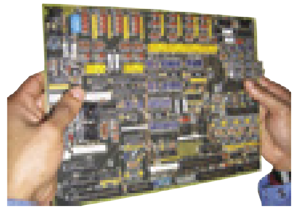
Do wear antistatic wrist strap



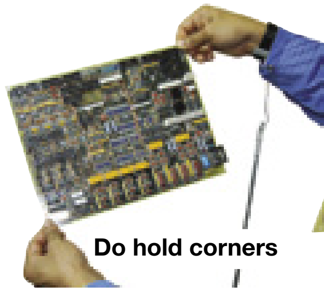
Don't touch circuit traces



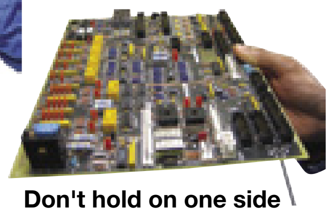
Don't touch connectors



Don't hold inner circuit board



Do hold corners



Don't hold on one side

- After a circuit board or module is removed from a control panel, promptly store it in an antistatic protective bag or box.
- Do not store circuit boards in a stack or adjacent to each other because this also can damage the components.

little cost. Flame detection was one of the upgrades suggested. Legacy systems from a couple of the traditional suppliers of that equipment are oft cited at user-group meetings for reliability issues. By contrast, modern systems, which do not require water cooling, reportedly are very reliable.

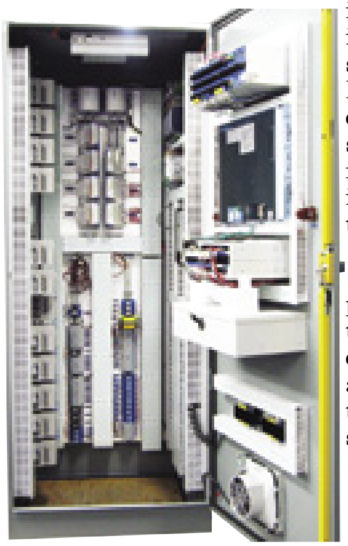
Upgrades for tighter control of NO_x water injection was another suggestion. Generator monitoring is yet another area where upgrades are beneficial because they allow you to deep-six all of the old transmitters and transducers. New vibration controls were recommended as well. Nolan also suggested eliminating the overspeed bolt if installed.

Riggs spoke briefly about PowerGenics' capabilities in the repair and upgrade of control cards for GE gas and steam turbines, focusing on the Mark IV, V, and VI, which are of greatest interest to 7EA users. He mentioned the cards his firm repaired most often, good intelligence for users contemplating spares they might want to have on-hand. Interestingly, the power supplies for the Mark V and VI were the top concerns for those control systems. Overspeed-trip cards for the Mark V also were said to be failure-prone.

The repair expert suggested to attendees that they look for cracks in resistors when they're inspecting and troubleshooting power supplies. If you find cracks, he said, change-out the power supply and have the one removed repaired—because it will fail, it's only a matter of time.

Analyses by PowerGenics of repairs made to power supplies suggests that cycling and overload conditions, plus heat and airborne dirt, are among the primary causes of stresses that contribute to their failure.

Another troubleshooting tip: Cards get noisy before they fail. Replace quickly, Riggs continued, because they can contribute to the failure of other cards—a cascade effect of sorts. One of



6, 7. Relatively easy to remove an existing control panel in most cases (left) and drop in a replacement (right) the biggest troubleshooting challenges, he said, were intermittent faults that go away before you can find them.

PowerGenics technicians maintain detailed records on all repairs. This information enables the company to prioritize the causes of failures and to identify weaknesses in components used in the manufacture of the original control cards. Marginal components are replaced with more robust offerings during the repair cycle making refurbished replacement cards better than the original—at least in some cases.

Zinman was prepared to say much more than he did, but because Gas Turbine Controls and PowerGenics do many of the same things, he spared the owner/operators repetition. He did drive home the fact that the "do nothing" option for owners regarding controls benefitted plants with experienced I&E techs or access to them through a third-party services firm.

The cons associated with a controls upgrade, Zinman said, include the possibility of an extended outage, training of personnel unfamiliar with the new system, operational risks following recommissioning, high cost compared to doing nothing, purchasing new spares, and the sale or disposal of old parts with no use at the plant upgraded.

A few years ago, Zinman presented at the 7EA Users Group meeting on the dos and don'ts in the handling and storage of circuit boards. This material is as valuable today as it was when first presented, and given the large number of first-timers at the 2012 meeting, is worth reviewing (Sidebar 2).

Downing didn't miss a beat while roaring through a presentation on Mark V troubleshooting basics, best practices, and lessons learned. Ex-navy and a former field engineer for the OEM, he left no doubt regarding his deep knowledge and experience. Everyone in attendance with responsibility for a Mark V benefitted tremendously; the editors were among those left in the dust right out of the gate. Among the suggestions made by Downing that the editors could get their arms around included the following:

- Know were all your instruction books are and use them.
- Replace cards with the panel energized, when possible. Before powering-down a cabinet, know what will happen. For example, you lose turning gear and emergency equipment. Also, anyone in the turbine compartment will hear equipment making unfamiliar sounds; the entire plant staff should be informed before de-energizing a panel.
- TMR (triple modular redundancy) is a buzz acronym that the OEM likes to use. It sounds important and leads some owner/operators to believe that their control system is of the highest reliability and essentially failure-resistant. Not! The cabinet is TMR, but not all the devices. In fact, relatively few devices—perhaps as few as 5%—are truly redundant.
- Control cabinets are much like closets. Close the door and everything seems in order. At some plants nothing could be further from the truth, dirt and loose wires abound. Periodic "clean and inspects" are necessary. Every year or two, site technicians should vacuum inside cabinets, tighten connections, conduct necessary calibrations (read the instruction book). Such work enables plant personnel to get (or remain) familiar with system components. This pays dividends when problems surface: Experts can walk knowledgeable plant technicians through the system by phone in many cases, saving time and money.
- A rule of thumb: Recalibrations of control components can deliver as much as a 1% increase in turbine output.
- Install fuses, where possible, to protect circuit cards. A $1 item is all it takes to protect a $5K circuit card from some failure mechanisms. Most of the work can be done with the unit online; final connections, which should take no more than

about two days, are made during the next outage.

The take-away. The presentations by Zinman, Riggs, and Downing were complementary, creating in the minds of attendees that a tight network of reliable third-party equipment and services providers was only a phone call away when problems surfaced with legacy GE control systems. If PowerGenics doesn't have a card a customer needs, Riggs calls Zinman—and vice versa. If Zinman doesn't have field service personnel available for a particular assignment, he calls Downing. And if Downing doesn't have control cards for a project his firm is hired to do, he calls Riggs and/or Zinman. The bottom line: These competitors, at least, believe the customer's needs come first.

Metallurgy that translates to a stronger bottom line

Plant directors, operations managers, maintenance managers, and plant engineers rank high among Planet Earth's most time-challenged professionals. They are expected to run their minimally staffed facilities at top efficiency and reliability without violating emissions permits—all while protecting personnel from injury, dealing with an endless tsunami of corporate and regulatory paperwork, reducing expenses, planning the next outage, etc. Plus, they have to grow in their jobs and learn new technologies—metallurgy, chemistry, cybersecurity, etc—to assure continued success.

The editors often are asked about the value proposition of user groups, some narrow-minded executives believing they're merely an excuse to miss a week's work. Nothing could be further from the truth. They are venues for professional growth with a payback for employers many times the cost of the registration fee, plane ticket, and hotel.

Case in point: The 7EA Users Group, helped owner/operators come up to speed on the role played by metallurgy in making better decisions regarding the repair of gas-turbine hot parts. Who at your plant can look at a photomicrograph and understand the condition of the material and whether it can be restored to operational health? Probably no one—and that's fine. But someone has to know the lingo and enough about the subject so the experts can be asked the proper questions, their answers evaluated, and decisions made.

Liburdi Turbine Services' Lloyd Cooke was selected by the steering committee to provide a backgrounder on both metallurgical analysis and deterioration mechanisms that affect gas-turbine hot parts and then to explain how plant personnel should use the findings of component assessments to guide remedial/preventive action.

Cooke, who speaks technology in plain English, began by making the users aware of the incentives for maximizing component lives, reliably, through informed metallurgical analysis. Aside from fuel, he said, component life-cycle costs are the most significant gas-turbine O&M expense—and hot-section components are at the top of that list. Single sets of components—buckets or nozzles in the case of GE machines—can run from about $800,000 to $2 million per set.

Development of the optimal maintenance program to suit your plant's specific requirements requires the answers to many questions, Cooke continued, including these:

- Is the component repairable by conventional means?
- What repairs should be completed to assure continued service?
- Are there modifications/upgrades better suited to the engine's operating conditions—such as addition of a coating or a coating change?

- Are there engine issues that should be known and/or corrected?
- Can the service interval be extended?
- Is the service duty experienced by the parts going to change?
- How can hours and starts be related to fundamental material changes and measurements of degradation?

Metallurgical life analysis of hot-section parts goes beyond the science of metallurgy, Cooke explained. It requires information on the component's operating history, knowledge of service conditions expected in the future, dimensional data, and findings from nondestructive tests—in addition to the results from the destructive examination of samples removed from specific areas of interest, microscopic examination, chemical analysis, and mechanical testing. These data are analyzed by experts to do the following:

- Gauge repairability and define the repair processes.
- Minimize the risk of otherwise undetectable damage.
- Evaluate coating performance/selection specific to your plant's needs.
- Provide indications of abnormal/detrimental engine operating conditions.
- Assess the potential for extending the service interval.
- Validate repair processes and/or design improvements.

Next, Cooke dug into the causes of base-metal deterioration—such as alloy ageing, creep damage, and the formation of topologically close-packed phases (don't get derailed by the jargon)—moving from there to bucket tip oxidation (material loss), thermal-mechanical fatigue damage, etc. Several slides that followed were dedicated to metallurgical analysis of coatings—including discussion of the most common degradation mechanisms, oxidation, and corrosion.

Damage to internal surfaces of buckets (both coated and uncoated) was next and very important, Cooke said, adding that internal damage can eliminate the option of repairing parts. Destructive metallurgical analysis of a representative sample from the set is necessary to determine the extent of internal damage and if continued service is possible. "Make metallurgical analysis part of your maintenance program," published in the 2Q/2011 CCJ, covered most of the points Cooke made in his presentation and is recommended for follow-on reading (access via the Internet using the search function at www.ccj-online.com).

The hot-parts refurbishment expert concluded his presentation with several performance improvement mods for users to consider, among them:

- Consider first-stage bucket tip extensions as an alternative to replacing shroud blocks with the OEM's low-profile shroud clearance mod. Liburdi claims a 500-kW increase for this enhancement.
- Reduce tip clearance with a MCrAlY high-porosity top coat on uncooled shroud blocks. The coating is abradable and oxidation resistant.
- Cutter-tooth upgrade. Friction between the rail/cutter tooth is conducive to high temperatures that allow transfer of rail material to the honeycomb. Result is rail disintegration. The OEM's cutter tooth is cast into the buckets as new, meaning it is the same nickel-based alloy as the bucket. The upgrade is Stellite hard-face weld alloy.
- Combustor material upgrade. Substituting Nimonic 263 for Hastalloy X can increase high-temperature strength. Plus, Class C TBC (thermal barrier coating) increases thermal protection without sacrificing thermal strain.

With lunch approaching, Cooke left the podium asking users to evaluate rigorously the hot-section component life-extension alternatives he presented. Comparing the service lives and performance of enhanced components to the OEM's data presented in its document GER 3620, he said, Liburdi believes owners can save upwards of $12 million over 20 years.

GTs, like people, sag with age

When Paul Bruning stepped to the podium to share recent overhaul experiences, it had been five years since he last attended one of the organization's meetings. The former chairman of the group's steering committee recognized only a handful of the nearly 120 users facing him and he was surprised. So, before starting his presentation, Bruning asked the audience how many owner/operators were attending for the first time. By show of hands, it was more than half of the participants. That's turnover with an exclamation point.

Bruning chaired the user group for three years while he managed the Sumas Power Plant, a 1 ×1 7EA-powered combined-cycle cogeneration facility that provided steam to a Washington mill for drying lumber. When his employer, Calpine Corp, was forced into bankruptcy, Bruning moved to Puget Sound Energy (PSE) in Bellevue, Wash, as supervisor of thermal engineering.

At that time, the utility was perhaps known best for its hydro assets. But it did have several legacy Frame 7 gas turbines, which were the subject of Bruning's presentation. In the last several years, Puget has added substantially to its thermal fleet by purchasing both peaking gas turbines and combined cycles—including Sumas.

PSE owns four dual-fuel 7Es—all installed in 1981 and each capable of producing 80 MW within 10 minutes after starting. Two units are at the Whitehorn Power Plant in Blaine, Wash, on the Canadian border, two at the Frederickson Power Plant in Tacoma.

Major inspections were performed on the Frederickson units in 2010 and 2011. At the time of the inspections, each unit had logged approximately 18,000 fired hours and 900 starts since COD. Service duty was characterized as peaking and spinning reserve. Water injection for NO_x control was heavy—about 90 gpm per unit.

The majors on Frederickson Units 1, conducted first, and 2 included the following tasks:

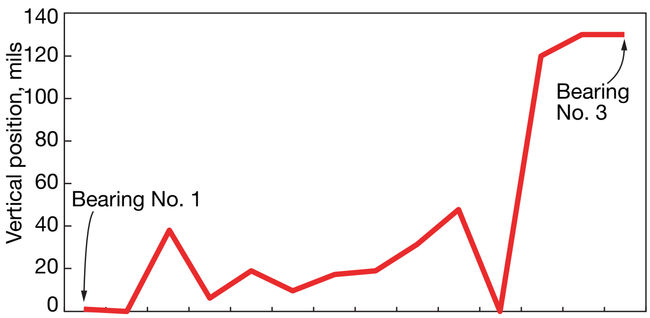
- Disassembly of the gas turbine, generator, and auxiliaries.
- Replacement of compressor blading.
- Replacement or refurbishment of hot-gas-path components.
- Implementation of outstanding TILs.
- Refurbishment of most balance-of-plant components.
- Generator inspection, replacement of retaining rings, rewedging of stator coils, and reblocking and tying of end windings.
- Replacement of the exhaust system.

High bearing vibration levels were experienced by Unit 1 on restart following the major. The third-party services firm that did the major huddled with the OEM regarding the issue and both agreed that misalignment was the likely cause. Unit 1 was reopened under warranty and its alignment checked by Cascade Machinery Vibration Solutions, specialists in this type of work. The compressor discharge casing (CDC) was found to be low and the No. 3 bearing high (Fig 8).

The contractor that conducted the major raised No. 2 bearing and lowered the No. 3 bearing to bring them in alignment with the machine axis. Vibration levels after reassembly were acceptable although the as-left alignment was a compromise given the age of the unit, the time available, and budget considerations. Cascade Machinery's Troy Broussard was on the program later in the day and explained to the users how the alignment was done.

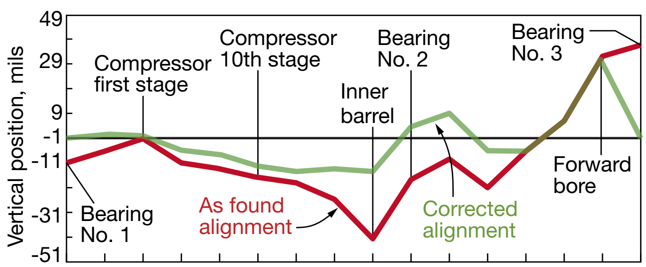
Bruning, joined at the podium by Evan Sorrel, Frederickson's O&M Supervisor, said no one expected casing alignment to be a problem. It was not checked on the two Whitehorn units during majors on those engines before the Frederickson work began and vibration was within spec on restart.

Wear and tear of compressor blades



8. Bearing No. 1 (front of unit) is at left in this vertical position plot showing as-found alignment of PSE's Fredrickson Unit 1; position of bearing No. 3 is at far right. The compressor discharge casing and nozzle support ring were low while bearing No. 3 was high. The CDC and bearings were realigned

9. Corrosion of compressor airfoils convinced PSE engineers to replace compressor blades



10. Vertical position plot for Fredrickson Unit 2 compares the as-found alignment with the corrected alignment. As-found location of the inner barrel was 79 mils lower than Bearing No. 3; corrected difference was only 14 mils

at Whitehorn, plus corrosion of Frederickson compressor airfoils (Fig 9), convinced PSE to replace compressor blades at the Tacoma facility.

During its three decades of service, the Frederickson gas turbines had long periods of inactivity; more recently, the units had experienced tough service, starting twice on some days. One of the twice-daily starts often involved loading to 4 or 5 MW, followed by shut down.

The OEM conducted the major on Unit 2 the following year and its recommendations in TIL 1819, which concerns slippage at flange between the turbine shell and exhaust frame, triggered an alignment check (Fig 10). Slippage between the bellmouth and compressor case also was investigated. Alignment was corrected by the OEM this way:

- Inlet bellmouth, inner barrel, and CDC were raised.
- No. 3 bearing was lowered and moved slightly to the right.
- As-left alignment, although not within specs for a new unit, was approved by the OEM as appropriate for a unit of this age—as it was for Unit 1.
- Vibration levels have been low since completion of work. CCJ

Impossible to pack more knowledge into four days

Setting the stage for CTOTF's 38th annual Spring Turbine Users Conference and Trade Show, April 7-11 in Myrtle Beach, SC, a confident Bob Kirn of TVA, the group's chairman, told the editors "the role of natural gas in electricity generation will continue to expand as nuclear languishes under extraordinary costs, coal remains the environmental villain, and the proven reserves of natural gas continue to increase."


Kirn

He added that after factoring in high-cost renewables of questionable reliability, the complexities of grid operation in an era of must-take intermittent resources, looming CO_2 emissions limits, increased regulation, and today's dramatic load profiles, gas turbines and their owner/operators find themselves center stage, required to provide and sustain ever higher standards of performance.

CTOTF's meetings and digital resources have evolved with the changing information needs of users. Subject matter incorporated into the group's semiannual conferences goes well beyond the gas-turbine enclosure. All equipment and systems required by simple-cycle, cogeneration, and combined-cycle plants powered by GTs are covered, and related industry, management, and regulatory topics addressed. On the equipment side this includes everything from the air inlet house to the high-voltage connection to the grid.

Attendance at the meeting in Myrtle Beach, Kirn assured, will bring you up to date on methods and technologies for improving performance, reducing emissions, and stretching the O&M budget, as well as alerting you to emerging issues that require attention.

Achieving better plant performance at lower cost is an elusive goal, he said, one that depends significantly on the availability of high-quality technical expertise. However, with the trend to flatter and leaner organizations, the in-house availability of expertise to support increasingly diverse technical needs has steadily diminished.

This is where CTOTF provides a huge value-add, Kirn continued. "We serve as your 'extended technical services department'." Heart of the four-day spring meeting is a dozen interactive user-only sessions totaling 64 hours of presentation and discussion time—plus these special events under the CTOTF umbrella:

- Presentation on Monday, April 8, of the 2013 Best Practices Awards recognizing the valuable contributions made by plant staffs—and headquarters personnel—in improving the performance of generating facilities powered by gas turbines.

  Attendance gives first industry access to this information. Implementing at your plant just one or two ideas from this year's record number of entries is sure to pay a 10-fold return on registration/travel/hotel expenses. Note no mention of food: Wickey Elmo, president, Goose Creek Systems Inc, Indian Trail, NC, which manages CTOTF activities, provides all meals.
- A trade show involving nearly six dozen companies providing equipment and services to generating stations will be held Monday, April 8, from 5 pm to 9. Dinner included. Exhibitors include the CTOTF Super Champions and Champions identified in Sidebar 1.
- CT-Tech™, an additional training opportunity offered by CTOTF, this spring provides expanded instruction on fabric expansion joints, Wednesday evening (April 10) from 5:15 until 8. Dinner included. EagleBurgmann's Mike Green will cover the following topics, among others: structure and function, selection of materials, inspection of joints, advantages of fabric over alternatives.

Visit www.ctotf.org for program details, including abstracts of presentations and biographies of guest speakers, registration information, and direct access to the conference hotel.

A robust website is critical to the success of every user group. Relatively few owner/operators can get to meetings on a regular basis, many being tied to their respective facilities because staffing is thin and there's

1. CTOTF's top vendor supporters for 2013

Super Champions

Allied Power Group LLC
Combustion Parts Inc
Dresser-Rand Turbine Technology Services
EagleBurgmann Industries LP
Hy-Pro Filtration
NAES Corp
National Electric Coil
ProEnergy Services
PSM—an Alstom company
Sulzer Turbo Services Houston Inc
TDC Filter—a Midwesco® company
Universal Plant Services
Young & Franklin Inc

Champions

AAF International
ACT Independent Turbo Services Inc
Advanced Turbine Support LLC
Eugen Arnold GmbH
Aviation, Power & Marine Inc (ap+m)
Braden Manufacturing LLC
Donaldson Company Inc
Eta Technologies LLC
W L Gore & Associates Inc
Liburdi Turbine Services
Pratt & Whitney
Siemens Energy Inc
SPX Flow Technology USA Inc
TRS Services LLC
Veracity Technology Solutions

no backup of personnel resources. The CTOTF Leadership Committee understands this reality and reaches out to virtually all GT users via www.ctotf.org. Recall that this organization directly serves owner/operators of Siemens, Mitsubishi, Pratt & Whitney, Alstom, Solar, and GE engines—both aeros and frames.

The CTOTF organization chart offers a capsule summary of subject matter addressed by the group, as well as the industry experts responsible for coverage of those areas. Access the org chart at ctotf.org and click on the person's name for an abbreviated professional resume. Have a question regarding upcoming content, an idea for a presentation, etc? Use the handy email feature.

The group's bulletin board was created by Michael Elmo of Goose Creek Systems, who has extensive experience in the development and implementation of computer-based information systems—including nearly two decades of service with EPRI.

What sets CTOTF's bulletin board apart from most others hosted by the model-specific user groups is that access is available *free* to employees of any company with an equity interest in, or currently operating, *any* type of gas turbine. Register today, Kirn urged, and join the nearly 1000 owner/operators already participating in the CTOTF forum and also gain access to the organization's library of more than 400 presentations from past meetings (Sidebar 2).

Industry issues

The Industry Issues Roundtable provided an adrenaline rush that launched the 2012 Fall Turbine Users Conference and Trade Show (San Diego, September 16-20) in high gear. The opening panel, which explored the challenges electric generators faced in meeting the needs of ISOs, ignited a vibrant exchange that suggested the nation's grid operators may have unrealistic expectations in terms of implementation schedules for their initiatives and the associated costs.

Ozzie Lomax, manager of gas turbine and renewable generation for AmerenMissouri, chaired the panel of subject-matter experts who collectively had nearly a century and a half of industry experience. The participants were:

- David Timson, account manager, CalISO Customer Service and Stakeholder Affairs.
- Eddie Mims, VP of O&M, Colectric Partners Inc.
- Bruce Rising, strategic business manager, Siemens Energy Inc.
- Donald Schubert, senior VP, Marsh Energy Practice.

Timson's opening remarks, tightly scripted, reflected California's challenging energy-supply and environmental statutes which many in the room believed unrealistic. The CalISO's mission is to ensure the reliability of the state's electric system, no easy task. It needs flexible capacity resources—fast start, load following, standby generation, etc—to accommodate the state's mandate of 33% renewables generation by 2020. Regarding existing generation that does not meet the ISO's goals, the attitude is "retrofit, repower, or retire."


Mims


Rising


Schubert

Timson didn't flinch when asked if the San Onofre Nuclear Generating Station would return to service. He said almost casually that the ISO was planning to meeting 2013 summer requirements without SONGS. Converting the units at Huntington Beach to synchronous condensers would help the system get by without the nuclear plant.

In answering a second question, Timson said he didn't think that gas turbines installed in the last 10 years would have a problem meeting the grid's flexible capacity requirements. He also didn't see California's law eliminating once-through cooling at ocean sites as an impediment to the grid's objectives. Timson added that another of CalISO's objectives is to compensate generators fairly. A few attendees having experience with ISOs in other parts of the country chuckled.

Rising mentioned that fast-start engines were developed before renewables integration achieved headline status. He said that the OEMs were sensitive to the need for generators to get units into service with minimum emissions and fast starts were critical to that goal.

Rising also shared the following: The highest power bills in the US are in areas with greatest renewables penetration. Further, the average electric bill has increased every year—even with lower gas prices—except for 2009. Attendees with grey hair recalled that for decades the price of electricity decreased year over year, low-cost electricity being the driver for this nation's economic success.

Mims, who has been around gas turbines for most of his four decades in the industry, spoke about the success of a fast-start/fast-ramp (30 MW/min) conversion project in 2009 at one of the 2 × 1 F-class combined cycles in his company's portfolio.

This plant was making over 300 starts on an annual basis when the successful upgrade was implemented and Mims reported that there have been no adverse effects. Regular borescope inspections attest to good equipment condition, he said. The combined cycle can drop to 50% load at night while maintaining emissions compliance.

Plan is to upgrade the company's dual-fuel 7FA peakers to fast start as well. This upgrade can be completed during a hot-gas-path inspection but will require eliminating oil capability.

Insurers, however, generally are not enamored of fast starts when they involve "older" combined-cycle plants. "Old" in the insurers' lexicon, Schubert told the group, is five or six years. This means upgrades would be required by all plants built during the "bubble" to gain favor with insurers. Perhaps the CalISO did not talk to the insurance community before formulating its opinion of what's realistic and what's not.

Money is not the only consideration here. You may have to convince the

2. How to access CTOTF presentations

CTOTF has added the available presentations from its recent Fall Turbine Forum to the user group's library at www.ctotf.org, which is arranged in chronological order by meeting (most recent first). If you don't already have a "library card" and you are a gas-turbine owner or operator, click on the "CTOTF IBBCS" button on the left-hand toolbar on the home page. Then complete and submit the online sign-up form.

Confirmation of your acceptance as a CTOTF member with full IBBCS (Internet Bulletin Board Communications Service) privileges generally will be e-mailed to you within 72 hours. As a member, return to www.ctotf.org and click once again on the "CTOTF IBBCS" button and proceed to the IBBCS Website. Next, scroll down the page to "Presentation Library" and click on that link.

insurance company that the upgrades you're planning actually will deliver on their promise. Perhaps as many as one-third of the equipment rerates, according to insurance industry statistics, do not meet expectations; in some cases, they have caused failures that insurers have been asked to pay for. And pay insurers have—reportedly $1.12 for every premium dollar received.

Insurers also are not comfortable with combined cycles "chasing" wind, Schubert said. They have concerns about grid stability and its impact on generation—particularly where grid infrastructure is old. Expect your insurer to add restrictive language at the next policy renewal if renewables integration is part of your operating profile.

Other important points made by Schubert were these:

- The desire for business interruption insurance can open Pandora's Box for an evaluation of regulatory, grid, and other issues.
- Three carriers have reinstituted fuel-quality clauses in their policies. This means that if problems with fuel quality cause damage to your equipment, you're not covered.
- T&D coverage is very difficult to obtain; virtually impossible if you don't own the infrastructure. Equipment age and condition are the main reasons for the negative view.
- Transformer losses continue to mount, particularly for units rated 400 MVA and above.
- Insurers favor machines equipped with condition- and performance-based monitoring systems. Plants with staffs backed up by expertise at an M&D center get high marks from insurers.

To hold insurance costs in check, owners may have to raise their deductibles—that is, assume more risk in case of an accident. Mims didn't see this as a problem for companies with highly experienced asset-management personnel. Tight control of repairs is critical, he said. Track and examine all parts with a fine eye.

One measure of repair quality is fallout. As an example, Mims said, you might have a goal of 3% fallout or less on the first repair, 5% maximum on the second, and 10% max on the third for a well-operated and –maintained peaker. The percentages would be higher for gas turbines serving a base-load combined cycle because average operating temperatures are higher than they are for peaking units.

Since California was the regional focal point of the discussion, the panel could not be discharged at the coffee break without mention of how emissions might be impacted by ISO decisions. Rising, who spent the early part of his career developing and designing combustion and emissions control systems, took the lead here. For CO_2 emissions, he said, EPA has announced 1000 lb/MWh as the emissions limit for power generators in proposed federal New Source Performance Standards.

Rising thinks the agency may be over-reaching on this point. Even California's rules allow 1100 lb/MWh. While a late-model combined cycle operating at base load might emit only 750 lb of CO_2 for each megawatt-hour of electricity produced, he continued, unit outputs vary with grid requirements and emissions can increase dramatically as generation is ramped up and down, and turned on and off. A chart of actual operating data showed that 1200 to 1400 lb, on average, was a more reasonable limit based on current operating experience.

Insurance concerns

Marsh's Don Schubert did double duty at the CTOTF fall conference. Following his participation in the opening panel discussion, Schubert gave a sobering presentation on the state of the insurance industry. He is one of very few people who gets applause and gains respect for delivering bad news. An engineering professional with more than 30 years of experience in boiler and machinery insurance, Schubert told attendees that as industry losses continue to mount insurance premiums and deductibles would continue to climb. This year premiums increased by up to 18%.

Insurers are not making money

serving the electric power industry today, he said, paying out $1.12 for every dollar received in premiums. Losses exceeding $100 million are occurring with increasing frequency and business interruption coverage is costing carriers big bucks. There are now about a dozen and a half insurance companies serving this market sector worldwide, two fewer than there were only recently.

In the last six to nine months, Schubert added, deductibles and captive numbers have increased dramatically. For example, deductibles for plants with a poor history have jumped in some cases from a nominal $5 million to $10 to $20 million. In addition, the primary captive layer for generating companies has gone from a typical $8 million annual aggregate ($4 million per occurrence) to $20 million or so, with one company said to be at $50 million. This means the onus is on the plant manager to protect the company's captive layer.

It's important to recognize that insurers are limited in their ability to control losses: They cannot tell you how to run your plant. Their only options are to increase your cost of insurance, change your coverage, limit their liability through restrictions, and not renew your policy. Restrictions might be limits on downstream damage, a requirement to use OEM parts, limits on starting time and ramp rates, etc.

Schubert presented a chart of property-loss experience for 2011 that revealed industrial frame engines accounted for 28% of the losses in plants powered by gas turbines, down from 36% at the height of the bubble (Fig 1). Transformer losses have increased significantly over the last five years, he said, while other percentages have remained about the same over that period of time. There were four significant compressor wrecks last year, but none in the US.

Another slide showed that three-quarters of the losses for plants with GTs occurred following the start of pre-operational testing and that nearly three-quarters of those losses involved people. The insurers' perspective is that the loss of plant-level O&M expertise has been expensive for them. Schubert said that upwards of 4% of a given plant's premium is based on the insurers' perception of how good an operator you are.

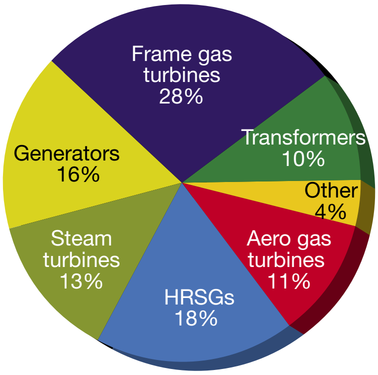
Shifts and changes in technology by the OEMs give insurers concern, Schubert continued. He offered this view of the industry's mindset: "Show me positive operating results for a year on the third machine of a model series and I'll consider an adjustment in risk assessment." Not surprising then is that none of the latest machines offered by the OEMs—such as the H and J classes—are considered "proven technology" by the insurance industry. However, at least one reportedly is close to gaining acceptance.

Periodically, a type of defect may appear without warning in a given fleet of engines at a certain point in the life cycle, or possibly in machines operated in a like manner. The insurance industry is dealing with two of these issues at the moment on models of 50-Hz engines made by different manufacturers.

Insurers will remain concerned until a root-cause analysis is completed and engines throughout the fleet are fixed accordingly. Consider the insurer's position: An OEM may say a given problem has been corrected with a design upgrade, but that doesn't address existing equipment—it still has the flaws.

Schubert next ran through a list of plant-level insurer issues and concerns before moving to lists of specific concerns associated with each of the gas-turbine OEM's machines, and with steam turbines and generators in general. This portion of the program certainly was of great value to attendees looking for guidance on where to invest their maintenance dollars. Sprinkled throughout were photos of equipment losses you might never think possible—such as equipment not clearing underpasses, bridges collapsing because of overloads, rigging failures, etc (Figs 2, 3). Here are a few take-aways from the balance of the presentation:

- Damage from a roll of paper towels left in a gas turbine wound up costing $18 million.
- No dollar value was mentioned for the ladder left in a gas turbine.
- Insurance carriers typically have several levels of coverage for you



1. Insurance data for payouts on fire and boiler and machinery coverage in 2011 show frame gas turbines accounting for 28% of the industry's losses

2. Collapse of a marginal bridge sent this gas turbine into the drink

3. Transformer transit event was the appropriate title for these before/after photos to choose from, the most affordable of which covers only damage to a specific row or component, not downstream damage or issues related to design flaws.

- Insurers are quite concerned about the potential for bolt-type turbine overspeed trip systems to not function as intended because of varnish, sticking, spring failure, etc. Schubert's suggestion: If you still have a bolt, convert to an electronic trip system.
- Use of vibration monitoring and other diagnostic systems equate to lower risk, lower premiums.
- Insurers consider machines installed more than five or six years ago and cycling frequently as failure prone.
- Generators have been problematic recently. The last eight losses had slot movement and end-turn vibration exacerbated by cycling.
- Supply-chain concerns for components such as castings are huge.
- Fire protection systems: Make sure they're up to date and meet all applicable codes—such as NFPA 850.

O&M, business practices

Ron Munson's presentation on the importance of user participation in end-of-life assessments for major components of combined-cycle plants highlighted the O&M and Business Practices session on the afternoon of the first day. Bill O'Brien, VP, Entegra Power Group LLC, chairs that roundtable; Dariusz Rekowski, NV Energy's generation executive, is vice chair.


Munson

Munson, a registered professional engineer, runs the small metallurgical engineering and materials consulting firm that bears his name from offices in Round Rock, Tex.

End-of-life assessments have been a growing business since OEMs announced limits on operating hours and starts for their gas-turbine rotors a few years ago. With gas prices low, engines are running more and many plants are rapidly approaching decision deadlines, recognizing shop times for inspections, overhauls, upgrades, etc, may have to be booked as much as three years in advance.

Relatively few plant managers are familiar with the metallurgy of their equipment and the damage mechanisms that limit component lifetimes. In the time available, Munson helped attendees focus on what was important to know and how not to get tangled up in a sales pitch. With new engine orders down, the OEMs will pushing hard to get this business and it's easy to overspend if you're not careful.

Munson told the group that there are these three general approaches to GT life extension:

- Accept OEM recommendations as gospel and follow their guidelines. This is the lowest-risk alternative and also the most costly.
- Ignore all recommendations and proceed with business as usual. This is the lowest-cost alternative and also the most risky.
- Decide on an acceptable level of risk, define which damage mechanisms can cause a failure, and address only those issues in formulating a life management program.

He then suggested that owner/operators might work together, possibly through a user group, to agglomerate knowledge and challenge the OEM's recommendations. A couple of user groups already are doing this.

One of the most helpful parts of Munson's presentation was the following checklist of parts to evaluate and damage mechanisms of concern:

- Inlet guide vanes: wear, corrosion/erosion, fatigue, mechanical damage (impact).
- Rotor shaft: marriage coupling damage (wear, galling, cracks), bearing journal scoring and rubbing.
- Engine supports: wear, distortion.
- Casings and cylinders: distortion, wear, thermal mechanical fatigue, embrittlement/degradation.
- Exhaust cylinder/manifold: thermal mechanical fatigue, embrittlement/softening, creep/distortion.
- Inlet plenum: corrosion/erosion, mechanical damage (impact).
- Compressor discs: Mechanical fatigue (high- and low-cycle fatigue), wear loss of dimensions, distortion (rim bending in air flow direction), metallurgical ageing (latter stages).
- Turbine discs: creep, metallurgical alteration, blade-root wear, fatigue (especially thermal mechanical fatigue), interference fit between discs and transition pieces.

A summary of OEM and model-specific advisories compiled by Munson serves as a handy reference. Outlined below are some key points that he highlighted.

GE Power & Water

Life limits of Cr-Mo-V turbine rotors. GE TIL 1576 summarizes the company's position for its frame engines. In brief it limits rotor life to 5000 factored starts and run time to 200,000 equivalent operating hours, whichever comes first. Munson's critique:

- Assumes temper embrittlement features of Cr-Mo-V rotors. "Technology transfer" is from the company's steam-turbine knowledge base, which really doesn't relate.
- There are no supporting engineering evaluations, just some dimensionless tables and graphs.
- Does not consider the "goodness" of modern steels as compared to the air-melted steels of older turbines. What's the pedigree of materials? Munson asked rhetorically. Vacuum-melted steels are different than those of the past.

Status report: There have been no known failures to date from a lack of conformance to GE TIL 1576.

Hot-section disc issues on 7FA and 9FA engines. Issues are addressed by various Technical Information Letters: 1539-2, Shot peening (non-contoured); 1540-2, Shot peening (contoured); 1327 and 1434, Eddy current inspection for cracks.

Status report: There have been two catastrophic failures and more than 25 discs have been found with cracks. All cracks are in square cooling-slot profiles.

Life limits on GE LM engines. A 2004 service bulletin covering all LM engines limited the lives of certain components to 50,000 service hours. Tracking of engines by serial numbers began at that time. Discs are not traceable to engine serial numbers, but discs now are tracked by their own SNs. Issues include creep, thermal mechanical fatigue, and metallurgical alteration.

Alstom Power

11N/13N rotor life exhaustion. Rotor life is limited to 130,000 hours because of concerns over (1) creep in the fourth-stage turbine blade root and (2) L-bore cracking, thermal mechanical fatigue, and creep. Recall that the L-bore allows air to pass from the first-stage disc face to cool R1 turbine blades. The company has a program to correct L-bore issues but the solution for fourth-stage creep is rotor replacement.

Status report: There has been no evidence to date of creep damage on rotors having recorded more than 100,000 operating hours. More specifically, there has been no visible plastic deformation or cracking and there have been no eddy current indications. However, there has been some thermal softening on Stage 1 (about 10 to 20 points on the Brinell hardness scale).

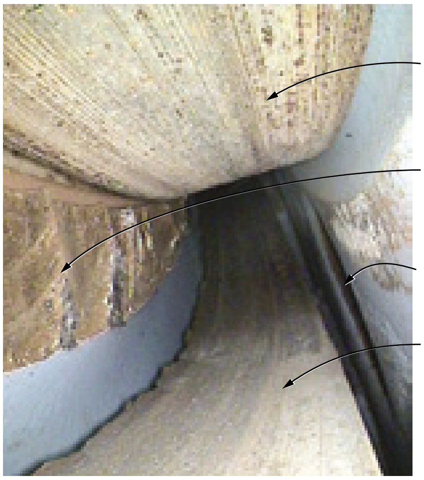
Siemens Energy

Lifetime extension (LTE) program. The Siemens LTE approach is relatively straightforward:

- Evaluate fleet history and identify generic design issues.
- Conduct unit specific evaluations.
- Disassemble the engine and perform detailed NDE and dimensional inspections of component parts.
- Reassemble the engine with existing and/or new parts.

Issues addressed by the LTE program include the following:

- Temper embrittlement of both hot section rotor discs and the last several compressor rotor discs.
- Wear of blade slots, turning gear, and sealing grooves.
- Metallurgical deterioration of the turbine cylinder from graphitization (greatest concern is in the welds and heat-affected zone).
- Thermal mechanical fatigue and creep of turbine discs.
- Wear and distortion of engine supports.
- Ovalization and creep of compressor discs in hot areas.
- Wear, erosion, and/or corrosion in the air inlet.
- Thermal mechanical fatigue, creep, and loss of properties (from ageing) in the exhaust section.



4. Dislocated rabbet material was lodged between the 16th- and 17th-stage discs

Wheel failure

All gas turbines are unique, despite model numbers that might argue otherwise. In engineering school, students were introduced to the bathtub curve—at least they were decades ago. The basic idea was that after a relatively short break-in period component reliability remained virtually constant until end of life, when it dropped off the proverbial cliff.

Most students didn't pay much attention to the word "component" and fewer still probably read the fine print, which talked about the general applicability of the curve to electrical and electronic components, but not to complex systems.

Reliability theory aside, many GT owners believed that "fleet issues" associated with each engine model eventually would be resolved. In many cases they have been, but in others they have not. New problems seem to surface more frequently than one would expect for an ageing fleet, in some instances probably because the design of a given engine continues to evolve.

Example: The thinking by some in the industry is that the clashing of Row 1 and/or Row 2 stationary and rotating blades in many 7EAs could have something to do with the flexing of the casing which may have been thinned by designers over the years, together with the lockup of vanes in their carriers because of rusting.

An incident described by a user at CTOTF's Turbine Users Conference last fall suggests there may be no end to unwelcome surprises for some turbine owner/operators. A dual-fuel, water-injected 7211F commissioned nearly 20 years ago suffered a 16th-stage wheel failure that left most attendees scratching their heads. That this incident occurred after "only" about 1600 starts and 13,000 fired hours might give pause to complaints by some users regarding what they consider unreasonably short rotor lifetime limits imposed by OEMs.

A review of unit history reveals the machine had a turbine-rotor upgrade in the late 1990s and it experienced a17th-stage compressor wheel failure and upgrade to the so-called "bigger, better fillet" (BBF) five or six years ago.

The 16th-stage wheel failure occurred while the unit was being unloaded for shutdown. A vibration trip occurred below 30 MW. It was initiated by a step increase in vibration on the No. 1 and No. 2 turbine bearings, recorded on both seismic and proximity probes. An attempt to restart the unit the next day resulted in an automatic shutdown initiated by high vibration.

A borescope inspection of both the turbine and compressor revealed no problems. Also, no damage was noted external to the rotor after the upper casing was removed. But a subsequent borescope examination with the casing off identified the disc failure at the aft rabbet fit. Specifically, rabbet material was found lodged between the 16th- and 17th-stage discs (Fig 4).

The owner's engineers investigated several options, including a weld repair, which was nixed because of concerns that another component might fail. No spare 7211 or 7221 rotors were available and it was unclear that a 7241 rotor would fit properly in the 7211 casing. In the end, the owner purchased a "robust back end" (RBE) compressor rotor from the OEM. This solution required machining of the distance piece to the reverse gender of the marriage coupling. Other enhancements were made as well.

The conclusion draw by the owner's engineers was that the BBF rotor design is not a permanent solution and users with them should upgrade to the RBE.

Rankine considerations

Wambeke

Scott Wambeke, PE, one the industry's most experienced HRSG troubleshooters, had a simple message for GT owner/operators attending the Combined Cycle Roundtable: Don't opt for a GT upgrade before conducting an engineering evaluation to see if your heat-recovery steam generator will meet expectations with the new operating parameters.

In a marketplace demanding greater operational flexibility to meet evolving and more stringent grid requirements, owners are considering GT enhancements such as compressor and firing-temperature upgrades, plus retrofits to enable operation at a lower minimum load and others to boost peak output. It's important to keep in mind, Wambeke said, that implementation of any of these options will affect the HRSG.

Performance trends. He covered the potential impacts of GT upgrades—including changes in HRSG thermal performance, low-load operating issues, and possible need for a boiler capacity assessment if steam production increases. Regarding thermal performance, Wambeke offered the following insights:

- If exhaust flow increases, expect a nearly proportional increase in steam flow, higher gas-side pressure drop, and a shift in energy absorption to the back end of the unit. The last usually means a slight bump in low-pressure (LP) steam flow and a greater risk of having a steaming economizer.
- A higher exhaust temperature typically translates to a slight increase in steam flow, higher

energy absorption by the superheater and reheater tube bundles, increased attemperator spray-water flow, and usually less LP steam production.

Compressor upgrades usually increase exhaust flow by 2% to 5%, reduce exhaust temperature by 5 to 15 deg F, produce a small net increase in steam flow, and curtail attemperator spray-water flow, Wambeke continued. He also said that firing-temperature upgrades produce little change in exhaust flow, raise exhaust temperature, increase HP steam flow by a small amount, and increase significantly tube metal temperatures and attemperator spray-water flow.

Low-load trouble spots. If exhaust temperature increases at low loads, as it does for GE F-class gas turbines, spray-water requirements may increase dramatically. Wambeke mentioned that a 1200F exhaust spike for a 7F can initiate a spray-to-saturation event (Fig 5).

Control-valve turndown can be an issue, especially when the boiler feedwater pump operates at constant speed. In such cases, valves may have to throttle to 10% to 25% of the full-load rating, increasing wear. Drum-level and attemperator control valves are impacted as well.

For HRSGs operating in the sliding-pressure mode, evaporator-section temperatures will drop as load decreases, the boiler designer said. A low gas temperature at the SCR location will reduce catalyst activity and may lock out the ammonia supply. Also, circulation flows in the LP economizer may change and increase the risk of flow-accelerated corrosion (FAC).

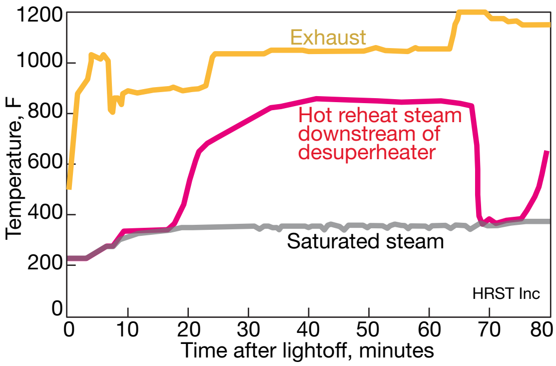
Economizers typically are at a higher risk of steaming with the GT at low load, Wambeke added. Plus, buoyancy instability is exacerbated when water velocity in economizer circuits drops below a minimum value; flow stagnation conducive to fatigue failures can result.

Finally, non-pressure parts—such as liner systems, perforated plates, and anti-vibration supports for tube panels—may fatigue more quickly during low-load operation when gas temperatures are significantly higher than they are at full load.

Capacity assessment. GT upgrades, such as an LM5000 to LM6000 conversion, can increase steam production to where it exceeds the stamped HRSG capacity permitted by the *ASME Boiler and Pressure Vessel Code*. Bear in mind that safety valves must be able to relieve the stated capacity and an exceedance is not permitted. The ASME stamped capacity can be revised, but this must be studied and documented by an organization holding an ASME design stamp prior to recertification, Wambeke told the attendees.

In addition to safety-valve capacity the following components also require review:

- Drum steam separators. Insufficient capacity may result in carryover.
- Reheater and superheater tube metal temperatures. This requires use of a sophisticated heat-transfer model.



5. A 1200F spike in exhaust temperature during startup of a GE F-class engine can initiate a spray-to-saturation event

- Feedwater-pump and control-valve capacity.
- Attemperator capacity.
- Modeling of water flows and velocities in economizers and LP evaporator circuits to determine the risk of FAC damage.

Drowning in paperwork

The tsunami of regulations overwhelming the electric power industry has spawned a mountain of paperwork on every plant manager's desk. While most of the model-specific gas-turbine user groups remain focused on the engine, CTOTF has expanded its coverage, in part to help owner/operators keep up with new regulatory requirements. Implementation of changes in conference content has been rapid and ongoing over the last several years.

A case in point is the Regulatory and Compliance Roundtable chaired by Scott Takinen of APS, a well-respected plant manager who recently moved up to the corporate offices as director of executive projects for fossil generation. Back in 2006, he prevailed upon then CTOTF Chair John Lovelace, an APS colleague, to launch the ZLD (for zero liquid discharge) Roundtable. No one could have imagined where that big first step away from gas turbines would lead.

Recall that in the early 2000s a movement began in California to prevent powerplants from discharging any liquids offsite. Several types of ZLD systems had been installed by the middle of the decade—all expensive and with onerous O&M requirements. Takinen was concerned that the fever might spread to other states and thought CTOTF members should explore the intent of the regulations and learn more about the mitigation technologies.

It didn't take the forward-thinking plant executive long to bring other environmental issues under his roundtable's umbrella. The CTOTF Leadership Committee, chaired by TVA's Kirn following Lovelace's retirement from APS in 2007, voted on Takinen's suggestion to rename the session Environmental Systems and ZLD for the fall 2008 meeting. By then, ZLD furor had begun to subside and discussion of other environmental issues expanded.

Shortly thereafter, the CTOTF leadership recognized that the technologies for reducing air emissions consistent with regulatory requirements were available and generally being addressed by the various gas-turbine roundtables (low-emissions combustors, etc) and by the Combined Cycle Roundtable, which focused on the Rankine cycle. This prompted a repositioning of Takinen's session to encompass all regulatory issues facing owner/operators.

Takinen

The Regulatory and Compliance Roundtable debuted in 2010. The following year, vice chairs specializing in air/water and NERC/FERC regulations were elected. Today those positions are filled by Kimberly Williams of NV Energy and Alan Bull of NAES Corp, respectively, both experts in their fields.

When Takinen talked-up the ZLD Roundtable in 2006, most attendees were left scratching their heads, and the generally persuasive plant executive was hard pressed to get 10 participants in his session. In just a few short years, participation has grown to about one-third, or more, of the conference attendees. And, because subject areas requiring discussion continue to increase, the Regulatory and Compliance Roundtable at upcoming spring meeting will run a full day, up from the traditional four-hour session.

CT-Tech™ is an additional training opportunity offered by the Combustion Turbine Operations Technical Forum™ (**CTOTF™**). **CT-Tech** provides instruction and training in plant operations and design theory on user-identified subjects. Classes are designed to educate not only new plant personnel but also to help experienced engineers and plant personnel refresh their skills and expand their knowledge. A **CT-Tech** class on Fabric Expansion Joints/Bolsters will be taught at the CTOTF Spring Conference by Michael G. Green, General Manager of CTOTF Super Champion EagleBurgmann® Expansion Joint Solutions.

CT-Tech Classes are **free** to pre-registered CTOTF conference attendees.

CTOTF

Spring 2013 Conference
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Alphabet soup

That the Regulatory and Compliance Roundtable provides technical information attendees can put to immediate use at their plants as well as valuable perspective on the direction of both changing and new rules, regulations, and legislation was illustrated by the following lineup at last fall's session:

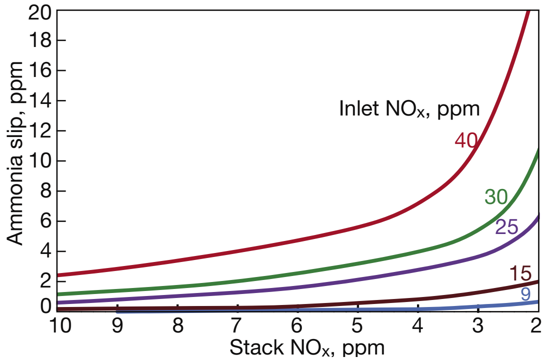
- Mark Haughn of APS addressed NERC-required plant documentation for Critical Infrastructure Protection (CIP).
- Dan Ott, VP of Industrial Catalyst Services at Environex Inc, helped owner/operators get a firm grip on SCR catalyst O&M.
- Julie Mitchell of URS updated attendees on air permitting requirements for new and modified gas turbines.
- Shirley Pearson, PE, of URS spoke on new source performance standards.

Haughn is a full-time member of a six-person team responsible for developing, supporting, and implementing APS' enterprise-wide CIP compliance program. In April 2011 the APS team received the first zero-finding CIP audit conducted by the Western Electricity Coordinating Council. Two of Haughn's other responsibilities: Modernize and make CIP compliant 20 substations and a coal-fired powerplant; conduct CIP training throughout the company. Point of the summary resume: Haughn knows CIP.

A primary objective of his at the CTOTF meeting was to make attendees aware of CIP Version 4's significant impacts before the standard "goes live" Apr 1, 2014. V5 is expected to follow in early 2015. The expert said achieving compliance with V4 will require about 18 months of effort, which means it's a critical-path item right now. He added that the only difference between the current V3 and V4 is CIP-002, "Critical Asset Assessment."

In V3, owners of critical infrastructure conducted their own assessments to determine what a critical asset is. The standard required risk-based assessment methodology. V4 requires a criteria-based assessment and if certain well-defined criteria are met then the asset is a critical one. Example: Every black-start resource identified in the transmission operator's restoration plan is critical.

CIP terms generally don't mean much to most plant personnel at first blush; however, their impact will be a more restrictive life on the deck plates. Plus, there will be more paperwork, more reporting, potentially more cyber and physical security at the plant, additional CIP audit scope, etc.



6. Three key points are in evidence from the series of curves above: (1) The higher the inlet NO_x, the greater ammonia slip, (2) ammonia slip limits stack NO_x, and (3) reducing inlet NO_x can reduce ammonia slip and increase catalyst life

To illustrate the big difference between Versions 3 and 4, Haughn said that the number of devices related to plant operations that come under the compliance umbrella as defined by V3 is 119. Under V4 it will be in the neighborhood of 1500. Also, expect that the compliance costs associated with certification of remote sites will be much more costly under V4 compared to V3.

After reviewing CIP-002, Haughn gave an overview of standards CIP-003 through CIP-009. It included what evidence of compliance is required, at what intervals the evidence must be complied, and how the evidence must be delivered for proof of compliance. In conducting this review, he mentioned that CIPs 004, 5, 6, and 7 accounted for the most write-ups and fines.

Ott

Haughn also covered the filing of Technical Feasiblity Exceptions, as well as self-reports, which document admissions of violations. An overview of training required under the CIP standards and audit evidence requirements closed out the presentation.

Ott, who has an advanced degree in chemical engineering, is known to CTOTF members for his deep knowledge of emissions-control technology. The article developed from his presentation in spring 2008 (CCJ 3Q/2008, "SCR working well? Don't take that for granted") covers some of the same material that he spoke to in San Diego because the basic technology has not changed much but the audience has, with more than 40% of this fall's attendees first-timers. His review of the basics certainly was in order.

What follows are several important points made by Ott which were extracted from the editor's notes. Users have access to the actual presentation via the CTOTF Presentations Library at www.ctotf.org.

- The trend is to less catalyst—just enough for suppliers to meet their guarantees. Some of the early SCR catalyst beds lasted 10 years or more on GTs burning only natural gas. Providing more product than required was adversely impacting supplier balance sheets.
- Fast-start units are expected to require more catalyst than normal-start GTs because the catalyst can't "catch up" with NO_x produced early in the operating cycle, when design operating temperatures have not yet been achieved. More catalyst is required to make an effective "sponge" for the pollutant.
- It is important to monitor SCR inlet NO_x to assure meeting emissions expectations. Ott put up on the screen a series of curves that shows you should be at 15 ppm inlet NO_x if you expect to achieve 2 ppm NO_x at 2% ammonia slip as some regulations require (Fig 6).
- Expect to double NO_x with duct burners wide open as the chart agglomerating data points for an F-class unit reveals. When that happens, ammonia slip will at least double (Fig 7).
- Ammonia slip increases as catalyst ages. Near the end of life slip increases exponentially as catalyst deactivates—so-called ammonia "breakthrough." If your monitoring of ammonia slip reveals a relatively small but increasing value over time, particularly when the catalyst is young, double-check to be sure inlet NO_x is not off-spec. The catalyst may be blameless.
- Monitor pressure drop across the SCR catalyst to check for fouling; monitor ammonia consumption to check for catalyst deterioration, and maldistribution of the reagent. If fouling occurs, it may be caused by fine dust released from the upstream CO catalyst. Cleaning of the SCR catalyst—back blow with air or vacuum—can bring the pressure drop back within spec. Periodic cleaning of CO catalyst also is a good idea.

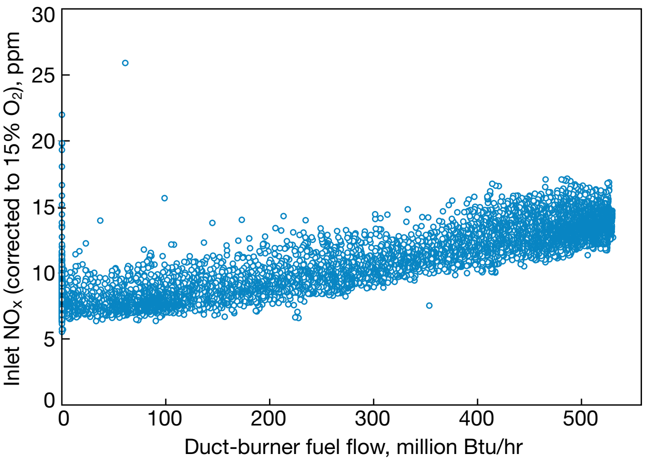
  Plugging of the CO catalyst is one of several reasons for uneven distribution of ammonia across the face of SCR catalyst, and it can contribute to an increase in slip. Ott mentioned a case where cleaning of the CO catalyst lowered ammonia slip at the stack by 2 to 3 ppm.
- Ott urged attendees to write

tight specifications for replacement catalyst and to buy only a top-quality product.

- Tuning of the ammonia grid was included in Ott's presentation, of course. But by the time he got to that part, Takinen, hammer in hand, was ready to hit the gong.

Mitchell's and Pearson's presentations were especially valuable for a plant manager planning to modify an existing unit and not supported by a staff of headquarters engineers that includes one or more environmental experts. The operative word in the first sentence is "modify." Your definition and that of the regulatory authorities—particularly those at the state and local levels—might be miles apart. If want an answer to one or more of the following questions read through both presentations, which are posted to the CTOTF Presentations Library:

- How do the new National Ambient Air Quality Standards (NAAQS) impact planned new units and modifications to existing gas turbines?
- What is the relevant content of the New Source Performance Standards (NSPS) for stationary gas turbines?



7. Expect to double NO_x with duct burners wide open. When that happens, ammonia slip will at least double

- What are the five steps to the Top-Down BACT (Best Available Control Technology) process?
- Must I install the "best available" technology?
- What can I do to eliminate costly or inefficient technologies from further consideration?
- How has the five-step BACT process changed with the addition of greenhouse gases?

The answer to the first question, presented by Mitchell, covered the NAAQS standards for NO_2 and PM2.5, relevant facts on each pollutant, and attainment status. Who is affected, what triggers dispersion modeling analysis, analysis methodologies for the pollutants, and other relevant topics were reviewed by the speaker.

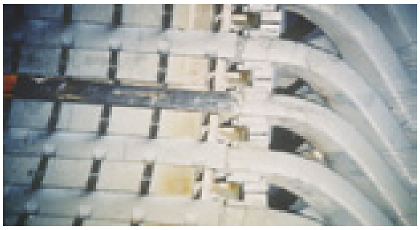
Mitchell also provided case histories of two projects struggling to show compliance and answered the question no one wants to hear: What if *significant impacts* are predicted by modeling? Another valuable part of the presentation was a reference list of important EPA documents covering the main topics Mitchell discussed.

Pearson addressed the remaining questions. Her slides provide considerable detail and are easy to follow.

Generators

When Don Schubert, senior VP of Marsh Energy Practice, told participants in the opening session of the CTOTF fall meeting that generators accounted for 16% of insurance losses in 2011, there was a look of disbelief on some faces. The reliability of generators typically has been "taken for granted" by the industry. But eight generator losses last year, attributed

8. Stator rewind cost nearly $5 million; the business-interruption payout was five times that amount



9. Simple bar failures took this machine out of service for eight weeks

10. Rotor rewind cost power producer a 56-day outage and the insurance company megabucks including more than $7 million just to repair the physical damage

primarily to slot movement and endturn vibration exacerbated by cycling, point to the need for closer attention by plant operating staffs (Figs 8-10).

Generator reliability has been decreasing over the years for several reasons, among them:

- Tighter design margins. Someone pointed out in the open discussion that back in the 1930s generators weighed six times what they do now on a kilovolt-ampere basis. Today's design tools contributed significantly and positively to the reduction in bulk. However, the goal of ever tighter design margins often is driven by customers wanting to pay less for their equipment. "Be careful what you wish for" applies here.
- Loss of continuity in OEM engineering expertise. Some of the generator issues in evidence today were identified years ago—back in the 1940s, 1950s, and 1960s—and corrected by design engineers. But during the transition to leaner OEM staffs in the 1980s, some top managers were more concerned about immediate reductions in "head count" than about focusing on retaining the company's knowledge and ability to compete in the future.

  The result: Some of yesterday's problems have resurfaced and must be re-solved. Access to retired OEM generator engineers may be one of the reasons several third-party generator inspection and repair companies, and consultants, have been quite successful of late.
- Transition from a regulated to a deregulated electric-power market. Electric utilities are (or at least used to be) deep in electrical engineering talent to keep a watchful eye on generators, transformers, and high-voltage (HV) switchgear. By contrast, most independent producers have a few (in some cases only one or two) overloaded engineers assigned to those duties. Further, parsimonious staffing at independent powerplants, and a general reluctance of deck-plates personnel to approach unfamiliar HV equipment that hums, sparks, and arcs, often leaves generators without a staff champion.
- Higher ratings—kV and kVA—for air-cooled generators are challenging today's perceived technology limits.

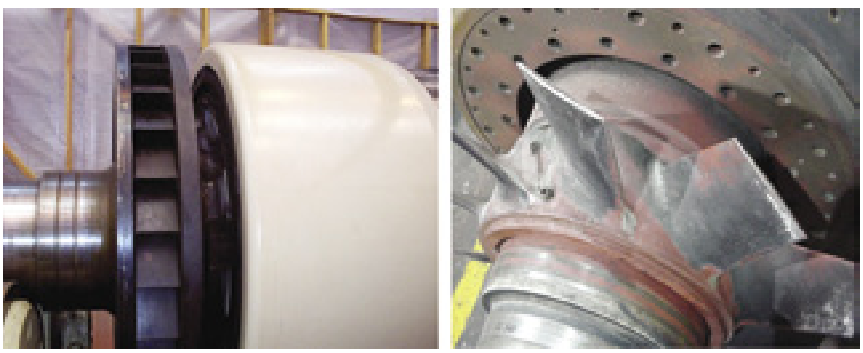
The foregoing, of course, is not new to senior personnel at the nation's generating stations, which is why CTOTF's Leadership Committee has committed to supporting a one-day roundtable dedicated to generators, HV electrical gear, and I&C at its semiannual meetings. This is significantly more "air" time than generators get at most user group meetings in this sector of the industry. This portion of the CTOTF program is chaired by Moh Saleh of Salt River Project; vice chair are NAES Corp's Craig Courter and Braintree Electric Light Dept's John-Erik Nelson.

CCJ has followed CTOTF's lead by expanding its coverage of generators, primarily in association with Consultant Clyde Maughan, who has contributed several articles on their inspection, troubleshooting, and maintenance over the last couple of years. Use the search function on the home page of www.ccj-online.com to access Maughan's work.

More information on generator design, operation, and maintenance of value to plant personnel can be accessed through CTOTF's Presentations Library. Plus, an extensive collection of technical papers on generators—including six decades worth of Maughan's writings—is available at www.GeneratorTechnicalForum.org, the home of the all-volunteer International Generator Technical Community. Both of these websites also support online forums to help you get answers to questions.

Generator auxiliaries. The overwhelming majority of generator presentations at user group meetings focuses on field (rotor) and stator windings—inspection, testing, maintenance, replacement, upgrade, etc. While they may be the most important parts of the generator—especially in the minds of the OEMs and third-party services providers who provide replacement coils—Saleh and his vice chairs know from experience that the failure of a key auxiliary can take you out of service just as quickly.

W Howard Moudy, director of service management for National Electric Coil, lead a discussion last fall on gen-



11. Generator rotor fans, squirrel cage left and axial right, circulating cooling gas to keep windings at desired temperature erator auxiliaries both to acknowledge the importance of these components and suggest ways to mitigate the risk of their contributing to the extension of a planned outage, or causing a forced outage. Moody, highly visible at user-group meetings, dedicates a considerable amount of time to helping owner/operators assure top performance from their generators through application of best practices and lessons learned.

The generator expert began with an overview of cooling systems that highlighted areas of concern with each. The most common form of cooling, Moody said, was air, with the leading technology alternatives being OAC (open air cooled) and TEWAC (totally enclosed water-to-air cooled).

The biggest challenge for these units, he continued, is cleanliness, stressing the importance of quality, long-lived, low-pressure-drop filters to maximize the time between generator cleanings and help maintain optimum output. Recommendations: Prefilters to protect final filters, the latter having Ashrae MERV ratings from 13 to 16.

Hydrogen-cooled generators have several important components that benefit from close monitoring. These include rotor fans to circulate the gas, coolers to maintain the optimal winding temperature, and dryer skids for maintaining hydrogen purity. It's important to keep hydrogen clean and dry.

Keep in mind that entrained oil contributes to loose coils, which are conducive to abrasion to ground insulation. Water-cooled generators require demineralized water to circulate through hollow conductors in stator bars. Pumps, filters, valves, meters, and special fittings are auxiliaries of interest.

Moody spent about 10 minutes on excitation systems, including their testing, before moving on to rotor fans, which may be of the squirrel-cage or axial type (Fig 11). He mentioned to attendees that generators designed by GE have two fans—one at either end of the generator rotor. By contrast, those of Westinghouse (now Siemens) design have one fan mounted on the turbine end. Moody warned against attaching balance weights to rotor fan blades.

Tips on preventing/correcting bushing issues—such as overheating, deterioration of gasket/sealing material, and cracked porcelain—came next, followed by discussion of collector rings, brush holders, and brushes. Recall that the collector ring is the rotating member, shrunk-fit on the rotor shaft over an insulated sleeve, which collects excitation direct current from carbon brushes and brings it to the field winding via special connections. The collector-ring surface usually is grooved to even out brush wear and reduce sparking.

Collector rings vary in size and number—depending on how much current must be supplied to the field. Rings wear over time, often unevenly, and require periodic truing. Carbon dust is a byproduct of the wear and tear and it can accumulate and harden in brush boxes, preventing the free movement of brushes. This condition, as well as weak springs, can compromise brush-to-ring connections and cause arcing. Ring fires may result.

Moudy concluded with his thoughts on journals and bearings. He showed some ugly photos of journal damage, which usually is caused by lube-oil contamination or starvation (Fig 12). Serious damage can occur, resulting in major repairs to the rotor forging. Very serious damage may require cutting off the affected area and the welding on of a new stub shaft. Minor damage occurs over time because of impurities in the lube oil and it typically requires just honing and/or polishing to correct.

12. Journal damage often is caused by lube-oil contamination or starvation

Ring fire

The morning after NEC's Moudy spoke to attendees about the risks associated with ignoring OEM-suggested maintenance of exciter collector rings and brush systems, Cutsforth Inc's Senior Application Specialist Steve Thompson called the editors to report a damaging ring fire that required immediate attention.

Plant personnel told Thompson the fire was so intense that material literally blew out of the housing, as evidenced by the holes shown in Figs 13 and 14. Cutsforth normally is able to repair/refurbish/upgrade brush rigging onsite, but the severity of the damage here was such that the entire housing required a shop visit for a complete rebuild.

Thompson said Cutsforth is seeing an increasing amount of work from the 7F fleet. One reason, he believes, is because low gas prices have owners running units base-load that had been in daily-start and peaking service. Here's what Thompson sees as the root causes of the recent damage:

- Brushes never have to be changed online when turbine/generators are in daily-start or peaking service. Apparently, some deck-plates personnel were not trained in online inspection and replacement of brushes before the shift to base-load operation and this critical work was not being done, thereby allowing the opportunity for exciter brush systems to spark and arc their way to destruction.
- Weak brush springs are a big issue, Thompson continued. Many have not been changed—ever. Most units in the 7F fleet were installed during the bubble and typically are from eight to 12 years old. Springs lose their "spring" whether you run or not. Combine carbon deposits from increased run time and weak springs and you have the perfect recipe for selective action, which is conducive to overheating and fires.
- Mixing of brushes is contributing to or directly causing some ring fires. Having a matched set of brushes is important: Do not mix brushes manufactured to different specifications. Proper brush composition and dimensions, and lead current-carrying capacity, are critical to success. Allowing purchasing agents to ignore your directions and buy from irresponsible offshore suppliers creates safety issues.

Moudy

GE legacy engines

Meeting after CTOTF meeting, every seat is occupied at the roundtable dedicated to GE E- and legacy-class engines. There are two obvious reasons for this: First, there's a slew of Frame 5, 6B, and 7B-EA engines in electric generation service in the Western Hemisphere; second, in an era where real content and critical discussion are king, this session never disappoints.

Less obvious is that the session chair—Pierre Boehler of GenON Energy—and vice chair—Ed Wong of NRG Energy—are among the industry's O&M technology elite with long experience. Boehler, in fact, was a founding member of the 7F Users Group more than 20 years ago.

At the fall meeting, Boehler's and Wong's session featured the following in-depth technical presentations:

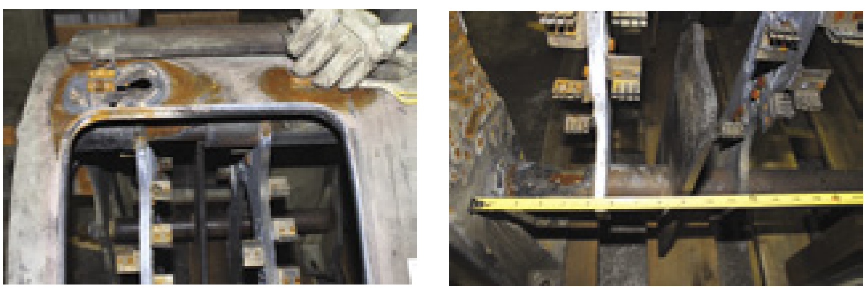
- Profile of a major inspection by a user.
- "How to Inspect, Repair, or Replace GT Inlet and Exhaust System Components," by David Clarida, Integrity Power Solutions LLC.
- "Frame 6 Gear Drive O&M Considerations," George D Lankford, Philadelphia Gear Corp, a Timken company.
- "Gas Turbine End of Life," Paul Tucker, First Independent Rotor Service of Texas (FIRST).

Outage profile

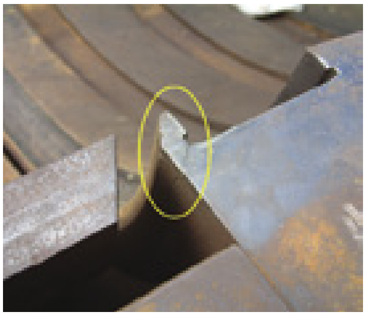
A user focused on highlights of a major inspection for a Frame 7 unit which was particularly valuable for the open discussion it created. Best practices, lessons learned, and issues requiring solutions also were included in the presentation, based on experience with the unit that underwent the major, plus several others in the owner's fleet.

Tucker

First best practice: Inspection checklist for inlet air houses and associated ductwork for cold-climate readiness. It was developed for the owner's Gulf Coast plants, three of which had suffered compressor damage from ice the previous year during a prolonged cold snap. A primary objective was to inspect Frame 7 E-class units for potential water-ingress sources to mitigate potential FOD from ice formation. The following are key elements of the program:



13, 14. Ring fire was so intense that material blew out of the housing, as evidenced by the holes clearly visible in the photo at the left



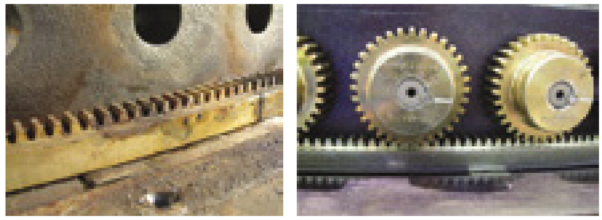
15. Row 4 vane-carrier slot was found cracked at the fifth-stage air extraction

16. Forward compressor case was removed and shipped to a repair shop (right)

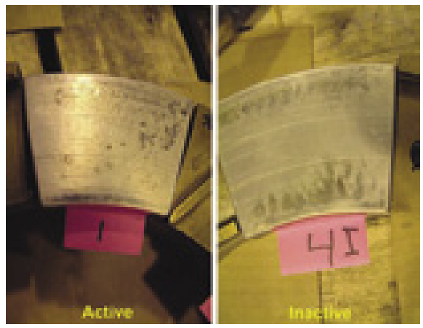
17. A patch ring was machined and installed in the shop. Photo shows fit-up is assured

18. Patch ring and vane carrier are installed, ready for service

19. Considerable pitting was found on inlet guide vanes



20, 21. IGV rack gear, found corroded (left), was replaced (right)



22. Active thrust-bearing pad (left) revealed some wear and tear; inactive pad is at right

- Check the inlet screen and swing gate for integrity and operability; repair as needed. Access is by rolling scaffold or forklift with basket.
- Inspect inlet house and associated ductwork (access via scaffold or forklift through the swing screen) for potential water ingress using a light source. Check silencers and trash and bird screens for damage. Spray water over the inlet house and ductwork from an aerial lift and inspect internally for water ingress. Make repairs as necessary.
- Conduct a similar inspection (as described in the second bullet point) of the bellmouth inlet duct/elbow area.
- Make a final walk through of the areas accessed to be sure people, tools/equipment, and repair materials have been removed and the units is fit to return to service.

Second best practice. The presenter's description of repairs made to the Row 4 vane-carrier slot rail, which had cracked at the fifth-stage air extraction (Fig 15), was of considerable interest, judging from the body language of attendees. The forward compressor case was removed (Fig 16) and a patch ring was machined and installed in the vendor's shop (Figs 17 and 18). This 30-in. circumferential case crack resembled ones often experienced on Frame 5s, but those are found further back in the compressor.

Other best practices included the plant's positive experience with non-OEM combustion hardware and with the use of remote video inspection tools to assess generator condition. Use of Nimonic forged cast aft mounts on transition pieces have had a positive impact by shifting dynamics to higher frequencies. Condition of the mounts was rated "good" during an inspection after nearly 800 starts. Inspection of low-residence-time fuel nozzles revealed similarly good results—no issues after more than 600 starts.

Lessons learned can be painful. A significant portion of the presentation addressed compressor stator vane and shim migration issues for Stages 1-8. Recall that the first four stages each have six vane carriers into which the airfoils are inserted; Stages 5-8 have individual vanes. A non-OEM supplier was selected to provide replacement stator hardware for the first eight rows. Existing vanes were retained in the downstream stages, where shim migration was addressed by pinning.

There were fit-up issues with the new vanes for Stages 5-8. The individual vanes wouldn't slide into the case on the first attempt and their bases had to be beveled. Vane bases also were found undersize and shims were required to set the horizontal-joint gap and pinned to the vanes. Finally, vane tip heights were too short. The vane carriers for the first four compressor stages were provided slightly longer than required and field-machined to fit exactly without the need for shims.

Several more issues had to be resolved during the outage to assure reliable service going forward. Among them:

- Pitting of inlet guide vanes was identified and addressed (Fig 19).
- Corroded rack gear was removed (Fig 20) and new pinions and rack were installed (Fig 21).
- Bearings revealed some wear and tear. Compare typical as-found active and inactive thrust pads in Fig 22.
- Significant wear and tear was found on both first- and second-stage shroud blocks (Fig 23).
- Turbine case cracks are a recurring problem and are repaired every outage.
- Exhaust-case cladding damage is an ongoing battle as well.

Inlet, exhaust systems

David Clarida is well known to CCJ subscribers for his insightful article on gas-turbine exhaust systems in the 2010 Outage Handbook. It covered

23. First-stage shroud blocks had seen better days

virtually all of what Clarida had to say at CTOTF on exhaust systems. Not covered, however, were his comments on inlet-system inspections.

The most common inlet-system concerns of owner/operators, Clarida said, are the following:

- Safety—inlet acoustics.
- Operations—engine compressor FOD (foreign object damage) and deposits.
- Maintenance—inlet corrosion.
- Performance—equipment failure, high pressure drop.

Clarida

To address these potential issues, Clarida suggested checking the inlet system thoroughly before each outage. His key points were:

- Develop an inlet acoustic-performance baseline.
- Listen for internal noise so you don't miss a possible failure in the internal insulation system.
- Inspect expansion joints for breaches that allow unfiltered ambient air to enter the compressor.
- Inspect for other avenues for air bypass, including shell-plate corrosion, improper sealing of filter elements, etc. It's easy to find holidays in the shell of the inlet air house and associated ductwork by standing inside the darkened structure on a bright sunny day (with the engine off, of course) and looking for rays of sunlight.
- Evaluate the inlet system to see if it's compatible with the actual operating environment. Oftentimes little real engineering is done on inlet systems during the plant design phase and the "standard" components installed may not be meeting expectations.

During the outage, he recommended checking the following:

- Integrity of internal insulation and liners.
- Internal corrosion.
- The entire filter house for proper installation of filter media and evap-cooler media or fogging nozzles, if installed.
- Integrity of the inlet trash screen.

Load, accessory gears

Philadelphia Gear's Lankford is the type of speaker users want to listen to—knowledgeable, with an easy presentation style. He has lived gears virtually every day since joining the company in 1978 as a design engineer and has had years of deck-plates responsibility for the overhaul, installation, and alignment of load and accessory gears for gas turbines. Plus, he is a Level II certified vibration analyst. Lankford "knew" the people he was addressing and what their information needs were.

While the speaker's assignment was to focus on O&M considerations for Frame 6 gears, gears are gears and his presentation was of high value to most attendees who did not have 6Bs in their equipment stables. Lankford began by listing several "must-dos" to guide your maintenance program and avoid gear problems to the extent possible. Here's what he suggested:

- Look at trend data, not single data points.
- Be consistent during data acquisition.
- Automate recordkeeping to allow rapid evaluation of data.
- Know your equipment baselines, taken at startup and after repair.
- Identify and maintain access to critical spares.
- Buy OEM quality replacement parts.

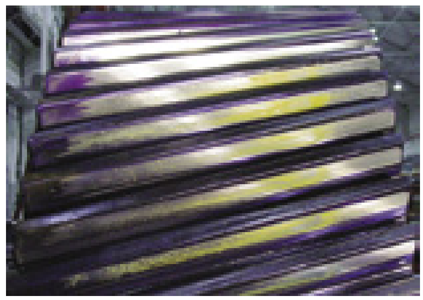
Next, he identified the following as criteria for repair based on the results of inspections and monitoring activities:

- Visual inspection. Significant shift tooth contact pattern, rapid change in the level of tooth wear, and significant levels of metallic debris.
- Vibration. Significant increase in vibration amplitude at the equipment's predominant frequencies in any plane.
- Oil sample/wear particle analysis. Significant increase in high-alloy steel particles (from gears) and/or in bronze, tin, or lead particles (from bearings).
- Noise and temperature. Significant change in noise level or the identification of unusual noise; significant increase in oil temperature.

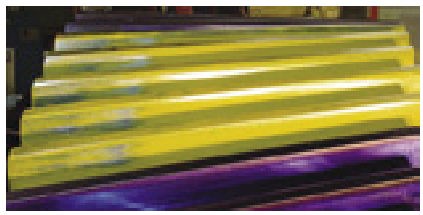
Lankford reviewed vibration basics, such as a signature that is 1 × shaft rpm points to a single gear tooth defect or rotor unbalance; 2 × shaft rpm indicates axial misalignment. He urged attendees to avoid the temptation of becoming an amateur vibration expert. Leave vibration analysis to those trained in the science, he said.

Data are easily misinterpreted and only the trained eye will likely spot such things as an improper transducer, poor choice of data points, etc. The experienced analyst has the background to determine if the reading obtained is reasonable and if other symptoms agree with the finding.

Proper tooth contact and how and when to check for it got its share of air time as did ways for correcting misalignment, if found. Apply hard blue during each outage was the suggestion made to users for identifying uneven wear; look for changes over time by comparing current photos with those from past years. Optimal condition is a centered wear pattern tapering off at each end (Fig 24). Unacceptable tooth contact is illustrated in Fig 25.



24. Optimum contact pattern is centered, tapering off at each end not necessarily full contact



25. Unacceptable tooth contact

Lankford paused to explain more about bluing. Use soft blue, he said, when the accessory gearbox is disconnected from the turbine during an outage and the gears can be turned by hand to see the contact area. Use hard blue when the gears are coupled to load.

The causes of poor contact include these:

- Excessive bearing clearance or damage
- Housing bore damage or misalignment.
- Uneven foundation or improper

support (soft foot).

- Gear geometry mismatch.
- Shaft, casing, or tooth deflection under load.
- Thermal distortion under load.
- Component-to-component misalignment.

Correction of poor contact may require resetting or replacing bearings, remachining the casing, reshimming the casing/fixing the foundation, and/or compensating for deflection and thermal distortion with modified geometry (lead modification).

Lankford stressed that a properly maintained and operated gearbox should operate trouble-free without an overhaul for its design service life of 20 years or more. Only when issues are identified by an adequate condition monitoring/preventive maintenance program should the decision to teardown, inspect, and overhaul a gearbox be made.

The gear expert said, "When you take apart a perfectly serviceable gearbox, the probability of doing more harm than good is greater than any of us care to imagine." Contamination ingress, improper fit-up of parts, the risk of breaking hard-to-access components (such as thermocouple wires), etc, militate against teardown unless absolutely necessary.

Rotor end-of-life inspections

OEMs tell users their gas turbines have critical parts with finite lifetimes and that replacement of these parts may be necessary to assure reliability and safety moving forward. Rotors are a primary target of this initiative. Today, the only way to determine if an ageing rotor is in sufficiently good condition to continue operating is to disassemble it and to nondestructively examine individual wheels, bolts, etc.

Tucker's company, FIRST, is one of relatively few third-party service providers experienced in end-of-life (EOL) rotor inspections on Frame 5s and 7B-EAs. Some of the firm's early work was presented at CTOTF's fall meeting in 2007. The subject of that report was a 7C rotor from a 1 × 1 STAG 100 combined cycle installed at Arizona Public Service Co's West Phoenix Generating that had more than 6000 actual starts at the time of the inspection; it is still operating today.

The rigorous inspection program conducted revealed no reportable indications. This led the inspection team to conclude, based on inspection-process fidelity, inspection methodology/criteria experience, and the excellent inspection report, that it was "more than reasonable to assume no defects would grow and propagate into anything near critical flaw size in the next major inspection interval."

Inspections conducted by FIRST to determine if an engine is fit for duty include the following:

- 100% three-dimensional boresonic inspection for internal flaws.
- Eddy-current inspection for creep.
- Hardness and replication for grain structure.
- Critical diameters measured for bore shrinkage.
- Finite element analysis (FEA) when flaws are identified.

Regarding the last point, FIRST and its business associates have developed rotor-component fracture models to perform FEA analyses when needed. Tucker said that FIRST's critical-flaw-size and fatigue-life estimations enable the company to analyze flaws with its models to see if flaw characteristics are detrimental to machine operation. He said the models can determine if specific flaws will fail, and if so, when in terms of hours and/or starts.

For Frame 5P EOL inspections currently being conducted in FIRST's Houston shop, Tucker is checking compressor wheels for rows 13 to 16, the distance piece, and both the HP and LP turbine disks. In one of the machines, a flaw cluster in the HP turbine wheel was identified during the phased-array ultrasonic inspection. FEA analysis suggested that this wheel not be returned to service.

More recently, FIRST found a flaw in the 16th-stage compressor wheel of a Frame 5 rotor with 4800 starts. FEA analysis showed it to be "non-detrimental." Tucker pointed out that the material used for compressor wheels is more forgiving than that used in the manufacture of turbine disks. He stressed, "What you might find is not always bad," mentioning that some users he speaks to believe a material defect means the part must be scrapped. Not true, Tucker continued, it's not a "gloom-and-doom" thing.

Inspections conducted by FIRST nominally take five days; however, analysis of any flaw that might be found can add a couple of weeks or more to the schedule. Tucker suggested to the owner/operators that they do an EOL inspection earlier rather than later—during a major or when they are going to replace compressor blades.

Having a baseline condition assessment enables users to better manage the lives of their rotors, he said. Plus, if it appears that one or more components will have to be replaced in the future, knowing earlier allows owner/operators to plan for that eventuality and to order refurbished or new parts on a standard delivery schedule. CCJ

Flow-accelerated Corrosion (FAC)

in Fossil and Combined Cycle/HRSG Plants 2013 International Conference

Call for Papers and Initial Information Tuesday, March 26, 2013 - Thursday, March 29, 2013

Associated Organizations

CEATI International/Centre for Energy Advancement through Technological Innovation
Combined Cycle Journal
Electric Power Research Institute (EPRI)
International Association for the Properties of Water and Steam (IAPWS)
PowerPlant Chemistry Journal
Structural Integrity Associates, Inc.

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801 North Glebe Road
Arlington, VA 22203
USA

The 2013 International Conference marks the second gathering of technical experts and end users to focus on all aspects of FAC in fossil and combined cycle systems. The inaugural conference held in 2010 was attended by 170 people from 21 countries and featured a technical program with 40 papers. The conference will be linked to the 2013 FAC Conference, May 21-24, 2013, organized by Électricité de France, which focuses on FAC in the nuclear power industry.

The 2013 International Conference on Flow-accelerated Corrosion (FAC) in Fossil and Combined Cycle/HRSG Plants will be held on March 26-28, 2013. Total attendance is targeted at 180 people. The conference will include an Exhibition Area and is seeking exhibitors and sponsors to support various conference activities. An Expert Panel and Roundtable Discussion is planned for the morning of March 29.

Who should attend the conference?

Anyone involved with FAC, including researchers, industry personnel (including engineers, chemists, operators and managers), and technical product and services organizations will benefit from attendance.

Summary Agenda

Day 1: Tuesday, March 26
07:00 Registration/Exhibition Open
08:00 to 17:00 Conference Sessions
17:30 to 19:30 Social and Networking Gathering

Day 2: Wednesday, March 27
08:00 to 17:00 Conference Sessions
17:30 to 20:00 Conference Reception and Buffet in Exhibition Area

Day 3: Thursday, March 28
08:00 to 17:00 Conference Sessions
17:00 Conference Adjourned / Exhibition Closed

Day 4: Friday, March 29
08:00 to 12:00 FAC Experts Panel and Roundtable Discussion

Call for Conference Papers

The conference will consist of both invited and contributed technical papers. Abstracts must be submitted by September 30, 2012, to guarantee consideration by the conference chairmen. Authors will be notified of acceptance by October 31, 2012. Authors of accepted papers should be prepared to submit the completed paper and/or presentation materials by February 15th, 2013.

Person to receive abstracts: Barry Dooley via bdooley@structint.com

Subjects to be covered during the conference include:

- FAC in Fossil Plants
- Conventional Fossil Power Plants
- Combined Cycle Plants with Heat Recovery Steam Generators
- FAC in Other Industries (Refineries, Pulp and Paper, Dairies and Food Supply Systems, Industrial Steam Plants, City Steam and Water Supply Systems, Geothermal, etc.)
- Cycle Chemistry Influences on FAC
- Materials Aspects of FAC
- FAC Research Activities
- FAC Damage Mechanisms
- FAC Modeling
- Programs for Management of FAC
- Predictive Methods
- Inspection and NDE Technologies
- Repair and Replacement
- Life Management
- End User Experiences

Conference International Advisory Group Members

- David Addison, Thermal Chemistry, New Zealand
- Bob Anderson, Competitive Power Resources, USA
- Dr. Geoff Bignold, GJB Consulting, UK
- Professor Albert Bursik, PowerPlant Chemistry, Germany
- Darryl Glanton, EPRI, USA
- Tom Gilchrist, Tri-State G&T, USA
- Andy Howell, Xcel Energy, USA
- Gary Joy, CS Energy, Australia
- Dr. Zhigang Li, TPRI, China
- Professor Derek Lister, University New Brunswick, Canada
- Des McInnes, Stanwell, Australia
- Keith Northcott, Eskom, South Africa
- Professor Tamara Petrova, Moscow Power Institute, Russia
- Michael Rziha, Siemens, Germany
- Professor Hiroshi Takaku, Shinshu University, Japan
- Stephane Trevin, Électricité de France (EDF), France
- Professor Shunshuke Uchida, JAERI, Japan
- Stan Walker, EPRI, USA
- Daniel Zinemanas, Israel Electric, Israel

For information as it becomes available, and to register, visit www.facfossilhrsgconference.com

Minimize the risk of catastrophic failure from contaminated inlet air

John Molloy, PE, M&M Engineering Associates Inc

A typical F-class compressor ingests nearly 1000 lb/sec of air containing a spectrum of minerals, salts, and volatile organic compounds present in the ambient atmosphere. Locally high concentrations of corrosive compounds also may exist because of surrounding industries—or even from the powerplant itself, such as cooling-tower drift or water treatment effluent.

Gas-turbine owner/operators are well aware that airborne contaminants foul compressor blades and vanes, reducing efficiency. But they may not know that contaminants also can serve as nucleation sites for under-deposit corrosion cells, which can have dramatic implications for component life, including increased risk of catastrophic failure (Fig 1).

Online and offline compressor water washing with detergents has been used with some success by GT operators to mitigate the effects of deposit accumulation. However, tenacious deposits invariably accumulate over time. Activation of these deposits, by the presence of moisture, is conducive to the formation of corrosion cells that can quickly corrode the types of stainless steels typically used in making airfoils.

High-strength precipitation-hardening (PH) stainless-steel blades and vanes suffer a particularly high loss in fatigue threshold properties from pitting. They are more prone than some alternative materials to suffer airfoil liberation caused by cracking nucleated at pitting.

Observations by M&M Engineering engineers and metallurgists include a combination of leading-edge erosion and pitting in the first few compressor stages of some machines. While erosion is most often the result of online water washing, it also can be caused by ineffective filtration of inlet air attributed to poor filter selection, poor condition of filter media, and/or bypassing of filter elements. Important to note is that an eroded leading edge is an ideal location for compressor deposits to become deeply embedded.

Given the drop in compressor efficiency, the irreversible damage caused by erosion and corrosion pitting (Figs 2 and 3), and the risk of catastrophic damage from fracture initiation at corrosion pits, it is in your best interest to have a mitigation strategy for compressor deposit accumulation. Moreover, the strategy selected should consider a scenario where some accumulation is unavoidable and how to reduce the activation of these deposits.

Finally, particular attention should be paid to units with a history of blade failures attributed to a design limitation that makes them more susceptible to corrosion fatigue cracking. Such units would have a very low tolerance to the presence of corrosion pitting.

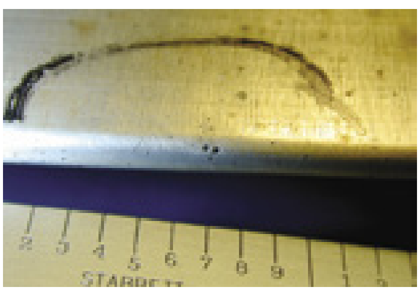
1. Compressor blades from a 501D5 reveal a fractured tip and heavy deposits

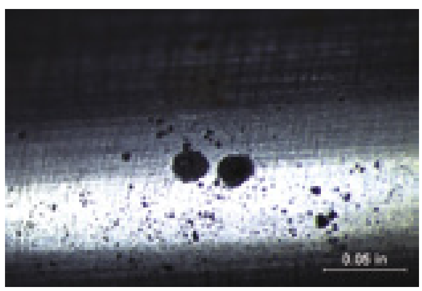
Sources of contamination

Soil. Depending on local geological conditions, any given soil can contain large amounts of calcium, iron, magnesium, aluminum, potassium, sodium, phosphorus, and sulfur. There are other less-common species as well—including chlorides, where dry land used to be a sea bed. These elements always are present in compound form, such as an oxide or salt.

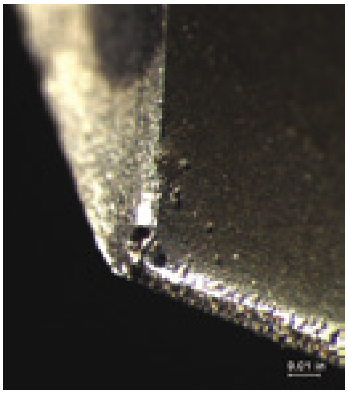
Even with reasonably high-efficiency filtration capable of removing 99.7% of the particulates within a given particle size range, the remaining 0.3% contamination multiplied by 1000 lb/sec of influent air is conducive to a high rate of deposit accumulation.

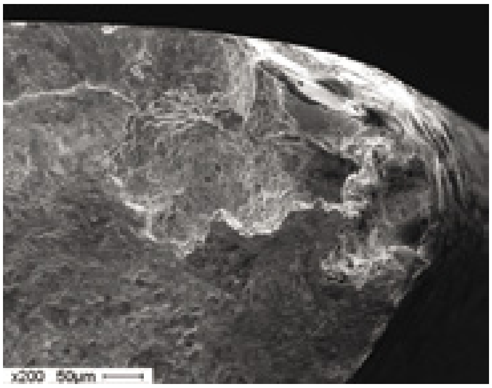
Chlorides in salts will rapidly corrode (pit) all of the stainless steels used in GT compressors (Figs 4 and 5). The only class of materials reasonably immune to chloride or under-deposit corrosion is the titanium alloy blades and vanes used in flight turbines and



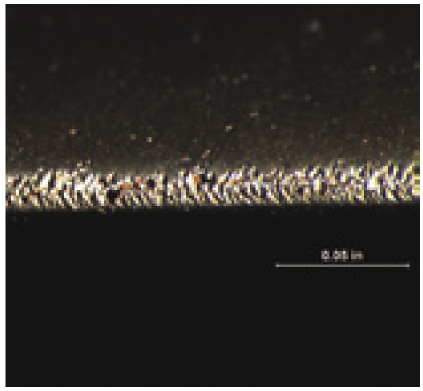


2, 3. Pitting is in evidence on the leading edge of a 7FA compressor blade. Close-up view is at right





4, 5. Leading-edge pitting caused by airborne chlorides is adjacent to fracture surface on 7FA vane. Close-up view of the damage is at right



6. Leading-edge erosion provides nucleation sites for additional pitting

possibly some land-based aeroderivative units. Sulfur-containing compounds are commonly found on compressor airfoils, but also have been identified in larger quantities in cracks on Inconel 706 turbine wheels used on F-class units.

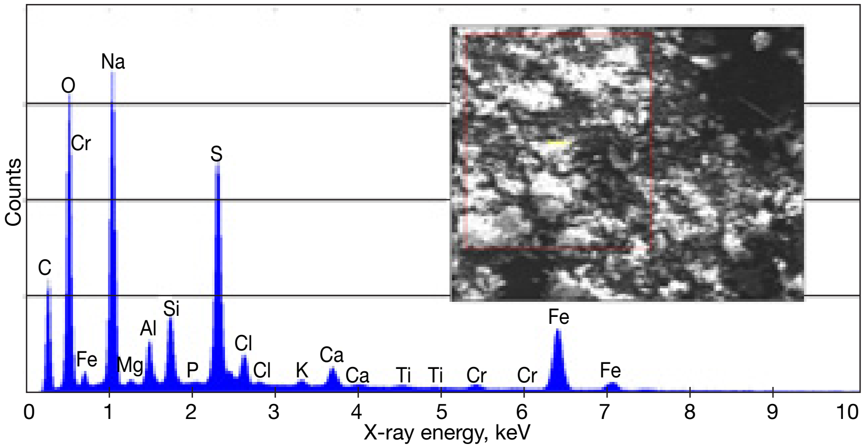
Air. The quality of air entering the compressor is highly variable, but nevertheless dependent on geographic location. Coastal regions present an obvious problem with their humid, chlorides-laden atmosphere. Units in such areas are especially vulnerable to pitting. Special inlet ducting and tailored filtration may provide some level of protection.

Plants with wet cooling towers may present similar problems—particularly when GT inlets are located downwind of towers. Also, use of sodium hypochlorite for microbial control of tower water can allow chlorine-laden air to enter the compressor. The solution here may be as simple as using a non-chloride-based biocide of microbial control. In some cases, the corrodents can come from atypical activities at the plant—such as excursions of acid vapors from water treatment facilities (sulfuric or hydrochloric acid).

Close proximity to local industry—such as steel mills, coal- or lignite-fired boilers, or refineries—can result in a large influent concentrations of sulfur-bearing compounds, which when incorporated into a deposit layer, can accelerate under-deposit corrosion and pitting.

Water. The water source used for online and offline water washing, as well as the water used for power augmentation, should be of demineralized quality or better. The use of city water or another source of hard water is discouraged. Online water washing with a hard water source will increase deposit accumulation at and beyond the phase transition area, where the water boils to vapor and deposits the minerals in solution.

Power augmentation by closed-loop chiller system also affords the opportunity for contamination should leaks develop in the chilled-fluid circuit. These fluids can have variable water quality as well as chemicals added to the chiller loop. Non-volatile constituents of the chilled water would leave deposits similar to those from hard water. As mentioned earlier, online water washing can cause leading-edge erosion if the droplet size is not controlled, or if leaking occurs during operation (Fig 6).



7. EDS spectrum analyzes typical compressor deposit. Sodium, sulfur, and chlorine indicate the presence of potentially corrosive compounds

Observed contaminants

M&M Engineering has for many years sampled the deposits removed from GT compressor airfoils in many geographic regions of the world. A pattern of contaminants (the usual suspects) has been observed, with some exceptions. The deposits observed are biased largely by one of the dominant contributors—that is, coastal conditions, soil condition, or local environment.

Energy dispersive spectroscopy (EDS) provides qualitative elemental analysis of materials under scanning electron microscope (SEM) examination based on the characteristic energies of x-rays produced by the electron beam striking the sample (Fig 7). The relative concentrations of the identified elements are determined using semi-quantitative, standardless quantification (SQ) software.

Pitting

Pitting of compressor blades and vanes always is caused by under-deposit corrosion aggravated by the presence of corrosive species in the deposit. The corrosive species most often are sulfur- and chlorine-containing compounds, but pitting also can occur simply from the presence of oxygen under the deposit. Pitting is proof of corrosive deposits; trace amounts of corrosive species identified by EDS at the bottom of the pits identifies the active corrodents. Such examination allows fine tuning of treatment for that species (Sidebar).

Recall that the source of the corrodents can be local to the plant, in the soil, from the atmosphere, or from local industry. In some cases, the corrodents can come from atypical activities at the plant—such as the use of sodium hypochlorite (bleach) for biological control, or excursions of acid vapors from the water treatment facilities. Plant

Limitations of erosion, pitting assessments

Most OEMs and some independent service providers perform replications of leading-edge erosion and pitting. Users should be aware that given the typical undercut pitting morphology observed on most blade pits, a large portion of the pit will not be captured in a replication.

This method of examination and evaluation accurately reflects broad surface pitting, but not undercut pits. Reason: Impression media typically does not flow into undercut pits. Even if it did, it likely would break off and remain in the pit when the impression media is peeled from the blade airfoil surface.

Moreover, pits often are packed full with compressor deposits and corrosion byproducts, again resulting in vastly underestimated pit depth. Finally, an indication replicated by a mold will not be able to differentiate between pits caused by corrosion (deep and undercut) and those from foreign object damage (small particles that leave divots on the leading edge of the blade). This requires a trained eye during a visual inspection. The result of the foregoing is that the depth of attack will be underestimated.

A better method is simply magnified photographic documentation where the "black dots" on the blades are confirmed to be pits. A safe assumption is that the pit is at least as deep as it is wide.

operations can identify, address, and mitigate the local sources.

Regarding low-fired-hours units, life-limiting pitting is difficult to understand without considering the effect of offline corrosion. For cycling units, a substantial amount of time is spent waiting for the call to start (refer to 7EA experience, p 76). During idle periods, the unit typically is on turning gear a large portion of the time and there may not be provision for supplying dry air. This is when corrosive deposits combine with moisture to create conditions ideal for pitting—particularly if the deposits contain a substantial concentration of sulfur- and chlorine-containing compounds.

Mitigation strategies

Units may be water washed online without detergent each day they are operated when ambient temperature is higher than about 50F. Offline washing with detergent usually is performed prior to performance testing or to restore lost capacity. Compressors typically are washed offline from one to four times a year depending on air quality and other factors. Both methods of washing provide performance benefits and help prevent the accumulation of corrosive deposits (also known as crud).

However, performing an online wash prior to operation does not remove the deposits that would be accumulated during the subsequent operating cycle, nor does it remove much crud beyond the first several stages of the compressor because of the phase transition from liquid to vapor.

Moreover, if the subsequent operation cycle is followed by a long idle period in cool, humid weather, the deposits can absorb the ambient moisture and activate the corrodents. Ideally, the online wash should be performed near the end of the cycle, but with sufficient time to ensure proper drying of the compressor and residual, tenacious deposits.

Offline washes should be done with demineralized water and a cleaning solution tailored to the deposits. Proper rinses with conductivity measurements taken at the drain ports are advised. Offline washing is much more effective at removing accumulated deposits, but proper drying is necessary to prevent pitting under any remaining crud.

An aspect of GT O&M critical to minimizing deposits and moisture infiltration is proper sealing of the inlet filter house. All seams should be sealed with a weatherproof material and the fitment surfaces should be in good condition. Water leaks from the roof or any other area that causes standing water should be addressed.

Susceptibility to deposit accumulation can be minimized by use of high-efficiency filtration media and aggressive offline washing with a proper cleaning solution. To minimize the presence of water, washing should be followed by operation until all moisture is evaporated. Use of appropriate weather protection and mist eliminators on the air inlet house, as well as filter elements capable of removing moisture, also are suggested.

Finally, layup periods should be combined with closure of the bellmouth area and with a source of dry air (heater or dehumidifier) to ensure corrosive deposits are not activated. Stack dampers are beneficial as well, reducing the ingress of moisture into the gas turbine. CCJ

Ensure a reliable, sufficient supply of quality water to support generation assets

By David Addison and **Judy Weir,** Thermal Chemistry Ltd

The purpose of any water treatment plant (WTP) for this industry is to produce a reliable and sufficient supply of product at the quality required by the host plant to support generation operations. Organizations such as EPRI and the International Association for the Properties of Water and Steam have long advocated the need to maintain strict quality limits for both makeup and the steam/water cycle to avoid issues such as boiler tube failures and steam-turbine deposition and corrosion.

Power generators call their WTPs by different names, some of which refer only to a specific part of the total system—such as deionization or pretreatment. For this presentation, the term WTP refers to all treatment processes used in the production of demineralized makeup from the raw water supplied to the plant.

Pretreatment refers to that segment of the WTP producing clarified and/or filtered water for downstream demineralization. It can range from simple chlorination and physical filtration of the water supply to chemical clarification and flocculation followed by sand or multimedia filtration.

The demineralization plant refers to the system that removes dissolved ions and produces water of very low conductivity (less than 10 μS/m) and silica (less than 10 μg/L) for boiler makeup, gas-turbine NO_x control, etc. The technology may be membrane-based—like reverse osmosis (RO) followed by continuous electrodeionization (CEDI)—or ion exchange, using resin beds.

Quality, quantity, and reliability are interlinked, and often the issues impacting one—such as changes in feedwater quality, plant operation, and/or maintenance—affect all. It is difficult to talk about one of these variables without referring to the others.

Quantity is important because the WTP is designed to produce a certain amount of product consistent with the quality and variability of the incoming water. For example, with ion-exchange demineralization, each resin bed is capable of producing a certain quantity of final product water depending on the amount of resin in the bed, how many free sites this volume of resin has to exchange its hydroxyl and hydrogen ions, and the concentration and types of ions present in the feed water.

A change in the quality of incoming water—such as a higher concentration of total dissolved solids (TDS), increase in fouling potential, and/or regeneration problems are common reasons why a given resin bed does not achieve the desired amount of product water between regenerations.

A similar change in the quality of water flowing through RO and CEDI units also causes a decrease in product quality if the plant is left unmonitored. However, if output is reduced within design limits then the desired quality sometimes can still be maintained.

Unless there is a significant amount of redundancy built into a WTP—uncommon in today's "cost-optimized" projects—and any of the subsystems fail to produce their design output at the required water quality, demin water quality and/or quantity always is affected. Sometimes a new WTP is installed at significant expense to produce more water when a review and optimization of existing plant design and operations is all that's necessary.

The quality of demineralized water produced is important because the dissolved ions in this water ultimately will enter the heat-recovery steam generator (HRSG) and the steam path. Out-of-spec operation of the demineralizer is conducive to deposition and corrosion in both the boiler and steam turbine.

Sometimes, must-run requirements may "force" demineralizers to remain in service even when they are producing off-spec water. While this action might seem like a good idea at the time, it should not be allowed under any circumstances. The issue merely moves from the WTP to the boiler where it can be very time-consuming and expensive to correct. Also, keep in mind that the further water quality is out of spec, and/or the longer it is out of spec, the faster damage occurs and the worse it is.

Quality parameters are easily measured using the preferred and most-accurate technique of continuous online monitoring, or by grab sampling and manual testing. Problem with the latter is that it could be just that one time during the day when water quality is acceptable. Most probably not, but you just don't know for sure.

Important, too, is that the testing procedure be applicable to the concentration range of the parameter being tested. For example, using a high-level dissolved-silica test method would be suboptimal for testing silica in the low range of 5-20 μg/L.

Also, when testing demin water, it is very important to avoid sample contamination, which can be challenging when grab samples are involved. Just allowing carbon dioxide to dissolve into an open grab sample will elevate its conductivity prior to testing in the laboratory.

Reliability. There is limited value in having a WTP that can produce quality water in the required quantity if it can't do it every time makeup is required. Often, the size of tankage within the WTP, or downstream of the demineralizer, will determine the criticality the plant owner places on system reliability.

For plants with oversize demin tanks, reliability may not be an issue, given that required repairs or maintenance can be completed before the critical water level is reached. An industry standard is for sites to have 24 hours of makeup storage at the normal usage rate.

The main concerns often affecting the availability and reliability of the WTP to produce in-spec makeup 100% of the time it is required are the following:

- The lack of, or even identification of, critical spare parts for a plant that must produce water of a given quality 100% of the time it is needed.
- The lack of priority given to correction of issues. For example, small leaks left weeping or temporarily repaired until they became larger, more critical problems.
- Less-than-satisfactory plant and/or process design, which means water production is limited by, or relies on, a single or unspared component, or has suboptimal equipment and/or materials.
- An inability to understand the reliability status of the plant—such as in the absence of a plant-wide condition monitoring system and/or the amount of chemical monitoring via online or grab-sample analysis is limited.
- Operational practices and managerial decisions that allow out-of-spec water to enter the WTP when the design basis of the plant clearly states it is unable to process, without issue, water of such low quality.

Optimize WTP performance. A performance monitoring program (PMP) is essential for assuring that your water treatment plant is well-operated and –maintained. It is site/plant specific and gathers information on all of your facility's water-treatment processes and equipment. Interestingly, despite their obvious value, such programs are not in use at many sites.

The PMP simplifies fault-finding related to quality and/or quantity shortcomings because critical areas are monitored continually and the data are collected and analyzed. Problems identified should be corrected quickly to maximize WTP availability.

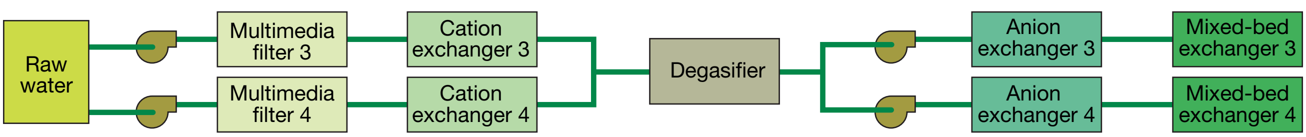
After the initial work involved in implementing a performance monitoring program, and the important parameters are identified and documented, the ongoing operational commitment to monitoring and record-keeping does not require great effort. Large capital outlays or increases in WTP O&M budgets normally are not necessary.

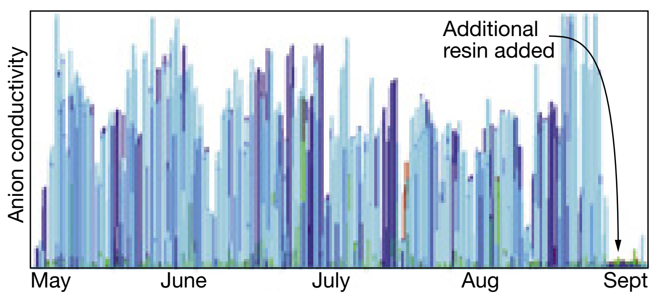
A well-designed program is capable of identifying when potential problems may occur and suggest the most cost-efficient time to replace major cost items like membranes, resin, pumps, and vessels. The program also provides the mechanism for the communication of well-informed and –justified O&M decisions. Specifically, an effective performance monitoring program should include the following:

- A description of the overall water-treatment process and plant.
- A functional description of each component within the WTP.
- Details of persons accountable for the WTP.
- Performance criteria and action limits.
- Monitoring requirements and routine operational practices.
- Maintenance activities.
- Reporting and record-keeping.
- Plant-specific troubleshooting information.
- References to site-controlled procedures.

One dedicated WTP operator or technician per shift should be trained by a chemist on how to conduct minor, but meaningful, tests. Operators also should be trained to have a good technical understanding of the water treatment plant so decisions they make will be informed ones. This will help assure both production of high-quality water and a reliable plant. It is the WTP operator's job to record observations and monitored parameters during walkdowns, take action on observed issues, review plant alarms and data trends, and respond appropriately when action limits are reached.

Calibration and maintenance of all instrumentation is essential if the WTP is to run efficiently. Without this effort, the quality and/or quantity may not be what the owner believes it is. A calibration regime is developed by





A-1. Treatment system added at Site A to accommodate a plant expansion draws surface water from a reservoir. Original system operates on city water

A-2. Anion effluent quality improved from 25-40 to 2-4 µS/cm when resin was added to the cation vessels in September (left) reviewing current practices and producing a schedule. Maintenance checks and routines for mechanical, electrical, and chemical plant components should be documented. As part of this effort, critical spares should be identified and their immediate availability for breakdown repairs ensured.

Finally, the performance monitoring program should be a living document and the information it contains communicated to all relevant site personnel and followed to the letter.

Case history A: Poor product-water quality, reliability

Site A is home to a chemical process plant, constructed in 2004, which originally used all of its demineralized water for producing steam in two coal-fired boilers. The steam plant was a small, but critical part of the much larger process.

Two ion-exchange trains produced the demin water from town-supplied potable water. The facility had no chemist, or anyone else onsite with sufficient knowledge of water chemistry to understand the implications of sending poor-quality water to the boilers.

In 2010, the company initiated a site expansion that included installation of a combined-cycle cogeneration system capable of selling excess power to the grid. The new HRSG operates in parallel with the original coal-fired boilers as well as with a third identical coal-fired boiler added as part of the expansion.

A second water treatment plant (called Stage 2) was added to supply the demin water required for the new boilers. The two-train system shown in Fig A-1 is identical to the original Stage 1 except that its water is supplied from a reservoir rather than from the city system.

As the block diagram shows, raw water first passes through a multimedia filter to reduce turbidity. It then flows through the demin train consisting of a cation vessel, a degasifier serving both trains, an anion vessel, and a mixed-bed exchanger. Stage 2 shares the acid and caustic regeneration system built for Stage 1. Regeneration is of the counter-current type.

Report card. When Site A was audited in 2011, several problems were noted. Most glaring, perhaps, was less-than-minimal monitoring of the water treatment process. Plant operators were unaware of the following:

- The quality of raw water received by the plant.
- Product-water quality (only conductivity was monitored).
- What was occurring within the WTP and inside the ion-exchange vessels.

Bowing to commercial pressures during a period of high demand, the plant owner (1) allowed out-of-spec raw water to enter the WTP and foul demineralizer resin and (2) permitted off-spec demin water to enter the HRSG and coal-fired boilers.

Absence of redundancy was another major issue. There was only one regeneration system for the four demin trains and only one train could be regenerated at any given time. This means that if a failure were to occur in the common system, resin regeneration would not be possible. Water availability would become a major concern if the regeneration system were not returned to service within 24 hours.

Also, with only one degasifier per stage, its contamination would adversely impact both trains of that stage. This makes troubleshooting of the problem train difficult. Online monitoring of the cation effluent, with appropriate chemical limits to trip the demineralizer train, was a simple and effective solution.

Auditors gave the site an unsatisfactory grade for its maintenance practices and absence of critical spares, inability to record process and equipment data for analysis following an upset or failure, and poor training for WTP operators.

Yet another issue: Since installation, the primary cation and anion beds had never been able to consistently rinse down to the required <7 µS/cm setpoint in the rinse recycle step of the regeneration process. The mixed beds from Stage 2 could achieve <0.2 µS/cm, so the train was meeting its quality and quantity requirements specified by the HRSG manufacturer.

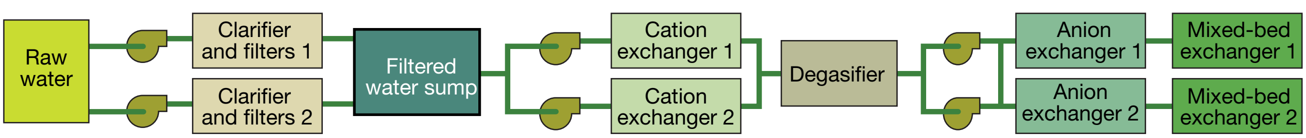
However, it was not meeting its reliability requirements, because the mixed beds were regenerating three to four times more frequently than the original design basis. With the demineralizer train being regenerated six times a week, four-hour mixed-bed regenerations were occurring weekly in Stage 2 instead of every two months. This meant that Stage 2 trains were unavailable for eight hours more each week than they were designed to be. A consequence was that there were times when water having a conductivity greater than 0.2 µS/cm was forwarded to the makeup tanks.

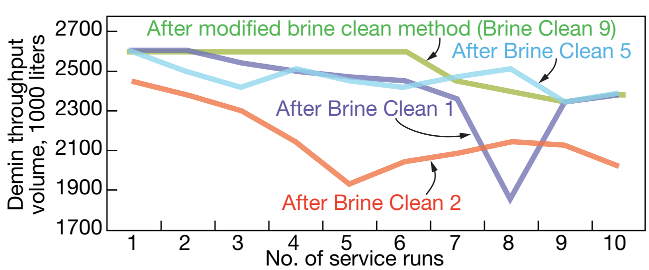
The fixes. The first critical step in fixing the problems was for the plant owner to bring a chemist onboard. The new hire convinced management to stop allowing the WTP to accept off-spec (very high turbidity) water and to stop sending out-of-spec demin water to the makeup tanks. To remove particulate matter that had worked its way through to the anion resin beds, the chemist initiated a regular backwashing program to remove it from the cation and anion resin vessels.

The second step was to introduce more monitoring around the plant for relevant chemical parameters—including turbidity and chlorine ahead of, and after, the multimedia filters, differential pressures across the resin beds, regeneration flows, and chemical concentrations.

Today, when monitors detect feedwater turbidity higher than the design basis of >10 NTU, management switches to the more expensive town water to supply Stage 2 trains until turbidity drops below the design value.

Because the Stage 2 demin-plant supplier filed for bankruptcy, the problem with the cation/anion rinse down was not resolved until after the





B-1. Water treatment scheme was evaluated while installing a new combined cycle at this site. Fresh water from a river exhibited high variability in suspended solids in addition to being high in silica and total organic carbon

B-2. New methodology for brine cleans reduced the rapid decline in throughputs that had been experienced previously. Note that Brine Clean run 9 produced maximum throughput for six service runs after changing resin audit. During the ensuing outage, the manhole plate on the cation vessel was removed and an inspection conducted. The resin was clean, but its level was significantly low. The combination of the loss of inert resin, which increased the freeboard volume, and the low regeneration flows used during the first step of the regen process, meant that the bed was fluidized during regeneration instead of being compacted.

Problem was addressed by adding more strong-acid cation resin to the vessel. Fig A-2 charts the results. Follow-up actions included the replacement and addition of inert resin, as well as installation of resin traps on each vessel to detect any future resin losses.

Although the plant owner still does not have a complete performance management program in place, WTP performance has been improved by monitoring more parameters, conducting more inspections, and assuring accountability and communication of important issues.

Case history B: A success story

Site B was equipped with a 20-year-old conventional coal-fired plant and a new, small simple-cycle gas turbine requiring demineralized water injection. Planning for a 400-MW combined-cycle addition was underway. The site had experienced chemists and dedicated operators for the water treatment plant.

Demineralized water was monitored for conductivity and silica and the plant had a good history for recording problems and such operating information as train throughput volumes, resin change dates and volumes, and water consumption. The WTP had significant redundancy and operated the way designers had intended.

However, the owner had stopped detailed chemical monitoring of raw water supplied to the facility. And O&M parameter monitoring—for example, pressure drops across resin beds, rinse-down times, and instrumentation calibration—was poor. Resin maintenance practices (such as anion brine cleaning) had become ad hoc and an activity of last resort.

The owner reported an increasing number of problems with the plant which demanded a greater amount of troubleshooting time. Coincidentally, as the number of problems increased, plant maintenance was given a lower priority and there often was a backlog of work.

While site preparations were underway for the new combined cycle, WTP capabilities were reviewed. Site B clarified and filtered raw water from a freshwater river supply and the product was fed to two co-currently regenerated demineralization trains—each consisting of cation, stratified anion, and mixed-bed vessels.

The single degasifier serving both trains was located between the cation and anion vessels (Fig B-1). River water had significant seasonal variations in suspended solids as well as high levels of silica (about 20 mg/L) and total organic carbon (TOC, about 5 to 7 mg/L).

A benefit of the WTP review was implementation of a performance monitoring program. The owner started monitoring recommended chemical and operational parameters and began regular resin maintenance and testing. A reliability-centered maintenance (RCM) review was performed with the outcomes from that process used to improve WTP maintenance and reliability.

The PMP has reduced both the number of problems and troubleshooting activities, allowing plant personnel more time for process optimization efforts. Here are a few of the improvements implemented based on PMP results:

- Installation of a TOC analyzer at the outlet of each anion vessel (to help optimize brine-cleaning frequency) and mixed-bed vessel (to measure TOC in makeup water).
- Installation of sodium analyzers on the cation-vessel outlets to help identify the source of high-conductivity events from outside the anion vessel.
- Optimization of brine cleaning methodology.

Regarding the last point, review of historic data indicated that after each brine clean, demineralized water production would increase for one or two service runs and then begin to decline again. Resin testing initiated as part of the PMP revealed that the weak base anion resin was only 41% regenerated after a brine clean.

Using this information, plant management changed the methodology for brine cleans and has successfully reduced the rapid decline in throughputs after each cleaning cycle. Fig B-2 shows declining throughput for runs 1, 2, and 5 immediately after the brine clean. However, after process modification, illustrated by run 9, maximum throughput was achieved for six service runs. CCJ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Judy Weir (judy.weir@thermalchemistry.com) is a powerplant chemistry consultant specializing in the design of new utility water treatment plants and cooling water systems and in the improvement of existing facilities. Training of chemists and operators is another of her responsibilities. Weir has two Bachelor's degrees in applied science (biology and chemistry).

Extracting maximum value from generation assets

Larry Small, chairman of the Combined Cycle Users Group, reports that planning is well along for the CCUG's 2013 Annual Conference, to be held in Phoenix at the Arizona Biltmore, September 3 – 5 (see adjacent sidebar). Presentations and discussion sessions will focus on topics of critical importance to owner/operators of combined-cycle plants, he said. For program details, access the organization's website at www.ccusers.org.

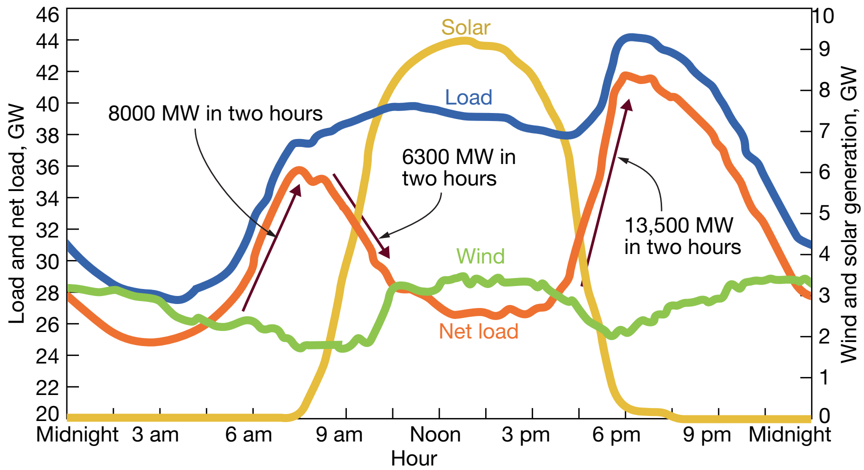
Small also announced two programs launched by the CCUG in conjunction with the COMBINED CYCLE Journal—one to recognize plants that exceed general industry performance expectations, the other to recognize individual achievement. Read more about each on pages 109 and 111, respectively. Finally, the chairman urged users to register as a CCUG member (no charge) at http://ccug.users-groups.com to participate in the group's online forum.

Small, who is director of engineering in Calpine Corp's Engineering & Construction Dept, injected a dose of adrenaline into the opening session on reliability and strategic planning at the 2012 meeting, getting last year's conference off to a fast start. It was held October 16 – 18 at the Orlando area's Buena Vista Palace hotel. Prepared presentations and open discussion provided a snapshot of cycle and equipment design improvements to improve availability/reliability/performance, emerging technologies for fast start/fast ramp, and the challenges associated with integrating renewables and conventional generation.

The renewables challenge

Steve Royall, director of fossil and solar generation for PG&E, and a member of the CCUG Steering Committee, spoke about the demands imposed on conventional generation assets by California's requirement that one-third of the state's kilowatt-hours come from renewables in 2020.

The load profile projected by the California Independent System Operator (CalISO) for January 2020 illustrates the challenge well (Fig 1). Note



1. Load profile projected by the California Independent System Operator for January 2020 (high-load case) illustrates the challenge facing generators in the state

Combined Cycle Users Group

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Details at www.ccusers.org.

Steering committee

Chair: Larry Small, director of engineering, Engineering & Construction Dept, Calpine Corp

Vice Chair: Dr Robert Mayfield, plant manager, Tenaska Virginia Generating Station

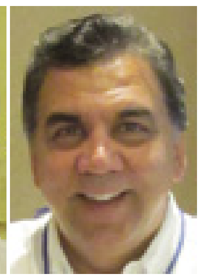
Mike Hoy, senior manager, NUS Construction Projects, TVA

Andy Donaldson, manager of projects, Eastern Operations, WorleyParsons Group Inc

Phyllis Gassert, plant engineer, Ontelaunee Energy Center, Dynegy Power LLC

Steve Royall, director of power generation (fossil/solar), PG&E


Small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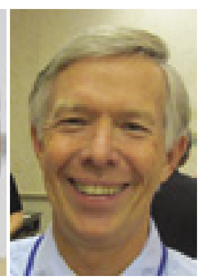

Donaldson


Gassert


Royall

the (1) rapid ramp in conventional generation required in the early morning (8000-MW increase within two hours); (2) the 6300-MW mid-morning decrease as demand levels off and solar generation increases rapidly, and (3) the 13,500-MW ramp in conventional generation required within two hours as the work day comes to an end.

The chart suggests that at least some combined-cycle plants might be forced to start twice daily to satisfy California's requirements. Wear and tear on equipment is only one concern. One attendee asked: "What about the increase in total annual emissions because of the greater number of starts? Will permits be relaxed?" The reply: Still too early to have all the answers. Group think suggested that "operational flexibility" might be an ancillary service in the future because generators must be compensated for withdrawals from their metal-fatigue bank accounts.

More peakers is not necessarily a viable strategy, the 70 attendees concluded. The efficiency of a simple-cycle engine is lower than that of a combined cycle, which contributes to higher emissions.

Royall also shared some details on PG&E's aggressive solar PV program, put in place to comply with the state's renewables statute. In both 2011 and 2012, the company commissioned three facilities totaling 50 MW; three more solar plants with a combined capability of 50 MW are scheduled for service by the middle of this year.

PG&E plans to install a total of 250 MW of photovoltaic capacity before 2016 and contract for another 250 MW as well. The owned PV infrastructure is expected to cost about $1.5 billion. The price the utility receives its solar power is capped at $246/MWh. The solar generation it purchases competitively may not exceed $246/MWh.

Some facts of interest include the following:

- The stationary PV panels installed by PG&E have a guaranteed life of at least 25 years, and an average annual degradation rate of less than 1%.
- PV panels generate electricity best under bright sunshine when the ambient temperature is cool. The spring and autumn months are best for solar generation.
- Solar PV sites require from six to 10 acres per megawatt.

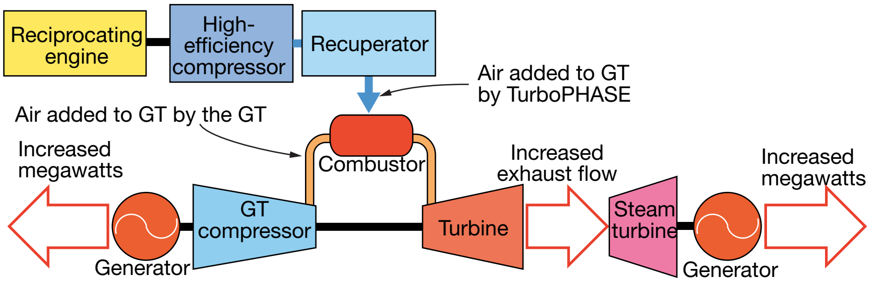
Fast start, fast ramp

Given the demands being placed on generators by grid operators in a regulatory world requiring ever lower emissions of CO, NO_x, and CO_2, it's apparent that most assets on the ground are not optimum. The gas-turbine OEMs have responded with new lines of fast-start/fast-ramp combined cycles powered, in some cases, by the largest and most advanced frame engines available. The vendor offerings look good on paper, of course, but there is virtually no operating experience to date to support at least some claims.

Concerned about flagging orders for new generation, vendors are stoking a fast-start buzz that may at least be capturing the hearts and minds of public officials—if their turnout at the dedication last summer for Northern California Power Agency's Lodi Energy Center is any indication.

Lodi is considered by industry observers as the nation's first generating station designed specifically for fast starting. The nominal 300-MW 1 × 1 facility, a Siemens Flex-Plant™ 30 equipped with an SGT6-5000F gas turbine, is designed to deliver approximately 200 MW within 30 minutes of pushing the start button. It is said to be capable of daily cycling at efficiencies of over 57%.

Getting the electric-power industry to embrace "flexible" generation is critical to the financial success of OEMs. Reason: They likely would provide major equipment for the entire plant—gas and steam turbines, generators, and heat-recovery steam generators (at least in the cases of Alstom, Mitsubishi, and Siemens, which recently pur-



2. **TurboPHASE** essentially is a turbocharger that works on both simple- and combined-cycle plants. It actually improves the efficiency of simple-cycle engines

chased NEM). Otherwise, it might be difficult to hold an OEM accountable for plant performance.

If generation executives are sold on the value proposition of integrated fast-start/fast-ramp plants, it could mean lean days ahead in the US market both for steam-turbine suppliers that do not also offer large gas turbines and for some HRSG manufacturers. Plus, it could put investments in grey-market equipment at risk; and expanded long-term parts/services agreements likely to be part of any flexible-plant sale would reduce the opportunities for third-party services providers.

Startup times for plants like Lodi are reduced by up to 50% compared to conventional combined cycles. Fast-start enabling technologies include a triple-pressure HRSG that incorporates Benson® once-through technology in the HP section, high-capacity steam attemperation, and 100% steam bypass systems. Other features that facilitate fast starts: an innovative solution for warming high-energy piping systems, Siemens' steam-turbine stress controller, and a standby auxiliary steam system to maintain vacuum.

Siemens Energy Inc is the leader in fast-start plant orders—at least based on public announcements received by the editors. Projects in the planning and construction stages include the following:

- A 1 × 1 Flex-Plant 10 at NRG Energy Inc's El Segundo (Calif) Energy Center, scheduled for operation in August 2013. The new plant will burn 30% less natural gas than the units it is replacing. Air cooling enables the facility to shutter its once-through ocean-water cooling system in compliance with California rules.
- Panda Temple Power LLC recently signed contracts with Siemens for two nominal 600-MW, 2 × 1 Flex-Plant 30 combined cycles on one site in Temple, Tex. The four SGT6-5000F gas turbines will have the OEM's Shaping Power ™ feature to enable increased power production on hot days.

The first facility is expected in commercial operation by the end of 2014; equipment purchasing and construction preparations are underway. The order for two Benson-type HRSGs was awarded at the end of July to NEM USA, Greenville, SC. Bechtel Corp was selected as the EPC contractor and is responsible for balance-of-plant equipment.

GE Power & Water's first fast-start combined cycle in the US apparently is several years away. Developer Radback Energy Inc received permission from the California Energy Commission in May 2012 to begin construction of the 624-MW Oakley Generating Station (formerly called Contra Costa). It is expected in service by summer 2016. Published reports say PG&E plans to buy Oakley if it meets operational expectations.

Siemens' success prompted an invitation from Chairman Small to participate in the Reliability and Strategic Planning Session. Jacki Engel, marketing manager for the company's 60-Hz product line brought attendees up to date on Siemens' fast-start offerings. Flex-Plants, she said, are the result of an evolutionary process to create fast, reliable combined cycles that fully leverage the gas turbine's operational flexibility—specifically, fast start, rapid response to load changes, and dependable shut down and restart.


Engel

To illustrate: A nominal 600-MW 2 × 1 Flex-Plant 30 can deliver 300 MW 10 minutes after starting and achieve rated output with steam-turbine valves wide open in less than an hour— provided it has not been offline for more than about 16 hours.

The Siemens 60-Hz Flex-Plant portfolio incorporates eight offerings with ratings from 170 to more than 1200 MW. At the low end is a 1 × 1 configuration incorporating a V84.2 engine. The balance of the product line includes 1 × 1, 2 × 1, and 3 ×1 arrangements of F- and H-class machines.

All of these high-efficiency options are said to cycle on and off and ramp up and down like a simple-cycle engine. Example: A 2 × 1 F-class plant can increase and decrease load at rates of up to 75 MW/min. The portfolio's Clean-Ramp™ feature is said to keep stack emissions in compliance with the permit while load following up to the full ramp rate.

Retrofit solutions. Even if California Governor Jerry Brown were convinced that fast-start combined cycles are the preferred solution for meeting his state's demanding renewables portfolio standard, don't expect generation executives to scrap their existing plants and buy new ones. Rather, many have begun to evaluate retrofit and upgrade alternatives that would allow their plants to provide grid services conducive to a strong balance sheet.

Understanding what owners should consider to keep existing plants competitive was one of Chairman Small's objectives for the keynote session. Many in the industry believe that gas turbines purchased since the bubble, as well as some bought toward the end of that buying frenzy, can handle fast starts and ramps. They also agree that the Rankine cycle is where the real challenges are.

The positive feeling about the gas turbine's operating flexibility was echoed by two participants in the Industry Issues Roundtable hosted by the Combustion Turbine Operations Technical Forum's 37th Annual Fall Turbine Users Conference in mid-September. The CalISO's David Timson said he believed that gas turbines installed in the last 10 years generally would not have a problem meeting the grid's "flexibility" objectives. A clear message he delivered to attendees regarding existing generation that does not now meet the ISO's goals: "retrofit, repower, or retire" (revisit p 80).

Another panelist, Bruce Rising of Siemens, a GT expert, told CTOTF attendees that fast-start engines were developed before renewables integration achieved headline status. He said that the OEMs were sensitive to the need for generators to get their units into service with minimum emissions and fast starts were critical to that goal.

A caution flag went up from the insurance industry's participant in the discussion, Marsh Senior VP Donald Schubert. He said that insurers generally are not enamored of fast starts when they involve "older" combined-cycle plants. "Old" in the insurers' lexicon, Schubert continued, is five or six years.

HRSGs have limits


Craig

The fast-start challenges on the steam side of the plant are obvious to most experienced designers and operators of Rankine cycle equipment. HRSGs, attemperation systems, main-steam and reheat piping, startup drain systems, SCRs, steam seals and vacuum systems, and condensers and their steam dump systems require careful engineering evaluation, and upgrades in some cases, to accommodate the more severe duty. The boilers, in particular, are sensitive to fast starts and ramps.

Small invited HRST Inc's Bryan Craig, PE, to discuss possible boiler design constraints that could adversely impact a given unit's ability to start and/or ramp quickly. Craig began with a review of NFPA purge requirements.

He reminded the group that the HRSG must be purged of combustible gases before the GT is fired. This translates to five changes in the gas-side volume extending from the engine to the point where the turbine exhaust temperature is 100 deg F below the auto-ignition temperature (typically the far end of the HP evaporator).

The engineer said that HRSG design details often are unknown when the purge time is needed by the engine OEM, and a default number is programmed into the control system. For GE 7FAs, the default purge time typically is 15 minutes when only 7 to 9 minutes generally is necessary. A few hours of engineering effort is all that's generally required to calculate the purge requirements for a given unit and make the necessary control-system adjustments.

You can save even more time on a startup if your gas turbine is equipped to burn only natural gas and the HRSG is not capable of supplementary firing. By purging on shutdown rather than at startup, the time required for your next start can be reduced by as much as 15 minutes.

An engineering evaluation of drum-level controls was recommended by Craig. Recall that the rapid increase in steam production during a fast ramp causes drum-level swell. If carryover occurs, a unit trip is possible. IP drums are particularly susceptible to carryover because of their relatively small size.

For fast-start units, Craig recommended the use of three-element control with a moving set point, and minimum flow through the feedwater control valve, to help automatically manage swell while maintaining economizer flow with minimal operator intervention. He suggested that users not shy from using intermittent blowdown to reduce drum water inventory when necessary.

Fuel-gas heater permissives were next on Craig's list. He reminded: Some gas-turbine OEMs require fuel-gas heating to meet NO_x guarantees and assure emissions compliance. Water from the IP economizer outlet typically is used as the heat source for this purpose. Permission to increase load is obtained once fuel gas is 300F.

But, in some piping schemes, the IP drum pressure must exceed the condensate discharge pressure (275 to 325 psig) before water can flow through the performance heater. In those instances, moving the feedwater control valve from upstream of the IP economizer to downstream of it will allow water flow through the heater and enable startup to proceed faster.

However, this requires the IP economizer to operate at a higher pressure than what it was designed for. An engineering study is necessary. If the location of the feedwater control valve can be changed without replacing pressure parts, recertification of the economizer is required by the *ASME Boiler & Pressure Vessel Code.*

Steam-turbine temperature matching is another possible issue. The startup time for the gas turbine may have to be extended if the steam temperature leaving the HRSG exceeds steam-turbine warm-up requirements. In many instances, the desuperheater cannot provide the level of temperature control required and a GT hold is necessary.

Ways to minimize the probability of a mismatch, Craig said, include the use of electric blankets to heat the steam turbine prior to startup and/or installation of an air attemperation system to control steam temperature independently of GT load.

The HP drum can suffer fatigue damage when pressure changes quickly because of the resulting temperature gradient across the vessel wall. Specifically, the inside of the drum quickly tracks changes in saturation temperature while the outside wall requires "soak" time to come to the new temperature. If the temperature differential is too great, the resulting stresses can initiate cracks at discontinuities such as large nozzles.

Craig said HP drum nozzle cracks are surprisingly common in HRSGs that cycle and that weld design is a contributing factor. It is possible to mitigate cracking by grinding out existing partial-penetration nozzle welds and replacing them with full-penetration welds of either the pass-through or set-on type. However, this work is difficult, expensive, and time-consuming.

There are several ways to protect steam drums against harmful thermal stresses. One is installation of a monitoring system that alarms on high drum stress based on measured temperature differentials, enabling you to slow-down the startup process or ramp rate. Another is a steam sparging system to keep the drum warm and pressurized while the unit is offline, thereby reducing the temperature differential that accompanies a startup.

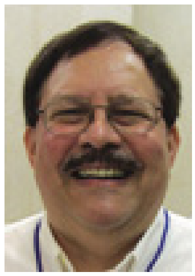
Another corrective action is to control the HP-drum pressure ramp independently of the GT startup rate. But to accomplish this you need somewhere for the steam to go. A full bypass system that routes superheater outlet steam via the cold-reheat line, reheater, and hot-reheat line to the condenser is one approach. Another is to use sky vents. One negative associated with the latter is the loss of costly demineralized water.

Get more from your GT with an engine

The discussion on emerging technologies for fast start/fast ramp during the Reliability and Strategic Planning Session was the perfect segue for Bob Kraft, founder/CEO of PowerPHASE LLC, to introduce to the CCJ editors, during the ensuing coffee break, the company's latest product—TurboPHASE™.

He said it can boost the output of a combined-cycle plant by up to 15%, and a simple-cycle gas turbine by up to 20%. This is achieved by addition of a skid-mounted assembly, consisting of an efficient reciprocating natural-gas or diesel engine and an intercooled compressor, which injects hot high-pressure air directly into the combustion section of the GT, thereby increasing mass flow through the turbine.

The additional power is available within a minute or so of starting the auxiliary engine, the former PSM founder and president said. For a 7FA.04-equipped 2 × 1 combined cycle, a 5% TurboPHASE injection into each gas turbine means more than 40 MW is available (18 MW from each GT, plus 5 MW from the steamer) almost instantly. It can be used to (1) compensate for the sharp drop in power output experienced by some intermittent renewable resources during sudden changes in weather, and/or (2) provide a dispatchable source of peaking power.


Eisenbise

The amount of air injected into a given gas turbine is determined by an engineering study that considers specific limits of plant equipment—such as the GT, generator, transformer—as well as the ambient range for which the extra power is desired. Typically, the equivalent of from 5% to 10% of compressor inlet air can be added in the combustion section.

TurboPHASE evolved from the company's work aimed at developing efficient, grid-scale modular compressed-air storage packages that Kraft believes will have international application where and when energy storage is better appreciated. But the value of the system to generating companies today goes well beyond its inherent ability to back up intermittent renewables and to enhance the value of existing gas turbines for peaking duty.

Specifically, it is a less costly and more efficient alternative than steam injection and air inlet chillers for increasing combined-cycle output and performance on hot days. Kraft said that the use of steam injection and inlet chilling can match the GT power boost of his "turbocharger" but those alternatives reduce steamer output and increase parasitic power consumption, penalizing both total output and heat rate.

TurboPHASE has no effect on base-load combined-cycle efficiency, running or not. The heat rate of the TurboPHASE incremental power on such a unit is substantially better than any simple-cycle gas turbine available—and it actually improves the efficiency of simple-cycle engines.

When asked about other options for quickly boosting output, Kraft shared his thinking on fogging and duct burners. Fogging, he admitted, was an efficient way to increase power, but the experienced jet-engine designer said the amount of additional output is limited. Likewise, duct burners can add peak power but there's an efficiency penalty.

Regarding emissions, the engine can be equipped with an SCR and an oxidation catalyst to hold NO_x and CO emissions, respectively, within permit limits. Alternatively, the recip's exhaust can be injected into the GT exhaust stream to use emissions control solutions provided with the gas turbine.

High-energy piping

Harry Eisenbise, a senior mechanical engineer for WorleyParsons, brought attendees up to date on materials qualified for high-energy piping systems. Owner/operators still reeling from P91 issues appeared to breathe a sigh of relief when they learned that P92, one option for main-steam and hot-reheat systems, does not yet have widespread support in the US.

High-energy fluid systems get regular in-depth coverage at CCUG meetings, the only user group to do so. In 2011, Dr David Buzza, a senior engineer (metallurgist) for AEP walked owner/operators through P91 piping fabrication guidelines, stressing verification of as-received material quality and the importance of post-weld heat treatment (PWHT). In the same session, Jonathan McFarlen of M&M Engineering Associates showed users how to conduct a meaningful assessment of their high-energy piping systems. Access presentations from 2011 and 2012 at www.ccusers.org.

Eisenbise said the materials of choice today for main-steam and hot-reheat piping were P91 and P92 seamless alloy steel. Seamless and welded carbon steel (Grades B and C), and seamless and welded P11 alloy steel, are the options for cold-reheat and extraction-steam piping, with P22 an additional choice for the latter. Seamless carbon steel (Grades B and C) also is specified for feedwater discharge piping. Materials choices for the auxiliary steam system are seamless carbon steel (Grade B) and seamless P91 and P22 alloy steel pipe.

Next, the senior engineer reviewed the properties and status of the two most sophisticated materials for high-pressure/high-temperature powerplant applications. P91, a modified 9% chromium/1% molybdenum alloy steel, was developed in the US more than 30 years ago and is qualified for use in both new and retrofit piping-system applications.

P92, which most attendees were not familiar with, is a modification of P91. It contains 1.5% to 2% tungsten and typically has only one-third to one-half of the molybdenum used in P91. P92 was designed primarily for piping systems in advanced supercritical coal-fired plants and is viewed as a major improvement on P91, Eisenbise said, with a rupture-strength advantage (allowable stress values) of approximately 16% to 30% over the older material at operating temperature.

Both P91 and P92 are known as creep-strength-enhanced ferritic steels. They differ from the P11 and P22 materials most familiar to powerplant personnel in that their properties derive from a specific condition of microstructure, rather than from the chemical constituents of the materials. The downside of this is that manufacturing and fabrication processes must be controlled very carefully to ensure that the appropriate microstructure is achieved, failing which the material will suffer a significant reduction in its creep-strength properties. AEP's Buzza focused on this in 2011.

Eisenbise then put up a slide listing the following as the advantages of both P91 and P92:

- High creep-rupture strength (allowable stress).
- Excellent toughness.
- Lighter weight because of significant wall-thickness reductions compared to P22. Example: For an 18-in.-OD main steam pipe with design conditions of 4025 psig/1065F, P22 would require a 4.5 in. wall, P91 only 2.5 in.—in round numbers.
- Higher temperatures.
- More flexible piping systems
- Lower support weight.
- Lower loads at terminal points.

Disadvantages of P91 and P92 compared to P22 are these:

- Higher cost of pipe, fittings, and valves.
- Unforgiving material if proper processing steps are omitted or missed.
- Longer lead times for processing during fabrication and erection, and heat treatment both for bends and welds.
- Weld filler material more expensive and less available.

Comparing P91 to P92, the cost of piping, fittings, and valves is higher for the latter; plus the newer material has no meaningful operating history in the US. Regarding prices, Eisenbise said the cost last fall for P91 was between about $3.17 and $368 per pound; P92 was approximately $4.10/lb.

P92 US experience in main-steam and hot-reheat systems is limited to Unit 4 at Wisconsin Public Service's Weston Power Plant where P92 main-steam piping has been in commercial service since June 2008. The John W Turk Jr Power Plant, in the final stages of construction by AEP subsidiary Swepco, has a P92 main-steam system with a design temperature of 1115F. Offshore, experience with P92 is growing in Europe, Japan, and China. Field reports indicate that some users have expressed concern about cracking of welds and "soft areas" in the piping. Sound familiar?

Lead times for P91 and P92, as well as for carbon steel, are relatively short today compared to only a few years ago, the speaker noted. Suppliers can have P91 pipe at fabricators' shops in four to five months after order placement. Adding four months for fabrication means pipe can be on the job site ready for installation in eight to nine months following receipt of a purchase order—or in one-third the time it would have taken in 2009.

Eisenbise devoted a considerable portion of his podium time to welding. Here are the key points he made:

Weld filler metal. Specify in your

purchase order that *actual*—not *typical*—test reports be provided with *all* consumables.

- For P91 and P92, incorporate the following in your specifications:
  - Nickel plus manganese content of the filler metal not exceed 1.5%. These constituents affect the lower critical temperature of the filler material: The less nickel/manganese, the higher the LCT.
  - Nickel not to exceed 0.4%.
  - Manganese-to-sulfur ratio greater than 50.
  - Nitrogen controlled to 0.02% minimum.
  - Minimum toughness of the filler metal after PWHT of 20 ft-lb at 70F.
- Purchasing premium filler metal is only the first step in the development of a program for maintaining the quality of your consumables until they are used. Tight control of electrodes is vital for preventing inadvertent contamination that can compromise weld quality.

Hangers and supports. Weld hanger/support attachments to the pipe in the fab shop—including all trunnions, lugs, etc . The majority of these welds will require PWHT and nondestructive examination (NDE), both easier to do correctly in a controlled shop environment.

Welding processes. Shop fabrication generally allows you the flexibility to choose from among GTAW, SMAW, gas metal arc (GMAW), flux cored arc (FCAW), and submerged-arc (SAW) welding processes. In the field, you generally are limited to GTAW and SMAW.

Preheat. Proper application and maintenance of preheat are critical to welding success. For P91 and P92, you must maintain a maximum inter-pass temperature of 600F. For other alloys, the welding procedure will specify the maximum inter-pass temperature.

Bake out is an intermediate post-weld heat treatment for P91 and P92 wherein the weld is heated to 500F to 600F and held for a period of time depending on weld thickness, and then slow-cooled. It is used at the completion of welding and when welding is interrupted, and is followed by wrapping of the weld with insulating material.

PWHT for P91 and P92 must be conducted at 1375F to 1425F—no exceptions.

Terminal-point welds. A subject covered by Eisenbise usually omitted by most speakers addressing welding of high-energy piping systems was terminal-point welds. He stressed that welds at equipment—such as the heat-recovery steam generator and steam turbine—require close attention.

The size, minimum wall thickness, weld end preparation, and most importantly, the material at each terminal point, must be totally understood and evaluated to assure a successful pipe-to-equipment weld. It is entirely possible, he continued, that transition pipe sections may be required between the main-steam and hot-reheat lines and the turbine connections. Eisenbise described transition pieces as reducers that accommodate the change in diameter and wall thickness between the equipment terminal point and the main pipe run.

It is common, he said, for the terminal-point material to be a proprietary alloy—particularly on the turbine. The OEM typically classifies its material as "*similar to* Alloy XXX," which means engineering and metallurgical studies are required on the part of the plant owner's team to develop an acceptable welding procedure specification.

Gauge steam-cycle health

Deck-plates personnel generally recognize the importance of good water chemistry; however, relatively few have a high level of comfort with the subject. But when Dan Sampson, one of the industry's top water experts, talks, they listen. Perhaps that's because the WorleyParsons consultant began his career as a nuclear-plant operator and understands first-hand the practical information needs of a proactive O&M team.

Sampson's message for attendees was simple: Monitor corrosion-product transport (read "iron") both to protect equipment—such as condensers, condensate/feedwater system, heat-recovery steam generators, and steam turbines—and to gauge the effectiveness of your plant's cycle chemistry program. The data collected enable operations and chemistry personnel to identify deviations from control specs, allowing prompt corrective action as well as continuous process improvement.

The water consultant then explained how to develop an effective program for monitoring corrosion products, addressing sample locations and limits, sample frequency, recommended tests, and data interpretation. Here's a summary of what he said:

Sample locations and limits. Sampson put up on the screen a one-line cycle diagram identifying the preferred locations for iron monitoring as downstream of the condensate pump (before and after polishers/filters, if equipped) and in the LP and HP drums of the HRSG. Monitor the rotor air coolers as well, he said, if your combined cycle has them. Recommended iron limits: Less than 2 ppb in the condensate/feedwater system and LP steam drum; less than 10 ppm in the HP drum.


Sampson

Guidelines for sampling include the following:

1. Sample lines should be made of 0.250- to 0.375-in.-diam stainless steel tubing.
2. Sample water must run continuously and at 4 to 6 ft/sec. Otherwise the sample will not be meaningful.
3. Sample lines should be as short as practicable, to minimize both lag time and iron loss by deposition on the tube's internal surface.
4. Samples should be cooled to less than 90F.

Frequency. Following unit starts, Sampson suggested sampling every 15 minutes for the first six hours, or until iron levels stabilize. He explained that monitoring during startups and shutdowns was particularly important because crud bursts—the sudden release of corrosion products from surfaces exposed to water/steam caused by thermal, chemical, and/or hydraulic shock—were more likely during transients. This was obvious from a plot of iron concentration versus time following startup (Fig 3). After resuming "normal" operations, Sampson suggested daily sampling at all locations until results are sufficiently consistent to support a longer interval.

Recommended tests. Run tests for total, soluble, and suspended iron, once or twice daily, until you accumulate the 30 to 60 data sets (the latter preferred) suggested for meaningful analysis and trending, Sampson said. He pointed out that soluble iron exists only for moments and test frequency can decrease to monthly if the baseline test results are consistently below detectable limits. The frequency of the wet total-iron test can be weekly if results are consistent with those from suspended-iron tests described below. Note that wet tests require use of a spectrophotometer.

Sampson presented a table of methods for monitoring iron. It showed that the minimum detection limits for most tests are 10 ppb and above—too high for powerplant use. The Millipore filter (0.45-micron filter) test for suspended iron is more accurate than wet tests, the consultant said, for two primary reasons: (1) Wet test methods don't accurately measure total iron in steam drums. (2) Iron changes form and does not show up on the traditional wet tests unless digested.

The concentration of iron oxide (Fe_3O_4) in parts-per-billion terms has a detection limit of 10 ppb for the 1-liter sample specified by the Millipore filter test, which relies on a visual comparison of filter results and a calibrated printed chart. This comparison is similar in nature to the micro-Ringelmann smoke chart used by boiler operators before EPA was formed. To achieve the 2-ppb limit required, a 5-liter sample is drawn. However, this much water requires a vacuum pump and filter assembly to run the test.

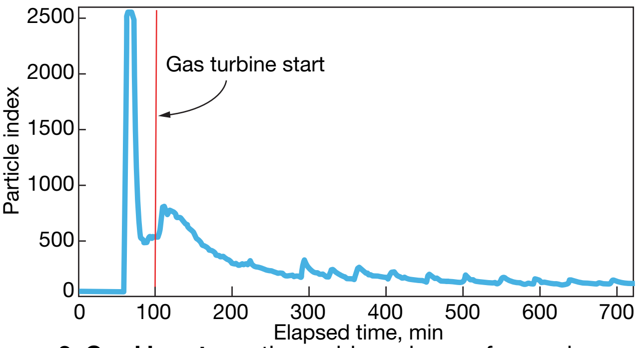
Composite sampling uses the same 0.45-micron filter, but offsite analysis provides greater accuracy. Here's how it works: A known volume of water passes through the filter and corrosion products accumulate. The filter is removed and weighed after exposure. The result is given in milligrams or micrograms per liter.

Additional analyses—such as x-ray diffraction—can provide information on oxide composition. Sampson recommended that soluble and total iron be analyzed by an outside lab quarterly to confirm the accuracy of plant tests. He stressed the importance of preserving samples to ensure accuracy.

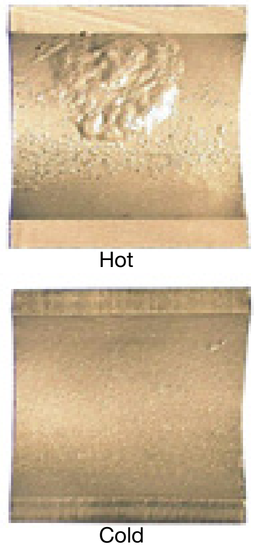
Particle analysis. Wet-test results are valuable, Sampson continued, but they leave significant holes in the data stream. Every thermal, chemical, and hydraulic event liberates or produces metal oxides in the steam system. These events occur often and randomly and the majority of them cannot be detected by time-based iron sampling as described above. However, particle analysis provides a window into metal liberation and transport as it occurs (real time). Two different technologies can be used:

1. Particle counters count the number of particles in different size ranges. Testing indicates that the majority of iron transport occurs as particles smaller than 5 microns.
2. Particle monitors provide only one reading—a so-called index representing the total surface area of all particles passing through the sensor.

Deposit weight density is another analytical method at your disposal, Sampson told the group. It requires a tube sample from the first row of the HP evaporator. The sample is sliced in half longitudinally, separating the cold side of the tube from the hot side (Fig 4). Each side is weighed, cleaned, and reweighed. The difference is deposit weight density. Results are used to determine if the boiler should be cleaned.



3. Crud bursts, or the sudden release of corrosion products, occurs during transients, such as startup



4. Sample from first row of the HP evaporator is sliced longitudinally, separating the cold and hot sides of the tube. Each side is weighed, cleaned, and reweighed. Difference is used to determine if the boiler should be cleaned (right)

In wrapping up his presentation, Sampson said that combining particle counts with wet test results "closes the loop" on Rankine cycle metal transport. The combination offers these three windows into the process:

1. Wet tests correlate particle index to iron transport.
2. Particle index provides real-time, continuous indication of the amount of iron moving through the system.
3. Deposit weight density confirms the amount of deposition on the tubes.

He finished by urging users to reduce corrosion-product formation by minimizing oxygen ingress, suggesting nitrogen blanketing of steam drums and the demin-water tank during shutdowns as well as steam sparging of the hotwell.

Controls, cybersecurity

The session on control systems and cybersecurity featured a presentation on security risks by Daniel Noles, TVA's manager of controls engineering support. You can access Noles's slides at www.ccusers.org. The follow-on discussion produced several observations and aphorisms worthy of note, including the following:

- Plant operators are the industry's most powerful assets. The job of the control system is to enable the operator to make the right decisions, at the right time, to achieve identified goals. The simpler you can make the control system, the better.
- Plants have a mixture of legacy and modern control systems. The former don't have the communications capabilities and security of new equipment and those vulnerabilities must be addressed.
- Alarm management is a big challenge. However, it takes relatively little effort to have a large, positive impact on operations by eliminating alarms not of primary concern.
- Tracking startup and shutdown data can identify abnormalities worth correcting.
- Advanced pattern recognition: Early detection of impending problems offers considerable benefits. This technology is worth investigating.
- It's easy to make information available, but how do you make it more understandable and useful to the people who need it? Those who can answer the question will reap rewards.
- NERC CIP standards 2 through 9 are relatively immature compared to other regulations the industry has to deal with. Version 4 is on the way but will not remain in effect for long; V5 is promised by late 2014. Possible wrinkle: Dept of Homeland Security, sources say, may supercede DOE as the CIP watchdog agency. Stay tuned.
- The risk of being labeled "non-compliant" may be reducing the focus on security. At least some observers say, "how to comply" seems to have taken precedence over "security." Reason: "Failure to comply" makes the news and initiates fines. There must be a balance between compliance and security was the attendees' view. A cybersecurity program that achieves both compliance and security goals begins with people, users generally believe. Example: Don't be tempted to pick up a USB stick in the parking lot and put it in a plant computer.
- Technology leverages the process and people. The most complex decisions should be made by people; technology assures repeatability.
- Success in control-system decision-making and cybersecurity initiatives requires a champion with the ability to explain complex technical issues to executives. CCJ

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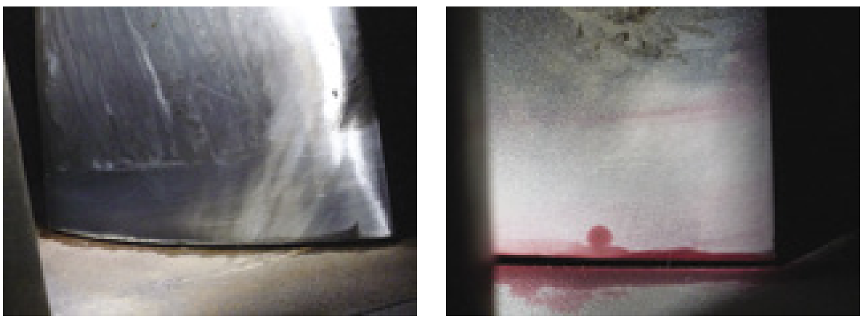
Tip grinding may not cure R1 blade-tip distress on 7FA compressors



1, 2. R1 blade for 7FA compressor after tip grinding is at left; dye bleeds from microscopic cracks attributed to grinding at right

Tip rubs generally are considered the most common cause of R1 blade-tip distress in 7FA compressors. Such distress can lead to radial tip cracks (leading and trailing edge) and tip liberations with significant collateral damage to forward and aft compressor stages. This is not news, as a review of TIL 1509-R3 indicates. But what is news, Mike Hoogsteden, field service manager for engine inspection experts Advanced Turbine Support LLC, told the editors, is that cracks are appearing more frequently than in the past.

Ten inspections last summer revealed cracks in three 7FA 7241s, Hoogsteden said. He is not sure that the tip grinding "fix" supported by the OEM is the answer. The tip grinding profile illustrated in Fig 1, he pointed out, is not as "clean" as you might expect and the results of the dye-penetrant inspection in Fig 2 reveal a crack in the circular indication (invisible during conventional visual inspection). The ATS service manager attributes the increased frequency of cracking to more aggressive operation than GTs generally experienced in the past.

Hoogsteden next pointed to the 1509 recommendation that after repairs, blades should be inspected at 25, 50, and 100 actual starts. He believes that users often don't understand the intent of the recommendation and offered this explanation: If you identify a flaw during your 50-start inspection, after repairs are complete your next inspection is following 25 starts, not 50 as many believe. In effect, the inspection cycle starts again after any repairs are made.

Hoogsteden said that turbine owner/operators had gotten used to doing borescope inspections once or twice annually. But, he suggested that inspection frequency increase because engines are running longer and harder than they had been operating previously. Maintenance issues are not only associated with the 7FA, Hoogsteden noted. Issues with 501F transition pieces, he continued, are occurring more frequently as well.

Believe it or not: Steam drain lines can overheat

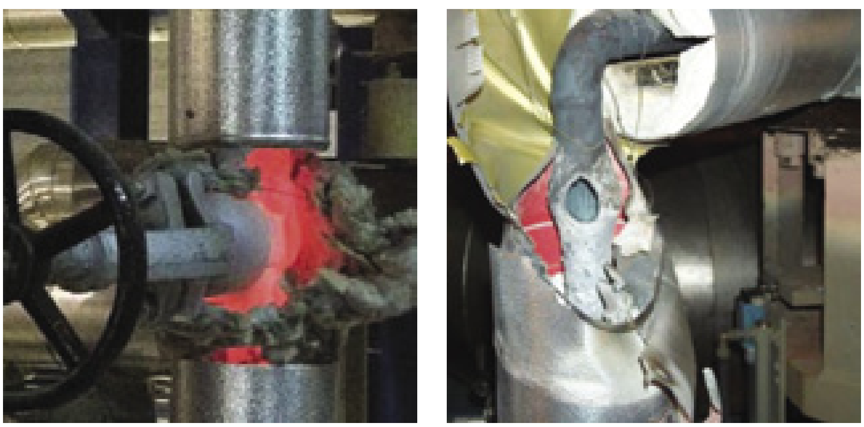
A steam-turbine OEM released a safety bulletin last summer warning of possible localized overheating of drain piping and valves. Pictures incorporated into the bulletin showed a ruptured steam drain and a glowing (cherry red) isolation valve. Consensus view of several knowledgeable engineers: The condition described was not specific to any given OEM and that it possibly could occur as well in steam drains other than those on the turbine. However, no users the editors spoke with about the phenomenon had first-hand knowledge.

Overheating events acknowledged in the bulletin had occurred on four of the OEM's steam turbines, both during commissioning and turbine startup. During commissioning, the drain-leg piping and open manual isolation valve, located just upstream from the closed motor-operated drain valve, were much hotter than the steam. An overheating event experienced during turbine startup occurred in a combined cycle when one of the two stop/control valves did not open during loading of the steam turbine and a section of drain piping was damaged.

Indicators of possible overheating include cherry-red pipes and valves, deteriorated or burned pipe insulation, and thermocouples reporting temperatures significantly above that of the steam. The bulletin noted that the condition may be mitigated by cracking open the motor-operated drain valve downstream of the isolation valve to establish a small amount of steam flow through the drain line.

Public discussion among owner/operators and others revealed the following:

- The phenomenon had occurred previously (at least one occasion) when a piece of slag became trapped in a tee section of dead-legged pipe. The vortices caused by the tee caused the slag to spin continuously until the pipe got red hot in that region.
- A user suggested that an acoustic resonance, or a vortex, that traps energy in the dead leg might be the cause. This person said he had seen



3, 4. The glowing isolation valve (left) and ruptured drain (right) confirm an overheating event the phenomenon modeled in a lab, but not in practice.

- An expert on heat-recovery steam generators reported having seen drain lines inside the boiler casing hotter than the bulk steam temperature because of additional heat contributed by exhaust gas bypassing the superheater. This can be avoided, he said, by passing a controlled amount of steam through the drain lines.
- Another engineer likened the damage mechanism to FAC, except that the velocity of the oxides or debris in the pipe swirls around so fast it creates friction.

Calpine has a good year, to buy back more shares

Most CCJ readers have little interest in financial statements published by power generators, but Calpine Corp's annual reports offer much more than numbers. CEO Jack Fusco summed up what engineers understand best with this statement: "2012 was a breakout year for Calpine, as we capitalized on the secular shift toward greater utilization of combined-cycle gas turbines. . . . We achieved record operating results, generating 116 million MWh—23% more than last year. The increased generation was primarily due to our excellent powerplant operations and unprecedented coal-to-gas switching. Overall, our business continues to be resilient across a wide range of natural-gas prices."

More good news for the company was that plant personnel were able to reduce the cost of major maintenance and hold plant operating expenses essentially flat. Fusco attributed this to continued focus on operational excellence and preventive maintenance. The result: The company's lowest-ever annual forced-outage factor—1.6% fleet wide.

Highlights in asset management included the sale of the 847-MW Broad River Energy Center peaking facility in South Carolina for $504/kW and the 603-MW combined-cycle Riverside Energy Center in Wisconsin for $667/kW; purchase of the 800-MW Bosque Energy Center combined cycle in central Texas for $540/kW; and plans to bring online about 1600 MW of additional gas-fired capacity in California, Texas, and Delaware over the next 30 months.

After adding in new long-term contracts for more than 2100 MW, the good news amounted to a surplus of $1 billion at the end of 2012, enabling a hefty increase in Calpine's share repurchase program.

Notable achievements in power operations for 2012 included the following:

- Maintained stellar safety metrics. Plants recognized for 10 years of service with no lost-time accidents included the Westbrook, Pine Bluff, Baytown, Zion, Tasley, Missouri Avenue, Crisfield, and Bayview Energy Centers; plus, the Geysers plants Aidlin, Sonoma, Cobb Creek Quicksilver, and Socrates.
- Starting reliability, fleet-wide was 98.3%.
- Capacity factor of combined-cycle plants increased to 52.3% in 2012, up from 42.6% in 2011.
- Top producer was the Deer Park Energy Center, which generated 6.2 million MWh in 2012, the most by any individual plant in fleet history.

Development projects include these:

- Russell City Energy Center, a 429-MW (net-interest base-load capacity) combined cycle is expected in service this summer. Calpine holds a 75% share in the facility, which has a 10-year power purchase agreement (PPA) with PG&E.
- Los Esteros Critical Energy Facility, a 4 × 0 LM6000-based peaking plant, is being repowered as a 309-MW combined cycle. It also has a PPA with PG&E and is expected in service this summer.
- Channel and Deer Park Energy Centers in Texas each are being expanded by approximately 260 MW. COD for both is expected in

summer 2014.

- Garrison Energy Center, a 618-MW combined cycle, will be built in two equal stages. COD for the first stage is expected by the summer of 2015. The air permit is in hand.
- Turbine modernization program. Through the end of 2012, Calpine had upgraded 11 Siemens and eight GE turbines, adding 200 MW of capability. At least three more projects are planned.

NV Energy: New assignments, EEI award

NV Energy has strategically repositioned the top engineers in its generation department to streamline the organization for economies in operation and maintenance consistent with VP of Energy Supply Kevin Geraghty's demanding goals for world-class performance.

Dariusz Rekowski, formerly director of O&M, moves into Geraghty's old position as generation executive, vacant since the latter was promoted last fall. Brian Lawson, who has had a wide range of management responsibilities since joining the company in 1985, takes over Rekowski's former office. Additionally, Peter Steinbrenner is promoted to director of generation engineering; Bill Simko is named director of special projects.

These five top managers are known to many readers for their insightful presentations and volunteer work on behalf of the industry's user groups—especially CTOTF™, Combined Cycle Users Group, Southwest Chemistry Workshop, and the Air-Cooled Condenser Users Group, which Geraghty's team founded five years ago.

Meanwhile, out at the Arrow Canyon Complex, about 45 minutes from headquarters, Director Steve Page announced new responsibilities for his team members to enable the integration of activities at the four 2 × 1 F-class combined cycles he manages (two at Chuck Lenzie, one at Silverhawk, and one at Harry Allen) into one operation.

Ron McCallum is now production manager for asset management, responsible for work planning and long-term equipment health; Forest Hawman is production manager for strategic issues and other ongoing programs and activities; and Shane Pritchard is production manager for tactical issues, including plant operations and routine maintenance execution.

NV Energy's Fort Churchill Generating Station, a 226-MW gas-fired steam plant in Yearington, Nev, was honored recently by the Edison Electric Institute with the organization's *Safety Achievement Award* for 25 years of operation without a lost-time accident. To put the achievement in perspective, the last lost-time accident occurred at Ft Churchill on Mar 30, 1987, when Ronald Reagan was president and a gallon of gasoline cost less than $1.


Geraghty


Rekowski


Lawson


Steinbrenner


Simko

Over the years, the plant has embraced more than 1500 safety suggestions, which surfaced through safety audits, safety committee recommendations, and individual contributions.

Briefs

NAES Corp, Issaquah, Wash, announces that Robert E Fishman has been named president and CEO. The industry veteran probably is best remembered by readers of this publication for his time at Calpine Corp as VP operations, engineering, and development and as president of PB Power Inc.

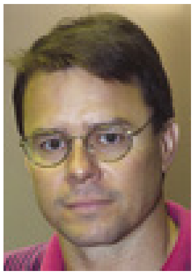

Fishman

In related news, Tony Downey is appointed director of safety for maintenance and construction for the company, based in Pittsburgh.

ThermoEnergy Corp, Worcester, Mass, appoints James F Wood, former deputy assistant secretary for DOE's Office of Clean Coal, president and CEO. He was subsequently elected board chairman. Before moving to Washington, Wood had been president of Babcock Power Inc, Babcock & Wilcox Co, and Wheelabrator Technologies. He also has authored several articles for the CCJ over the years.

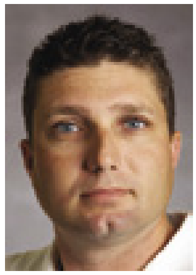

Wood

Associated Electric Cooperative Inc, Springfield, Mo, announces the promotion of Gabriel Fleck to manager of gas plant operations. He takes over for Bob Pasley, who retired. Fleck is best known to most CCJ readers for his tireless work as chairman of the 501D5-D5A Users.


Fleck

Turbine Generator Maintenance Inc, Cape Coral, Fla, a third-party provider of inspection, maintenance, and repair services for steam and gas turbines, announces organizational changes to support its continued growth. Mark Sherrill is appointed director of steam turbine/generator services. In his former life as a user, Sherrill was a regular participant in meetings sponsored by the Western Turbine Users Inc and the 7EA Users Group. He was a member of the latter's steering committee for a few years.


Sherrill


Irvine


Hamilla


Haralson

Ben Irvine is named director of generator services and David Hamilla director of gas turbine services. Ray Haralson is promoted to president of TGM Servicios Limitada, Concepcion, Chile. David Branton continues as the company's CEO.

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