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CCJ COMBINED CYCLE Journal

Best Practices Awards for 2013

Newington Energy LLC
Fast Starts

Encogen Generating Station
Fast Starts

Newington Energy LLC
Operation and Maintenance

Effingham County Power
Performance Improvements

Johnson County Generation Facility
Performance Improvements

Klamath Cogeneration Plant
Performance Improvements

Effingham County Power
Workforce Development

NV Energy Fleet
Workforce Development

Plants sharing their Best Practices

W.T.U.I.

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

Sharing Best Practices

More than three dozen generating stations participated in the 2013 Best Practices Awards program sponsored by the **CCJ** in conjunction with the Combustion Turbine Operations Technical Forum™, which hosts the recognition luncheon and provides judges from among the members of its leadership council.

As you read through the entries, which are arranged by plant this year rather than by subject category (safety, environmental stewardship, design, etc) to more appropriately recognize the staffs of these facilities for their accomplishments, be sure to look beyond the "headliners." While the plants with entries recognized by the judges as Best of the Best are at the front of the special section, beginning on p 25, the ideas of greatest value to your plant may well be among those voted Best Practices Awards or given a "thumbs down" by the judges. Anyone who watches professional sports knows, referees, umpires, and judges aren't necessarily correct on every call.

The editors believe there were several "missed calls" in this year's judging. Be sure to read the idea for wireless monitoring of HRSG drain valves submitted by Bill Vogel's team at Granite Ridge Energy (p 65); the re-engineering of an air-inlet house by Rene Villafuerte's engineers at CCC Saltillo to extend the interval between filter change-outs (p 69); the gas-line venting system employed by Brad Hans' team at Terry Bundy Generating Station to assure a safe working environment (p 87); and NV Energy's steam-line drain valve inspection program to improve reliability and safety (p 97).

You might even want to judge the entries yourself and share the results with the editors; we'd welcome the opportunity to publish your thoughts. Use the scorecard and methodology described on p 91 to facilitate this effort. Finally, it's not too soon to begin thinking about the 2014 Best Practices that you might want to share with industry colleagues; entries are due December 31 (p 104). Your plant and coworkers deserve recognition for their efforts and successes.

User group meetings, July – December 2013

July 15-18, Southwest Chemistry Workshop, Phoenix, Tempe Mission Palms Resort and Convention Center. Contact: David Bollinger, 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.accusersgroup.org. Registration/sponsorship contact: Sheila Vashi, sv.eventmgt@gmail.com. Speaker/program contact: Dr Andrew Howell, chairman, andy.howell@xcelenergy.com.

October 22-24, 7EA Users Group, 2013 Conference and Vendor Fair, Monterey, Calif, Hyatt Regency Monterey. 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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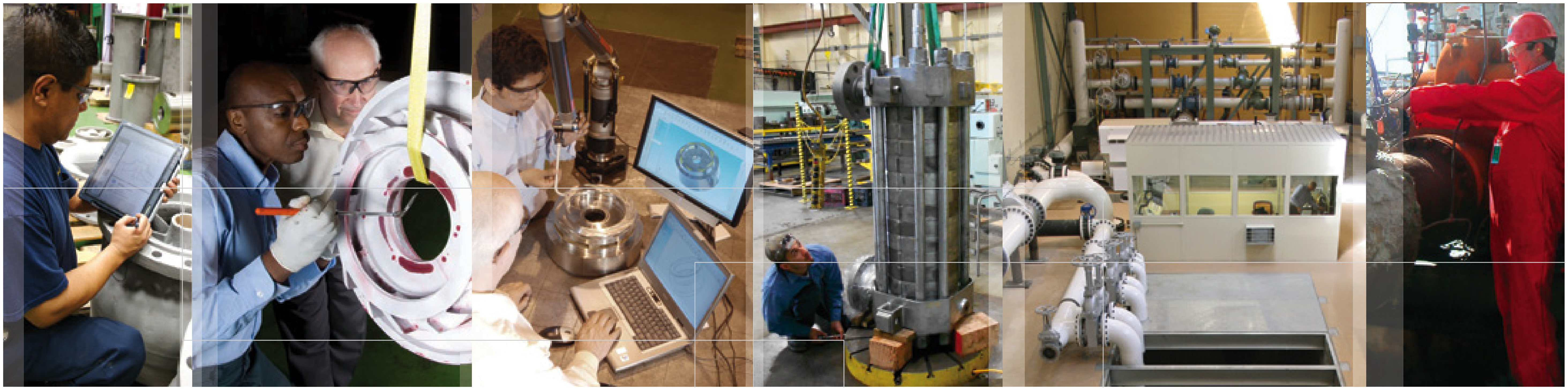

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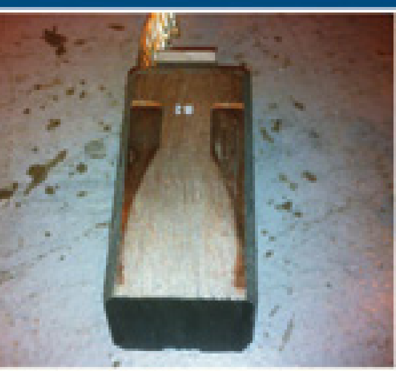

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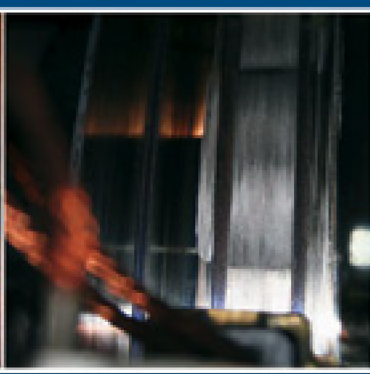

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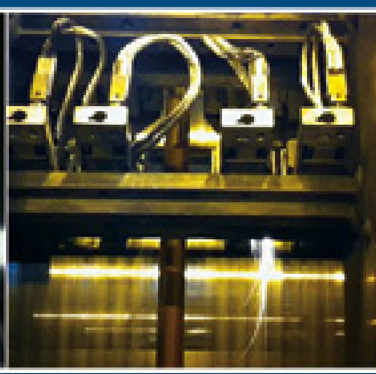

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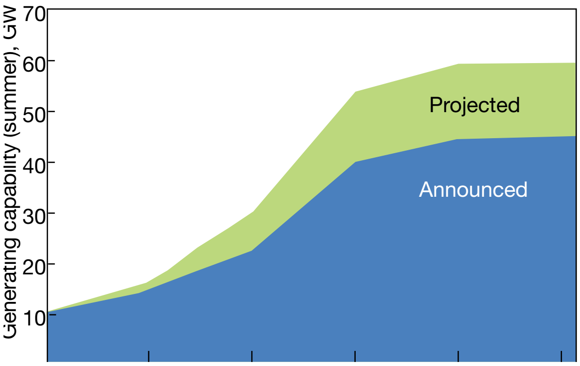
Coal retirements accelerate, gas and renewables gain market share

Despite advances in technology, wind and other renewables are still not at parity with natural gas in the US. As upcoming environmental regulations trim the nation's coal fleet, gas expands its market share as a base-load resource. Developers' current plans create a mini-boom in GT-based capacity additions, with over 60 GW expected online through 2016

By Adam Picketts, Energy Ventures Analysis Inc

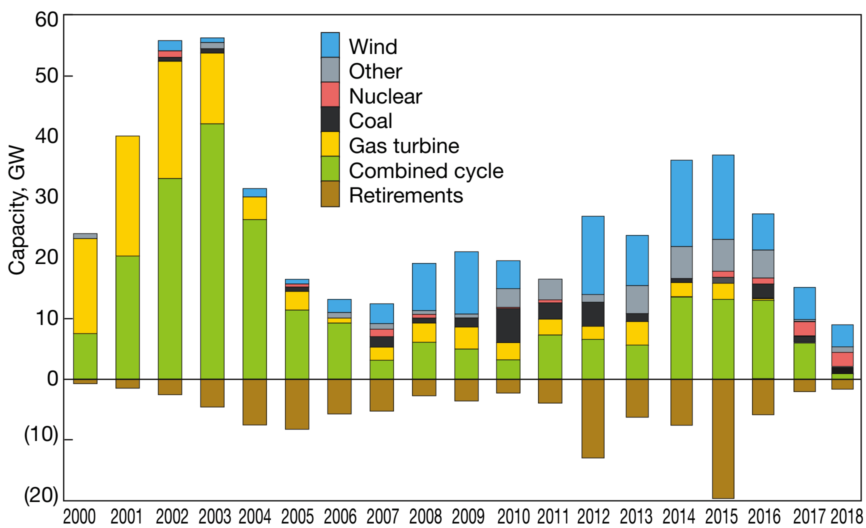
Natural-gas-fueled combined-cycle and renewables fleets will experience strong growth through 2018. Recent and impending EPA rulemakings require owners of coal-fired units to make significant capital investments on environmental controls. Faced with the decision to retrofit or retire, owners already have announced 45 GW of coal retirements from 2012 through 2018 (Fig 1). Gas will be the primary source of replacement capacity as well as the top choice for new greenfield peakers and base-load resources.



Retirements, MW

Year	Announced	Projected
2012	10,485	—
2013	4519	1310
2014	7918	6098
2015	17,185	6502
2016	4389	1035
2017	536	—
2018	—	—

1. Announced coal-plant retirements from 2012 through 2018 total 45 GW. An additional 14.9 GW will likely retire



2. Capacity additions announced for calendar years 2012-2018 total 179 GW. Natural gas will power 41% of the new capacity; wind, 36%; coal, 6%; nuclear, 4%; all other, 13%. Note that the wind market is defined by Renewable Portfolio Standards and that many announced projects have slim chances of gaining power purchase agreements and financing; also, wind capacity is the installed *nameplate* rating while other generating resources are represented by summer capacity

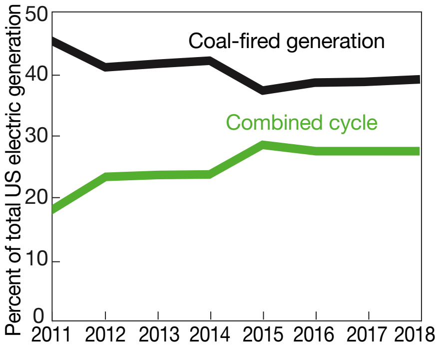
Across all fuels and technologies, capacity announcements for calendar years 2012-2018 total 179.1 GW (Fig 2). During this same period, announced retirements total 57.3 GW, leaving net US capacity additions at 121.8 GW. GT-based combined-cycle, cogeneration, and simple-cycle plants account for 41% of this total.

Although announced nameplate wind capacity is 64.7 GW, EVA estimates that only 30 GW will actually be installed (Sidebar 1). Roughly 10% of this nameplate wind capacity will be credited as firm capacity. Operators will require GT technologies to help fill the void between installed and credited wind capacity, and to balance the intermittency of renewables.

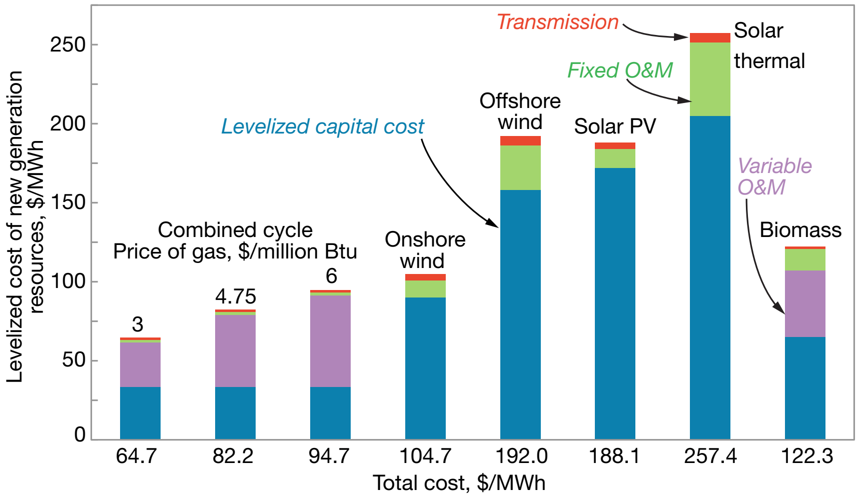
EVA forecasts gas combined-cycle generation to reach 28% of total US generation in 2018 (Fig 3). Combined cycles will remain the low-cost source for new base-load capacity for the foreseeable future as low natural gas prices and strict environmental regulations give gas an advantage. Because of lower capital costs, relatively low heat rates, and better emissions rates, combined cycles also are an attractive source of replacement base-load capacity for retired coal units.

From 2012 through 2018 over 87 GW of announced nameplate capacity additions are renewables technologies. However, the US market for renewables is fragile because developers must rely upon government incentives to compete with gas

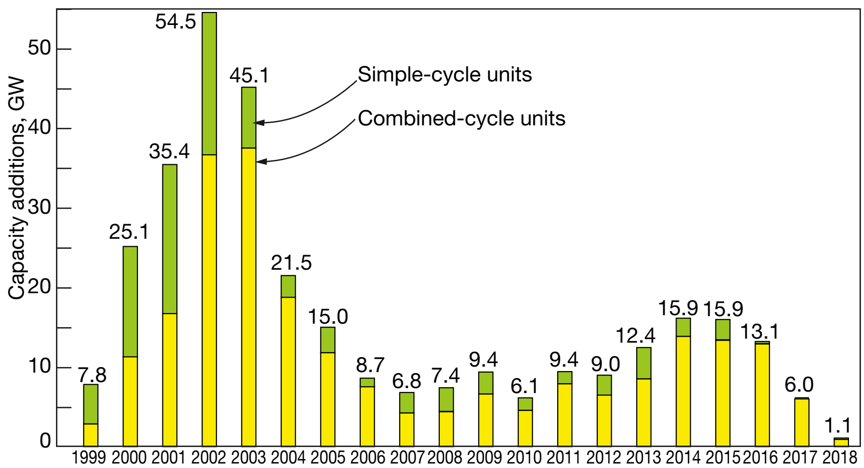
BY THE NUMBERS



3. Natural-gas combined-cycle generation is estimated to increase by 26% from 2013 levels and generate over 28% of US electricity in 2018. Coal generation will slip by 2%, leaving coal producing 39% of the nation's power, down from its forecasted 2013 market share of 42%



4. Despite technological advances, wind and other renewables are still not at parity with natural gas in the US. Low natural-gas prices allow combined cycle units to achieve a levelized cost of energy almost 40% less than that of onshore wind and 65% less than photovoltaic solar. Gas even further exceeds parity when compared to other renewables. Note that site-specific factors heavily influence the levelized cost of energy



5. Bar graph of GT-based additions suggests that a mini-boom is underway. New units are required to replace coal-fired retirements, canceled coal plants, and to balance growing intermittent renewables generation. For the period evaluated, current announcements suggest that 84% of the capacity will be combined-cycle facilities, remainder simple-cycle. Keep in mind that peaking units are ordered much closer to their operation dates than combined cycles, so expect the ratio between the two to decrease somewhat

combined cycles. EVA estimates that only 43% of the announced renewables capacity will reach commercialization.

Many renewables developers are small companies with modest tax liabilities that must rely on larger tax-equity partners to supply capital. Insufficient levels of tax-equity market capital supply will discourage development of many announced renewables projects, particularly those in the early development stage.

In addition to financing difficulties, renewables are still not at parity with gas combined cycles in the US. Low gas prices allow combined cycles to achieve a levelized cost of energy almost 60% that of onshore wind's (Fig 4). An abundant shale-gas outlook ensures renewables projects will rely heavily on government incentives to compete with gas for the foreseeable future.

New coal-plant capital costs, low natural-gas prices, and increasingly strict environmental regulations have made coal less attractive and harder to justify. Of the 11.4 GW of announced new coal capacity, EVA projects that only 6.8 GW will reach commercialization through 2018. After subtracting announced retirements, the net decrease in coal capability by 2019 would be more than 38 GW. However, EVA forecasts an extra 14.9 GW will likely retire before 2019, making the loss of solid-fuel generating capability at least 53 GW.

Mercury and Air Toxics Standards and other impending EPA rulemakings are responsible for the majority of coal retirements. MATS' strict emissions-rate limits for acid gases (HCl, HF) and heavy metals trigger substantial capital investments in existing coal units. These investments are uneconomic for many plants, especially units without scrubbers burning high-cost Appalachian coal.

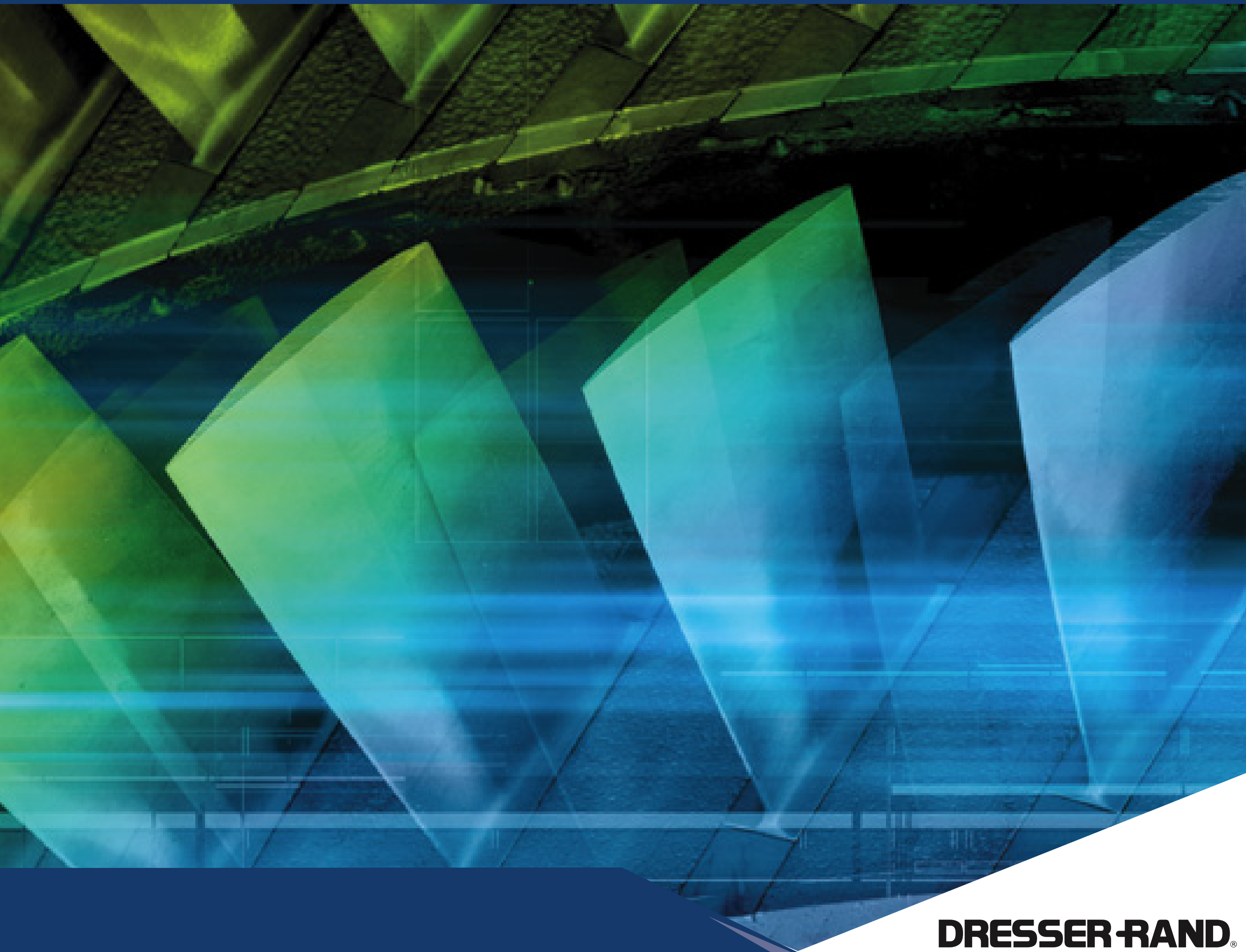
Coal-to-gas fuel switching has accelerated retirement announcements, because tighter margins and fewer operating hours reduce the opportunity for a coal unit to economically withstand any needed environmental-control retrofits. Gas combined cycles and a limited number of steam-plant conversions from coal to gas will be sources of replacement capacity.

Fig 5 presents recent history and a look ahead for GT-based capacity additions. The illustration shows the spectacular growth of this industry sector in the 2000-2005 period, when nearly 200 GW was installed. A mini-boom is currently underway and over 50 GW is expected online from 2012 through 2015.

Of the 73.4 GW announced through 2018, 84% of capacity is combined-cycle

1. Who is EVA?

Energy Ventures Analysis Inc (EVA), Arlington, Va, specializes in energy and environmental market analysis and forecasting associated with the power, natural gas, coal, oil, and emissions markets. It also assists clients in the formation, execution, negotiation, and litigation of major fuel and transportation contracts, as well as in the purchase and sale of electric power assets. Adam Picketts can be reached at picketts@evainc.com, or at 703-276-8900.



2. EVA's project tracking methodology

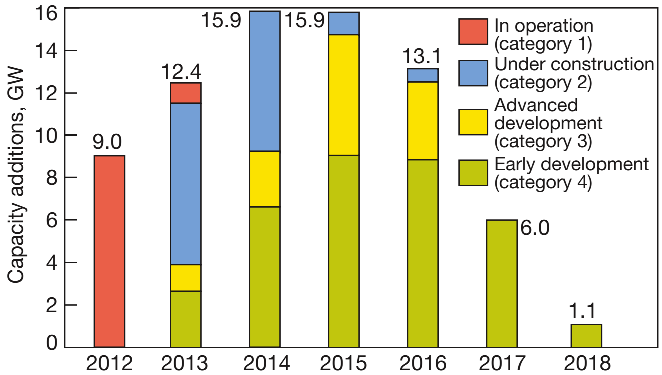
Today's mixed bag of regulation and deregulation make it far more difficult to access information on power-project development than in the regulated era. EVA has continually tracked announcements of changes to powerplant capacity since 1998. This includes new plants, retirements, uprates, and derates by fuel type in six distinct stages of development.

To track project development in a consistent and orderly fashion, EVA designates each project into one of the following six categories that rank progress towards completion: In operation (Category 1); under construction (2); advanced development stage (3); early development stage (4); unlikely (5); and withdrawn (6).

Categories 1, 2, and 6 are straightforward and easily observable. New projects often, but not always, start with public introductions by the developers themselves. When first announced, natural-gas-fired and renewable-energy projects are assigned to Category 4. New coal and nuclear projects initially are assigned to Category 5 because of the difficulties associated with building these two types of plants.

During the early-development phase, project information often is difficult to access. However, EVA retains its initial ranking for at least as long as the developer continues to pursue the project actively. Distinctive qualitative attributes relate to a particular project's progress through the development phase.

A project advances to Category 3 when it has fulfilled most, if not all, of the basic elements necessary for construction—for example, permitting, financing, and orders for major equipment. A project may be moved back a category, if it misses targeted milestones or other indicators that point to a lapse in development activity—such as no site identified. Category 6 is assigned when the developer formally withdraws the project.

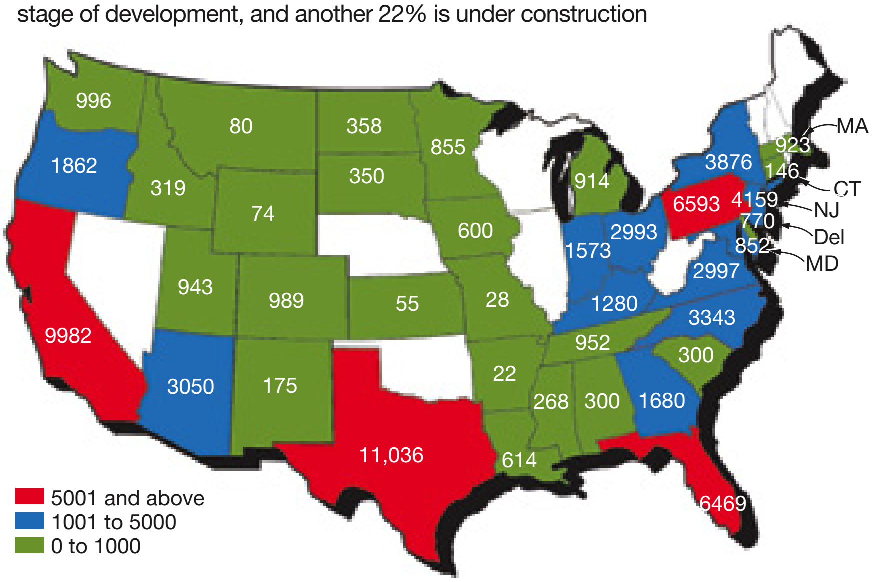


6. Gas-turbine-based capacity by stage of development profiles 73.4 GW of announced capacity for the calendar years 2012 through 2018 period. Stagnant electricity demand will likely delay some projects and force the cancellation of a few. Gas turbines are installed relatively quickly and 47% is in the early development stage, making it relatively easy to tweak startup dates. Approximately 18% of the capacity is in an advanced stage of development, and another 22% is under construction

technology, the remainder simple-cycle. This ratio will likely decrease over time because simple-cycle turbines are ordered much closer to their operating dates than combined cycles. Renewable portfolio standards will keep peaking GT capacity on the near-term radar to provide a reliable backup for wind generation and other intermittent renewables.

EVA's tracking of power-project announcements indicates that 47% of GT-based capacity from 2012-2018 is in the early development stage (Fig 6). These plants are the most vulnerable to changes in developers' plans. Another 18% of capacity is in advanced development, 22% is under construction, and 14% entered operation between January 2012 and March 2013. Over 46% of the announced new capacity is located in Texas, California, Pennsylvania, and Florida (Fig 7).

As part of its tracking program, EVA monitors each phase of every project as it winds through the development process. Each project is assigned a development category number that corresponds to its level of progress (Sidebar 2). CCJ



7. Looking at GT-based capacity additions by state from calendar years 2012 through 2018, states with the most announced new capacity are Texas (11,036 MW), California (9982), Pennsylvania (6593), and Florida (6469). Locational advantages are evident, as developers' current investment plans have carried Pennsylvania into the Top Five this year. Here, developers are taking advantage of robust shale gas supply and are forecasting delivered gas prices at a discount to Henry Hub

Axford: 25% more GT capacity will be ordered for electric generation in the US this year than in 2012

Mark Axford, the Houston-based turbine consultant considered by many to be the leading independent expert on gas-turbine markets, predicted at the Western Turbine Users Inc's (WTUI) 2013 Conference (March 10-13, San Diego) that US orders for GTs would increase by 25% this year compared to 2012. Worldwide, he expects only a 5% increase, with the Eurozone's crippling recession a major factor in the downward pressure on orders (less than 800 MW last year).

The Axford Report, as this consultant's annual presentation at WTUI has come to be known, traditionally opens the meeting on the second day of the event. It is highly regarded by conference attendees and always attracts a large audience.

Axford is bullish on the US market because of favorable gas prices underpinned by promising reserves of shale gas. The availability of energy at low cost is a primary reason for the economic rebound in the manufacturing sector—particularly in Pennsylvania, Indiana, and Ohio. He said that coal "is under pressure" when the gas price is below $3.30/million Btu.

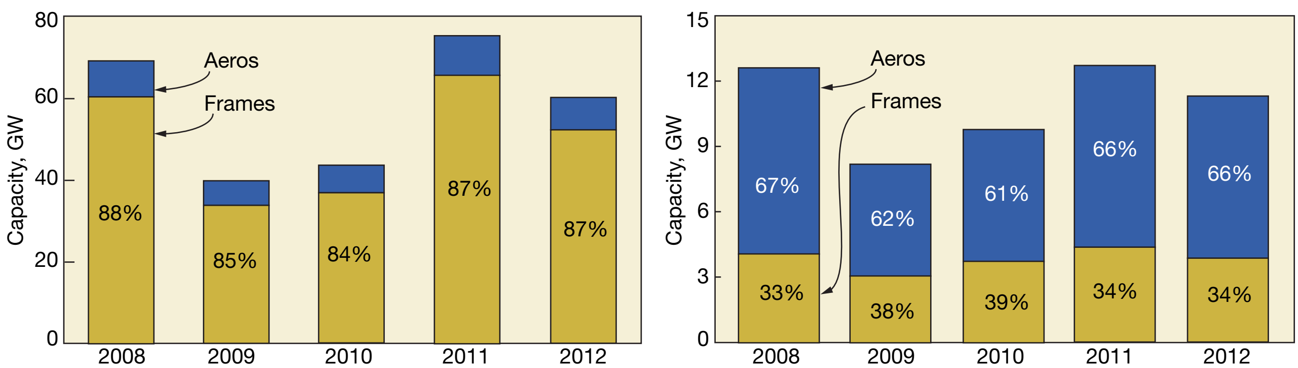
The market analyst began his well-prepared and impeccably delivered remarks almost apologetically for overestimating his *AxSpectations* of 20% US growth in 2012 compared to 2011. Actual US orders were up by about 10%. Worldwide, he had expected 5% growth and orders were down by 20%.

Geographically, 38% of the orders were from Asia, 20% from the Middle East. Regarding market share by OEM, Siemens and GE combined for 76% of the total order book in 2012; typically they have split three-quarters of annual GT sales. Mitsubishi emerged as a clear third last year, taking a 17% share.

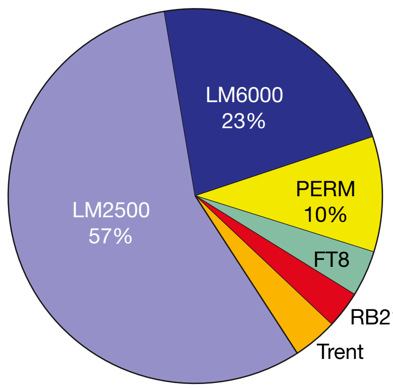
In North America, 2012 orders for aeroderivative engines totaled 1800 MW, frames 7000 MW in round numbers. GE garnered 87% of the aero market. Rolls Royce received an order for one Trent for a project in Mexico; Pratt & Whitney sold only 60 MW and those two engines went to APR as trailer-mounted gensets for international delivery. In the frame sector, however, Siemens and Mitsubishi proved tough competition for GE, which won only 33% market share based on capacity.

Worldwide, aeros captured a 13% market share of all turbines ordered in 2012. Fig 1 shows the split between aeros and frames has remained relatively constant for the last several years, with frames capturing 84% to 87% of the business. But aeros are the clear choice among users for gas turbines rated between 18 and 65 MW, which includes all the LM engines supported by the WTUI (Fig 2).

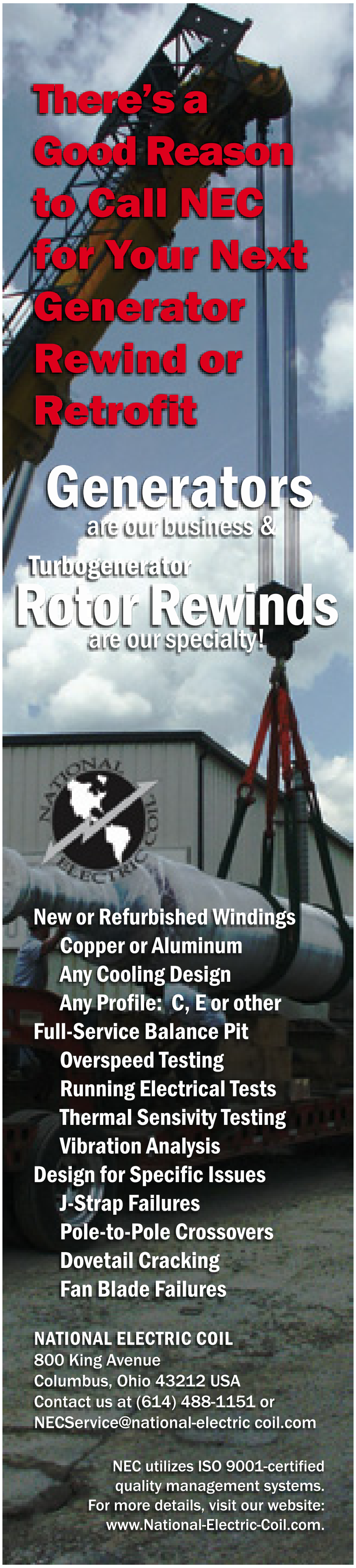
Analyzing 2012 orders placed for aeros from outside the US, Axford revealed that 57% were for LM2500s and another 23% for LM6000s. As you look at the Fig 3 pie chart it's obvious that Perm Engine Co, a virtual unknown in GT circles, was a solid third place with 10% of the business—ahead of Pratt & Whitney and Rolls Royce. The Russian company, located in the city of Perm, supplies simple-cycle and cogeneration systems for electric production, and compressor drivers for pipeline service. Sizes range

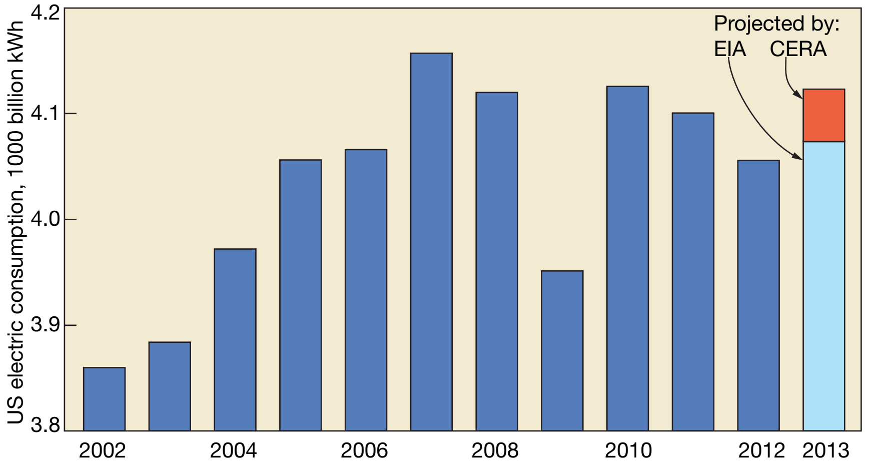


1, 2. Market share of aeros versus frames, worldwide, for all gas turbines larger than 10 MW is at left. For gas turbines rated between 18 and 65 MW, worldwide, aeros traditionally hold a 2:1 advantage in total capacity (right)

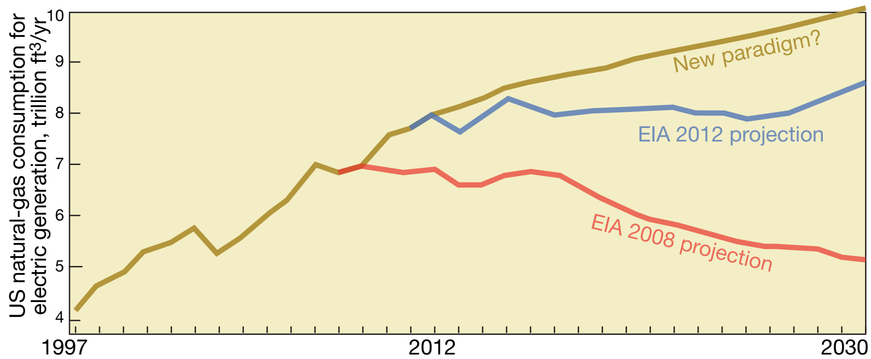


3. LM2500s and LM6000s dominated aero orders outside the US in 2012; Perm was a solid third





4. Government, private sector differ on their predictions of US electricity consumption for 2013



5. Shale-gas discoveries dramatically changed projections regarding the use of gas for producing electricity

from 2.5 to 25 MW. Its customer base is located primarily in the republics of the former Soviet Union.

Global orders for LM6000s totaled 42 engines in 2012, two fewer than in 2011. Interestingly, orders came in from 12 countries, with the US buying 10 units and the Eurozone none. Surprising, perhaps, was that orders for the LMS100 dropped dramatically from 16 in 2011 to two in 2012. To date, a total of 56 simple-cycle units have been ordered, 38 for the US. The consultant believes annual sales will rebound to 10 units this year.

Axford began wrapping up the presentation with a couple of charts that supported his prediction for a significant increase in US gas-turbine orders this year. Fig 4 shows the expected growth in US electricity consumption for 2013 as reported by DOE's Energy Information Administration and by IHS CERA (many in the industry will remember this well-respected group by its former name, Cambridge Energy Research Associates).

EIA predicts a 0.5% increase, CERA, which has its fingers on the pulse of the US economy, predicts more than three times that (1.6%). Back-of-the-envelope calculations by Axford offered valuable perspective on the difference between the numbers. He said the difference (red portion of the bar) translates to the annual generation by 1140 LM6000s operating at base load.

The impact of shale-gas discoveries in the US is shown in Fig 5. Axford believes the price of natural gas could remain low and stable for the next several years at least. Coal, which produces 42% of the nation's electricity today, is expected to generate 37% at the end of 2017 according to government data. Gas, by contrast, which stood at 25% as 2013 dawned, is expected to grow to 30% within five years.

Axford closed with these thoughts, among others:

- Europe's recession continues, but the order rate for GTs should improve in 2013. One reason is that Germany is relearning its need for fossil generation.
- Order rate for gas turbines in Asia could leap upward if China's "shale gale" materializes.
- Electricity rationing continues in Japan, which last year produced 45% of its electricity from LNG. In the aftermath of Fukushima, four-dozen nuclear units still wait for approval to restart. CCJ

Pedigree and performance: the 'Test of Champions'

By Salvatore A DellaVilla Jr, CEO, Strategic Power Systems Inc

On June 9, 1973, history was made in Elmont, NY, the town just outside of New York City famous for hosting the Belmont Stakes. That day, a crowd of 67,605 racing enthusiasts, plus another 10.9 million watching on TV, waited to see if a three-year-old thoroughbred named *Secretariat,* chestnut brown with a strong pedigree, would take the Triple Crown—a coronation that had not occurred since 1948.

Secretariat, would not disappoint in the "Test of Champions."

The Belmont Stakes, the longest of the three Triple Crown races at 1½ miles, is a test of agility, speed, power, and endurance. The opportunity to challenge for the Triple Crown begins with wins at the Kentucky Derby (1¼ miles) and the Preakness Stakes (1³⁄₁₆ miles). Within a two-week period, *Secretariat* had won both the Derby and Preakness by 2½ lengths over a formidable contender named *Sham,* which also came from a strong pedigree. He might have been a Triple Crown contender at a different moment in time.

Three weeks after the Preakness, only *Sham* and three other horses were in the Belmont starting gate with *Secretariat,* hoping to spoil his chance for a Triple Crown and continue the 25-yr drought.

It was not to be.

1^{hd}, 1^{hd}, 1^{7}, 1^{20}, 1^{28}, 1^{31}. After a fast start, *Secretariat* was leading *Sham* by a head at the first quarter pole. He maintained that lead through the half and then began pulling away. "Big Red" blew by the mile pole seven lengths ahead of *Sham* and the challenger faded. He would finish last.

Secretariat extended his lead to 20 lengths over the next quarter of a mile, increased it to 28 lengths down the stretch, and finished 31 lengths ahead of *Twice a Prince* in record time. The 2:24 *Secretariat* logged that day still stands as a world record for the mile and a half on a dirt track.

Many people who saw that race still feel the excitement in the voice of Belmont Announcer Chick Anderson, "*Secretariat* is alone: He is moving like a tremendous machine!"

Another tremendous machine

The energy industry continues to advance, in large part, because of tremendous *machines,* gas turbines (GTs) in particular, whose pedigree and performance improve to meet the demands of an ever-changing and challenging market. Today's drivers influencing operations and maintenance, as well as new product design, include the following:

- Fast start-up times.
- Impact of cyclic duty on parts life and maintenance schedules.
- Load-following and –shedding to the lower and lower outputs required to accommodate swings associated with intermittent renewables, all while continuing to meet rigorous emissions standards.
- The value of reserve or "sitting" capacity.

For owners and OEMs alike, success depends on the flexibility and responsiveness of their machines to start and reach rated power in less time than the competition, and to do so more efficiently and more reliably over time and within operating constraints imposed by regulations. In effect, to have the opportunity to be "in the money" at all times. This, too, is a "Test of Champions."

Table 1 charts the evolution of the "heavy duty" (more commonly referred to as "frame") GTs by class, or pedigree, from the legacy engines to "J" class. For these machines, product evolution is characterized by output, thermal efficiency, firing temperature, compressor ratio, and use of the latest technologies available—such as enhanced airfoil cooling, ultra-low-emissions combustion, and advanced metallurgy.

For aeroderivative product offerings, the pedigree has evolved from an aviation heritage, drivers of advancements in technology, addressing similar design issues and constraints as these products are placed in land-based applications.

OEM product offerings fit into the pedigree classes or "peer groups" shown in Table 2. Engines in each class compete based on installed cost, O&M cost, and performance (both thermal and operational).

To compare operational performance by pedigree, data extracted from the Operational Reliability Analysis Program (ORAP®) are presented in Table 3. Reliability/availability/maintainability (RAM) are shown for the aeroderivative, "E," and "F" classes of engines characterized in the first two tables.

The metrics presented were developed from data gathered across the

Table 1: General characteristics of frame gas turbines by class

Market segment	Base rating, MW	Efficiency, %	Firing temperature	Pressure ratio	State-of-the-art technology	Year introduced
Legacy engines	<100 (50 Hz) <70 (60 Hz)	SC: <34 CC: <55	<1093C <2000F	<12	None	<1985
"E" class	>100 (50 Hz) >70 (60 Hz)	SC: <34 CC: <55	>1093C >2000F	<15	Air-cooled turbine blades	<1995
"F" class	>200 (50 Hz) >150 (60 Hz)	SC: >34 CC: >55	>1260C >2300F	>15	Aeroderivative compressor design Dry low-emissions combustor DS or single-crystal turbine blades Sequential combustion	>1995
"G," "H" classes	>300 (50 Hz) >200 (60 Hz)	SC: >37 CC: >58	>1370C >2500F	>18	Advanced HGP cooling Active clearance control	>2005
"J" class	>450 (50 Hz) >300 (60 Hz)	SC: >39 CC: >60	>1600C >2900F	>25	Advanced combustor cooling Advanced thermal barrier coating	>2009

Source: Strategic Power Systems Inc and Electric Power Research Institute
Notes: (1) The criteria described in the table are determining factors in the classification of individual designs and are listed in priority order from left to right. (2) State-of-the-art technology refers only to the technology introduced in a design at the date of introduction; it does not refer to retrofits made to enhance existing technology. (3) Efficiency is stated for both simple-cycle (SC) and combined-cycle (CC) applications using the lower heating value of fuel. (4) Base rating represents the simple-cycle equipment only.

Table 2: Gas-turbine models arranged by peer group and OEM

Frame gas turbines					Aeroderivative gas turbines	
Legacy engines	"E" class	"F" class	"G," "H" classes	"J" class	<40 MW	>40 MW
Alstom	**Alstom**	**Alstom**	**GE**	**Mitsubishi**	**GE**	**GE**
GT8/8B	GT8C	GT24	MS9001H	M701J	LM1600	LM5000
GT9	GT11N/N1	GT26	MS7001H		LM2500	LM6000
	GT11NM/11N1M					
GE	GT11N2	**GE**	**Siemens**		**Rolls Royce**	**Rolls Royce**
MS5001	GT13E/E1	MS6001F/FA	SGT6-6000G		Avon	Trent
MS5002	GT13E2	MS7001F/FA			RB211	
MS6001B		MS9001F/FA	**Mitsubishi**			
MS7001A-C	**GE**	MS7001FB	M501G			**Siemens**
MS9001B	MS7001E/EA	MS9001FB	M701G		**Pratt & Whitney**	GTX100
	MS9001E				FT4	
Siemens		**Siemens**			FT8	
W251	**Siemens**	V84.3				
W501A/B	W501D	SGT-1000F				
SGT-700	SGT5-2000E	SGT5-4000F				
SGT-800	SGT6-2000E	SGT6-4000F				
V64.3	SGT6-3000E	SGT6-5000F				
	W701D					
		Mitsubishi				
	Mitsubishi	M501F				
	M501D	M701F				
	M701D					

globe from plants operating in various duty cycles that participated in the ORAP program in 2012, as well as during 2007-2011. The information is presented by peer group and by duty cycle. The latter is indicative of the mission profile that these units must meet and are represented by the following parameters:

- Annual service hours.
- Annual starts.
- Service hours per start.
- Service factor.
- Capacity factor.
- Availability.
- Reliability.

Here's an assessment by SPS engineers of the data included in Table 3:

Peaking units. Units that have historically operated in a peaking duty cycle offer some interesting comparisons when comparing 2012 performance to average annual data for the prior five-year period (2007-2011). They are:

- In 2012, peaking units across all classes (aeroderivative, "E," and "F") had significantly more annual service hours than they did in 2007-2011. Specifically, both aero and E peakers ran about 40% more service hours in 2012 than in the previous five-year period, "F" class units about 34% more.
- The mission profile for peakers across all peer groups in 2012 compared to 2007-2011 reflects more starts, more service hours per start, and higher capacity factors. Yet, as expected, these units were in reserve standby for most of last year: 7358 hours for aeros, 7840 hours for "E" class units, 7236 for "F."
- Availability and reliability factors are very consistent period over period. For both 2012 and 2007-2011, planned and unplanned maintenance were the primary drivers of unavailability for all classes. Last year they contributed 315 downtime hours for aeros, 307 for "E" class units, and 394 downtime hours for "F" class.

Cycling units also provide some noteworthy comparisons for the two time periods:

- Both classes of frames ran more hours in 2012 than they did in the earlier period: "E" engines about 45% more service hours, "F" class about 21% more. Aeros operated consistently. Service hours in 2012 decreased by only about 1% compared to 2007-2011.
- "E" and "F" engines operated substantially more service hours per start in 2012—73% and 52%, respectively—over 2007-2011 levels. This reflects a significant increase in unit demand. Aeros also ran more service hours per start in 2012, but had the smallest increase of the peer groups (about 20%).
- All classes experienced fewer annual starts in 2012—about 17% less for aeros and about 20% less for "E" and "F" class units. Also important to note is that the demand profile for all classes of cycling units does not show 200 annual starts. Service factors and capacity factors for cycling units increased period over period, indicating a change in demand or mission profile.
- In 2012, only aeros improved in both availability and reliability, compared to 2007-2011. They had about 61 fewer forced-outage hours and seven more days of availability in 2012 when compared with the previous period.

For "E" and "F" class cycling units, as for the peakers in those peer groups, planned and unplanned maintenance was the primary driver of unavailability. In 2012, maintenance accounted for 499 downtime hours among the "E" class machines and 596 downtime hours for "F" class units. The impact of cycling duty on maintenance is evident in these results. The aeros were only charged with 272 hours of downtime related to planned and unplanned maintenance in 2012.

Base-load units produced these results:

- In 2012, each peer group operated fewer service hours than it did in 2007-2011. Aero and "E" units ran 7% and 8% fewer hours, respectively; "F" engines were off 2%.
- Service hours per start for both aeros and "F" class units were relatively consistent period over period. By contrast, the service hours per start for "E" machines in 2012 decreased by a whopping 26% from 2007-2011.

In 2012, aeros had 10 fewer

Table 3: Key performance indicators developed from ORAP® RAM metrics

Parameter	2012 Aero	2012 "E" class	2012 "F" class	2007-2011 Aero	2007-2011 "E" class	2007-2011 "F" class
Peaking units:						
Annual service hours	851	527	990	608	375	737
Annual starts	119	71	92	111	62	78
Service hours/start	7.1	7.4	10.8	5.5	6.1	9.5
Service factor, %	9.7	6.0	11.3	6.9	4.3	8.4
Capacity factor, %	8.5	4.9	9.9	5.7	2.9	6.7
Availability, %	93.7	95.5	93.9	93.7	95.1	94.4
Reliability, %	97.3	99.0	98.4	97.4	99.0	99.1
Cycling units:						
Annual service hours	2253	3419	4685	2276	2355	3877
Annual starts	143	121	112	172	145	141
Service hours/start	15.8	28.2	42.0	13.2	16.3	27.6
Service factor, %	25.7	39.0	53.5	26.0	26.9	44.3
Capacity factor, %	20.6	30.4	46.3	19.7	21.4	37.1
Availability, %	94.0	93.3	90.9	92.1	93.8	91.1
Reliability, %	97.1	99.0	97.7	96.4	98.7	97.7
Base-load units:						
Annual service hours	5779	6284	5900	6233	6860	6027
Annual starts	79	40	59	89	32	62
Service hours/start	73.2	157.6	99.2	69.9	213.8	97.0
Service factor, %	66.0	71.7	67.3	71.2	78.3	68.8
Capacity factor, %	53.6	64.5	55.1	56.2	69.2	56.5
Availability, %	91.4	92.5	89.4	92.2	93.0	92.5
Reliability, %	95.9	98.2	97.9	97.0	98.1	98.0

starts than they averaged in the previous period, while "E" engines had eight more starts and "F" engines had three fewer starts. Capacity and service factors were relatively high and consistent period over period.

- Availability decreased slightly for each unit class in 2012. For the frame engines, the decrease was caused by an increase in the amount of planned and unplanned maintenance, period over period—53 hours for "E" machines and 263 hours for "F" units. For aeros, availability dropped because of an increase in forced-outage time of about four days.

Regional impacts. To better understand how operating paradigms vary with region, SPS engineers compared capacity factor and reserve standby factor data for aero and "E" and "F" class gas turbines in the Northeast, South, Midwest, and West (Table 4).

- Aeros and "E" class frames in the West and Northeast had higher capacity factors and lower reserve standby factors than like engines located in the Midwest and South. Capacity factors for aeros increased, and reserve standby factors decreased, from the 2007 to 2011 period to 2012 in the Midwest and Northeast. For "E" machines, capacity factors increased in all regions between 2007 to 2011 and 2012 except the West; the converse was true for the reserve standby factors.
- Capacity factors for "F" class units nationwide increased between the 2007-2011 period and 2012; by contrast, reserve standby factors decreased.

While past performance may not predict future performance, it does matter and should be understood because it sets market expectations and establishes the baseline for product improvement.

Past performance can be something to admire. By the end of *Secretariat's* short two-year career, he had run in 21 races, compiling 16 wins, three seconds, and one third-place finish. He was in the money 95% of the time, winning more than $1.3 million and ringing up an additional $6 million through syndication as a stallion—a world-record amount at that time.

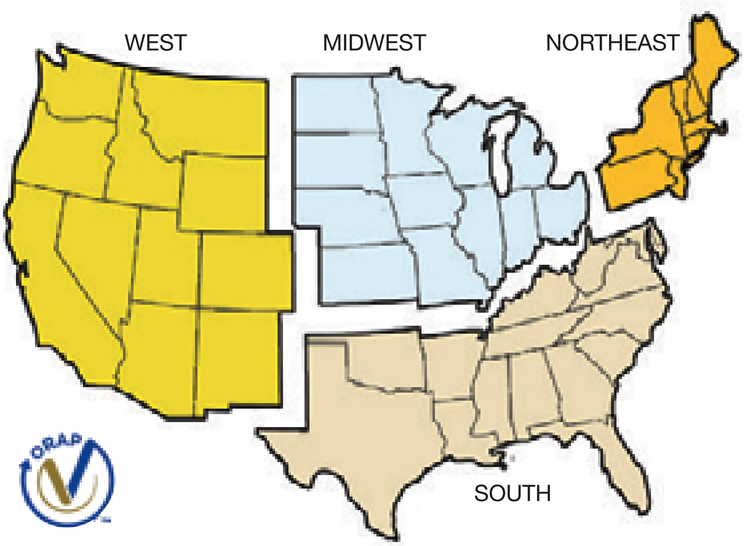
Pete Axthelm of Newsweek magazine wrote: "If there is urgency in every 26-ft stride that *Secretariat* takes, there is also a rich, meandering history behind him; it is a tale of hope and vision, painstaking work, and superb performance under pressure. . . ."

Sounds a lot like the gas-turbine industry. CCJ

Table 4: Comparing peer-group capacity (CF) and reserve standby (RSF) factors regionally

Parameter	2012 Aero	2012 "E" class	2012 "F" class	2007-2011 Aero	2007-2011 "E" class	2007-2011 "F" class
West						
CF, %	22.8	34.6	60.7	29.5	38.1	47.9
RSF, %	61.3	54.2	21.1	49.8	46.0	33.7
Midwest:						
CF, %	14.5	8.9	23.7	6.4	3.8	14.2
RSF, %	70.3	86.8	65.4	83.8	88.2	76.6
Northeast:						
CF, %	20.6	48.9	67.6	15.1	37.6	46.7
RSF, %	69.3	36.7	14.4	70.6	47.2	40.9
South:						
CF, %	13.0	14.3	44.5	15.5	12.3	32.8
RSF,	77.1	78.2	43.3	72.5	81.2	54.2

Note: West includes Alaska and Hawaii



Young & Franklin Inc.

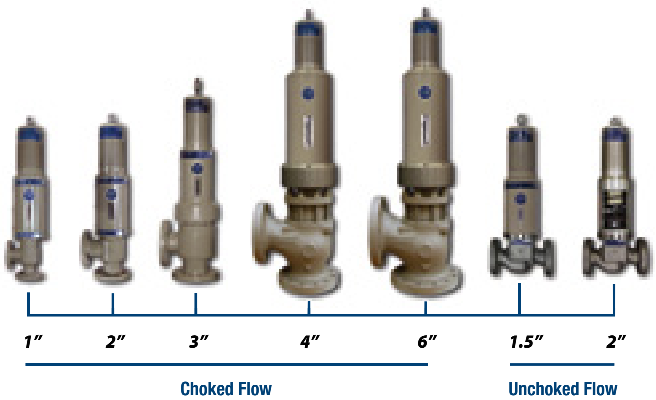
Founded in 1918 and headquartered in Liverpool, New York USA, Young & Franklin Inc. (Y&F) designs, manufactures and services turbine controls for the energy and oil & gas markets. Original equipment manufacturers and asset owners from across the globe look to Young & Franklin for fluid control solutions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

Industrial turbines require precise control of the combustion process to drive efficiency, reduce emissions and increase availability. Young & Franklin air and gas control assemblies provide that accuracy with a complete range of electromechanically or hydraulically actuated products. From choked and unchoked valves to double block and bleed isolation valves to inlet guide vane actuators, Y&F offers a vast range of solutions for the most demanding industrial turbine applications.

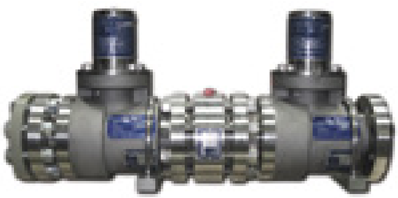
Fuel Control Applications

Young & Franklin delivers proven electromechanical actuation (EMA) for electric fail-safe and non-fail-safe fuel control applications as well as traditional hydraulic solutions. Our patented compact, linear electromechanical actuators are the basis for a complete ship-set of electric Combustion Turbine controls.



3010 Series EMA Gas Fuel Control Assemblies ~
A family of electrically actuated single seat precision gas fuel control valves available in a variety of sizes of choked and unchoked flow configurations. Driven by the Y&F 1100 Series Digital Actuator Controller, the 3010 Series features balanced valve design, fail-safe spring closure for added safety and reliability, and feedback obtained through a resolver or optional LVDT.

Isolation Valve



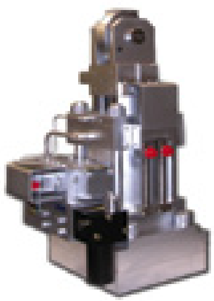
Isolation Valve in Double Block & Bleed Format

9200 Series Isolation Valves ~ A single stage, solenoid operated, pilot controlled, drop-in replacement isolation valve. This high temperature shutoff valve closes in less than 100ms and has a Cv of 72. A double block and bleed configuration is also available.

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).

IGV Actuation Technologies

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.

Our deep technical competency in hydraulically actuated controls has enabled the company to develop a line of electromechanically actuated (EMA) valves and guide vane actuators. By eliminating the use of turbine lubrication oil, our EMA solutions upgrade the precision, control, performance and reliability of industrial turbines while reducing emissions, improving safety and resolving varnish issues. Y&F possesses impressive in-house design and manufacturing capabilities including an experienced dedicated engineering staff and wide range of advanced CNC machine work centers. We have achieved ISO 9001:2008 certification due to our strict adherence to quality management standards and a culture based on continuous improvement. Global field support is available 24/ 7 through our network of Young & Franklin Authorized Repair & Overhaul partners.

To learn more about Young & Franklin, please call 315.457.3110 to speak with an applications specialist or visit our web site at www.yf.com

Best Practices Awards

Recipients of the 2013 Best Practices Awards were honored during a special session and luncheon at CTOTF's™ 38th Annual Spring Conference and Trade Show, held April 7-11 at the Marriott Resort and Spa in Myrtle Beach, SC.

One of the biggest challenges facing owners and operators of generating assets in deregulated markets is the need to continually improve the performance of their facilities—to increase revenues and decrease expenses. One component of this goal of "continual improvement" is best practices. These are the methods and procedures plants rely on to assure top performance on a predictable and repeatable basis.

The Best Practices Awards program, launched in late 2004 by the **CCJ,** has as its primary objective recognition of the valuable contributions made by plant staffs—and headquarters engineering and asset-management personnel as well—to improve the safety and performance of generating facilities powered by gas turbines. There are two levels of awards to recognize the achievements at individual plants: Best Practices and The Best of the Best (BOB).

The top awards, as voted by a team of 10 judges selected from the Leadership Committee of the Combustion Turbine Operations Technical Forum™, went to six plants (italics in the summary listing below) in four of the nine awards categories for 2013. The Best Practices program was modified this year by a joint CTOTF/CCJ working committee to encourage entries pertinent to industry-wide initiatives—such as fast starts, performance improvements, workforce development, and NERC CIP V.4 compliance.

Another change was to recognize Best of the Best recipients by rank across all entries rather than by category, as had been the practice. The result: No BOBs were awarded for plant safety procedures, outage management, O&M mechanical, NERC CIP V.4, and natural-disaster preparedness and recovery, although several plants received Best Practices plaques in all but one of those categories. The scorecard used by the judges (p 91) considers business value, degree of complexity, staff involvement, external coordination, and duration of value.

These are the plants recognized for their best practices in 2013:

- **Fast starts:** *Newington Energy Facility, Encogen Generating Station,* Holden Power Plant, and Osprey Energy Center.
- **Natural-disaster preparedness and recovery:** Bridgeport Energy, Dogwood Energy Facility, and Tenaska Kiamichi Generating Station.
- **O&M electrical—including generators and transformers:** *Newington Energy Facility,* Lea Power Partners LLC, and John Sevier Combined Cycle Plant.
- **O&M mechanical—including major and BOP equipment:** Newington Energy Facility, Lea Power Partners LLC, Dogwood Energy Facility, Johnson County Generation Facility, TermoemCali, Walter M Higgins Generating Station, Tenaska Lindsay Hill Generating Station, and John Sevier Combined Cycle Plant.
- **Outage management:** MEAG Wansley Unit 9, New Harquahala Generating Co LLC, and McClain Power Plant.
- **Performance improvements:** *Effingham County Power, Johnson County Generating Facility, Klamath Cogeneration Plant,* Central de Ciclo Combinado Saltillo, Athens Generating Plant, Faribault Energy Park, and John Sevier Combined Cycle Plant.
- Plant safety procedures: Effingham County Power, Sabine Cogen LP, Granite Ridge Energy, and Rokeby Generating Station.
- Workforce development: *Effingham County Power, NV Energy Inc,* Crockett Cogeneration LLC, and Dogwood Energy Facility.

NAES Corp was the most successful operating company this year, as it was in 2011 and 2012, with seven plants the company manages capturing 10 awards—including one BOB (p 45). Consolidated Asset Management Services (CAMS) was the second-most recognized operator with four plants receiving eight awards—including two Best of the Bests (p 41). TVA and Essential Power LLC led the owner/operators submitting entries, each earning three awards. Tenaska Inc and NV Energy were the only other recipients of multiple awards, with two each.

Sponsors of the 2013 Best Practices Awards program were Dresser-Rand Turbine Technology Solutions, Emerson Process Management Power & Water Solutions, Goose Creek Systems Inc, Pratt & Whitney Power Systems, Sulzer Turbo Services, and Wood Group GTS.

Plants participating in the 2013 Best Practices Awards program

Newington

Continuous-blowdown block valve reduces startup time, plus

Best of the Best Award

Challenge. At Essential Power LLC's Newington Energy Facility, the high-pressure (HP) steam-drum continuous blowdown system was designed to cascade flow to the intermediate-pressure (IP) steam drum. The facility originally was equipped with an automatic globe-style control valve for HP blowdown.

While the valve worked well for *controlling* flow, it did not have the degree of leak-tightness required for *stopping* flow from the drum during typical overnight shutdowns. Blowdown service is a challenging application because the valve can experience flashing with a differential pressure of up to 1550 psi. Note that the plant, which began commercial operation in 2002, was designed to operate base load and did so until 2008. Since then the facility has cycled, averaging about 230 starts annually.

After several repairs to the valve trim, plant personnel decided to abandon the original globe valve and they worked closely with a manufacturer to identify a replacement capable of providing the desired flow control while also assuring tight shutoff for overnight periods. The replacement selected was an angle valve with both improved trim suitable for flashing service and Class V shutoff. The angle valves were installed on the HP blowdown lines for both HRSGs in 2010. They worked well for about six months. Then the valve trim again required repair because of excessive leakage from the HP to IP drums during overnight shutdowns.

The excessive leakage caused several problems, including these:

- Loss of water level and pressure decay in the HP drums overnight.
- Increase in water level and high pressure in the IP drums, requiring operators to blow down those drums frequently.
- Depending on the duration of the overnight shutdown period, a so-called "450 hold"—identified as a 30-min HRSG OEM-required, HP-drum heat soak at 450 psig—could be required during boiler restart before the gas turbine was ramped up to operating conditions.
- Addition of cold feedwater to the HP drum to bring its level back within the operating range prior to GT startup.
- Increased consumption of demineralized water, requiring more frequent regenerations of demin trains.

Eric Pigman, Ed Sundheim, and Chad Harrison (l to r)

Solution. Research by plant personnel indicated that manual isolation valves were not a viable solution for a plant cycling daily. They worked with the supplier of the replacement angle control valve to investigate if other trim materials or valve types could be used to reduce or eliminate the blowdown leakage. An automatic replacement blowdown-valve solution could not be identified.

Thus plant personnel decided to install an automatic full-port ball valve upstream from the existing automatic control valve to eliminate the risk of flashing. A 2-in., 2250-psig, air-actuated and metal-seated bidirectional ball valve from ValvTechnologies Inc was selected for this service (Fig 1). The ball valve is equipped with a Morin fail-closed, spring-return actuator and position limit switches.

The new valves were installed near the HP drum on each HRSG during a recent outage and have been in service for several months. The open/closed block valves are controlled automatically from the DCS. Limit-switch feedback to the control room provides assurance of proper opening and closing of the block valve.

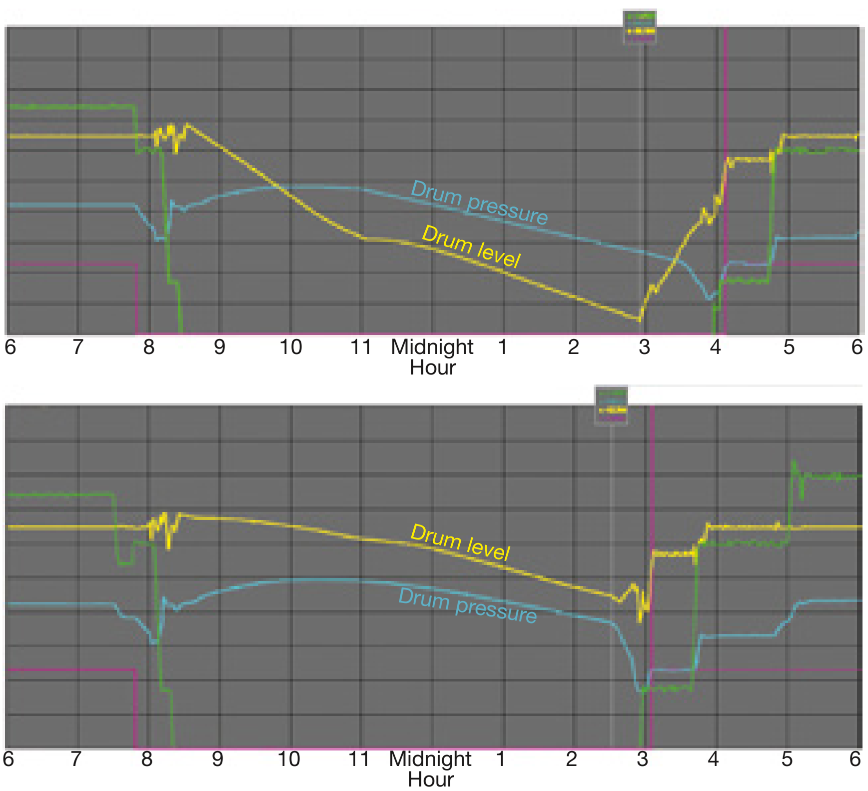
Results. The new block valves showed immediate results. During the first overnight shutdown period following commissioning of the valves, the decrease in HP drum level was significantly less and did not require addition of water to satisfy the GT start permissive the following morning. Additionally, operators did not have to blow down the IP drum during the overnight period and a "450 hold" was not required during the morning start.

1. New air-operated block valve was installed upstream of the existing automatic blowdown valve, inside the ASME boundary for boiler external piping

Additional longer-term benefits include these:

- Reduced both makeup (city water) requirements and the consumption of demin regeneration chemicals (sulfuric acid and caustic soda).
- Improved drum chemistry, because large swings in drum level have been eliminated. Consumption of chemicals for boiler water treatment also has been reduced.
- HP-drum thermal stresses have been reduced by eliminating the addition of large quantities of cold water after an overnight shutdown.
- Decreased start-up times by avoiding costly "450 holds."
- Avoided maintenance costs that would have occurred from using the blowdown valve to shut off flow had the block valve not been installed.

Project participants:
Chad Harrison, maintenance manager
Ted Karabinas, maintenance technician
Scott Courtois, I&C technician



2, 3. Before block valve installation (top): Drum level at start, -0.2 in.; at end, -39 in. Drum pressure at start, 1244 psig; at end, 810 psig. After block valve installation (bottom): Drum level at start, -1.4 in.; at end, -12.7 in. Drum pressure at start, 1252 psig; at end, 1101 psig

Breaker retrofit protects transformer

Best of the Best Award

Challenge. Newington Energy Facility was designed having the steam turbine/generator (ST) directly connected to the 18/345-kV step up (GSU) transformer with no low-side generator breaker. This was not problematic during the first six years of commercial service when the site averaged only 12 combined-cycle starts annually.

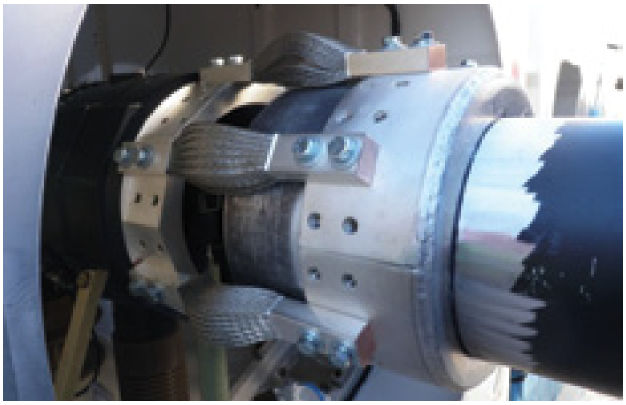
However, reliability problems were encountered in cycling operation (today the plant averages 230 starts annually) and four forced outages were experienced within two years. Investigation identified several related risks associated with near-daily synchronizing across the 345-kV breaker, including the following:

- The breaker was designed as a transmission breaker and the OEM said there could be reduced overhaul intervals and potential reliability issues if used in a daily synchronizing application.
- In the event of a GSU fault, the inability to isolate the generator from the transformer would allow the generator to continue to feed the fault as it spun down and the field decayed, increasing the damage caused by the original fault.
- With the current design, a stuck generator-breaker fault would cause the site's transmission interconnect to trip, initiating a black-plant, full-load rejection and trip of the gas turbines. This scenario would leave all three turbines coasting down with dc oil pumps operating and increasing the risk of collateral damage plant wide.
- With the transformer de-energized each night, it was subject to hundreds of thermal cycles annually. This was of particular concern during winter months when ambient temperatures onsite frequently can reach the single digits.

Solution. After extended study and analysis, the plant elected to install a purpose-built 18-kV generator breaker in the bus between the generator and the GSU on a fast-track schedule. The project was complex and required an engineering firm with mechanical, electrical, civil, and structural capabilities. The initial design effort required a detailed accounting of all control and protection functions, some of which would require relocation while oth-

4. Bus duct (left) is cut to allow breaker installation. Blast wall behind transformer is at left

5. Breaker is installed on elevated platform with sufficient area for maintenance (below)



6. Braids connecting bus duct to breaker are installed

7. Installation complete. Note location of breaker control cabinet at ground level for easy accessibility by operators making rounds (right)

ers would be duplicated on the new breaker.

A new breaker failure scheme also was designed and incorporated into the existing protection functions. Plant engineers worked with the generator OEM to modify and re-commission the synchronization-program logic in the generator controls. The new breaker also required incorporation of alarm and status information into the site DCS and historian, as well as into two different offsite Scada systems.

The project involved revision or creation of over 100 detailed drawings. Multiple iterations of site and engineering reviews were conducted to ensure interconnection accuracy. An onsite as-built termination audit was conducted to ensure the site's drawings accurately reflected the as-installed condition before design work began.

Plant personnel took a very conservative and collaborative approach to commissioning, assembling a team consisting of the design engineer, the breaker OEM, the site's relay testing firm, and a ST controls engineer experienced in new-unit commissioning. Five days of extensive testing concluded by closing the new breaker with a simulated turbine speed, energizing the 18-kV bus up to the open generator links. All control, protection, status, and alarm functions on the new breaker and on the original breaker were demonstrated during the testing.

Site staff also was able to incorporate several O&M-friendly features that normally might not be included during new plant construction. Steel work includes a 360-deg, 100% deck to allow access to all areas of the breaker, including the underside linkages, without the need for staging. A roof was incorporated to mitigate weather impacts.

The control panel was relocated to ground level to reduce the vertical ladder exposure to employees. Long-lasting LED lighting was incorporated to reduce re-lamping needs. Lastly, a detailed alarm annunciator at the breaker's local control cabinet was specified to allow the site to determine the exact cause of an alarm without resorting to detailed trouble shooting of the typical "daisy chained" generic trouble alarm. These improvements will contribute to the long-term success of the project.

Results. The initial engineering purchase order was issued Mar 28, 2012 and the breaker order placed in early May. The generator breaker was installed during a 14-day planned outage in November 2012 (Figs 4-7). Installation went as planned with no significant issues. When the plant was restarted, the new generator breaker closed without issue on the first pass of the synchroscope. The breaker has effectively reduced or eliminated the risks identified when the site entered cycling service. The project is expected to improve long-term reliability and maintainability of the plant, whether it continues in cycling service, or resumes base-load operation at some point.

Project participants:
Eric Pigman, plant engineer
Chad Harrison, maintenance manager
Scott Courtois, I&C technician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With faster start-ups,
Once Through Steam Generators
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Triple-redundant sodium analyzers protect equipment, personnel

Best Practices Award

Challenge. Newington Energy Facility's steam-turbine condenser has nearly 9000 titanium B338 Gr 2 tubes with an 0.020-in. wall; its saltwater cooling tower operates at approximately two cycles of concentration. The plant as-built provided for monitoring of condensate pH and specific and cation conductivity—but not sodium. The distance from the condenser to the analyzers in the sample laboratory was such that a step change in concentration would take about 45 minutes to detect. Therefore, one of the first modifications made to the facility was installation of a condensate sodium analyzer and cation conductivity analyzer in proximity to the condensate pump discharge. The analyzers were wired to the DCS and signals transmitted to the PI data historian.

The condensate sodium and cation conductivity analyzers were pivotal in providing quick, reliable identification of a sodium excursion during the plant's first condenser tube leak in 2008. Once the instrumentation readings were confirmed, it allowed operations to safely shutdown the facility within 45 minutes in a controlled fashion to prevent steam system equipment damage.

The analyzers again protected the plant equipment in 2012 when a tube "weeper" was detected, allowing site staff to plan a maintenance outage to locate and isolate the tube leak. In this instance, it was estimated that the leakage rate of circulating water into the condensate was less than 5 ml/min.

As the adage "Murphy's Law" is professed, condenser leaks won't occur on a weekday morning when the plant is fully staffed and additional personnel are available to assist with troubleshooting and analysis. Leaks will occur during a weekend midnight shift when operations staff is reduced and where the decision-making matrix is based upon available information streaming into the operating console, operator training, alertness, and experience.

Considering the plant's cycling operation, condenser materials, previous condenser tube leaks, combined-cycle fleet experience with saltwater condensers, and single-point of analysis for condensate system purity, the analyzers had become critical to the protection of steam-cycle equipment. Facility management decided that a more robust detection design was needed to provide the operations information necessary for safe, reliable facility operation. A triple-redundant analyzer system with voting logic was needed for this application.

Solution. Site personnel worked with two reputable vendors to install demonstration sodium analyzers at the plant. They were operated for approximately three weeks, providing staff the opportunity to evaluate both analyzer response to daily cycling and maintenance and calibration requirements. Results of the demonstration units were compared to those from the existing analyzer. Ultimately, an updated version of the existing analyzer was chosen—the Thermo Scientific 2111XP.

Since conductivity analysis technology is relatively straight forward, the site simply added two more analyzers alongside the existing one (Fig 8). The sample cabinet was re-tubed to accommodate the two additional cation conductivity analyzers and refillable cation exchange columns (Fig 9).

A plant I&C technician programmed the triple-redundant voting logic to the DCS for both the condensate sodium and cation conductivity analyzers. The resulting triple-redundant system will provide objective information when faced with a potential saltwater intrusion. This better protects equipment and relieves the operations staff from having to decide whether or not to trust the analyzers and shut down the plant.

Results. The triple-redundant analyzers are in a short "break-in" period where the analyzers are being monitored to ensure that no unnecessary trips take place. This period is instrumental to understanding the stability of each analyzer, as well as the relative analysis difference among the analyzers, since the typical condensate sodium concentration is less than 0.20 ppb. Next step is to enable the DCS voting logic to automatically initiate a plant shutdown if the sodium analyzers and cation conductivity analyzers indicate a saltwater intrusion into the condensate system.

Principal participants:
Joshua Leighton, operations manager
Scott Courtois, I&C technician
Eric Pigman, plant engineer

8, 9. Two more sodium analyzers were installed alongside the existing one (left) and triple-redundant voting logic was implemented. The sample cabinet was re-tubed to accommodate the two additional cation conductivity analyzers and refillable cation exchange columns (right)

Klamath

1, 2. Klamath Cogeneration Plant's 501FD3-powered combined cycle is in the foreground, the FT8 TwinPacs near the top of the site photo above; peaking units are at the left

Klamath Generation Peakers, Klamath Cogeneration Plant

Iberdrola Renewables

Site consists of a 100-MW, gas-fired, four-unit, simple-cycle peaking plant and a 500-MW, gas-fired, 2 × 1 combined-cycle cogeneration plant located in Klamath Falls, Ore

Plant manager: Ray Martens

Replacing a closed-code FT8 control system

Best of the Best Award

Challenge. The control system supplied by OEM Pratt & Whitney for the two FT8 TwinPacs at Iberdrola Renewables' Klamath Cogeneration Plant was experiencing obsolescence issues and required a software upgrade. It had become cumbersome to use with poor graphics, poor trending functions, and a closed architecture. This made troubleshooting difficult and delayed the identification and correction of problems. Additionally, changes to facility operation required OEM input and approval, limiting the plant's ability to understand exactly how the peaking units were designed to run and how to make operational improvements.

Solution. Once the warranty period was completed, being tied to the OEM for approval of plant changes became cumbersome, costly, and unacceptable. New power purchase contracts required improvements in engine starting and operating reliability. A cost/benefit analysis suggested a control-system upgrade. Three options were considered:

- An HMI software upgrade by P&W. It included new server machines and software but maintained the remaining hardware and still had closed-code architecture.
- A completely new OEM system that replaced hardware and software, but again with closed architecture.
- An entirely new, standalone DCS system with an open-code architecture offered by ABB. The major risk associated with this option was that, to the plant's knowledge, this had never been attempted by anyone.

The Klamath plant site includes a combined cycle with an ABB Bailey DCS control system (Figs 1, 2). Installing an ABB DCS would seamlessly integrate the two facilities. Ultimately, the ABB DCS was the option selected. Klamath had a very good relationship with ABB and all parties involved recognized the challenges of retrieving the necessary logic to recreate it in the new control system.

Some critical system logic had to be developed with the ability to see the existing logic, such as: (1) IGV/VSV and fuel valve curves, (2) surge protection, (3) cold air buffer logic, (4) thrust-balance valve control, (5) evaporative-cooler controls, and (6) ammonia and SCR control scheme.

Without the ability to see the logic in action, or a trending function to view system performance, creativity was required for data-gathering. One method used was to set a video camera in front of the HMI and record starts, stops, and load changes. From these videos, engineers were able to recreate the actions of the controls.

Specific log sheets were developed for the operations department to fill out during plant runs when no engineering was available. Plus, instrumentation and metering was set up in the field to monitor changes in signals that were not viewable from the con-

Mark Mayers and Greg Dolezal (l to r)

trols. Watch Windows software also was used to provide necessary balance-of-plant (BOP) data.

While data were being collected, the cabinet layout was designed and cable runs were considered. Plus, an addition to the control building was planned for these reasons:

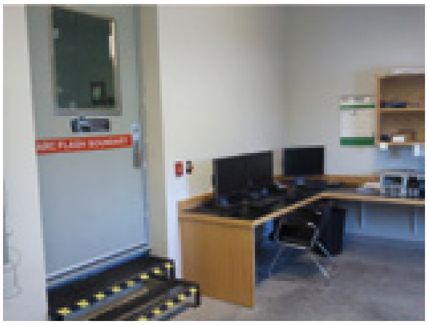
- To reduce the time required for the cutover outage. The ability to have the cabinets in place, cable trays installed, wire pulled, and a desk with layout space contributed to this goal (Fig 3).
- To allow the operator to control the plant from a desk-mounted HMI located at a safe distance from the arc-flash potential of the Pratt & Whitney control cabinet (Fig 4). The existing cabinet had the HMI directly in front of the 13.8-kV generator breaker. All TwinPac control cabinets supplied by Pratt & Whitney place the operator inside the arc-flash zone, presenting a serious hazard during operation of the generator breaker.

The option of having ABB provide a pre-manufactured building was evaluated. A cost/benefit analysis proved it was less expensive to construct a building with local contractors than to purchase, transport, and install a prefab unit (Fig 5). Plant staff contributed to the cost saving by doing the electrical install, including NERC-required cameras and badge readers.

Additionally, the purpose-built structure is larger than any building that would be capable of over-the-road transport. The larger floor plan accommodated engineers and the drawings required in support of the commissioning effort. This space is now used for storage.

Another major upgrade permitted by the control-system change-out was replacement of the thrust-balance valve actuator. The original actuator was pulse-activated and only had limit switches to indicate "open" or "shut." A new EIM actuator with full-range feedback was installed (Fig 6). The controls project also allowed engineers to create a standard PID loop for more accurate control.

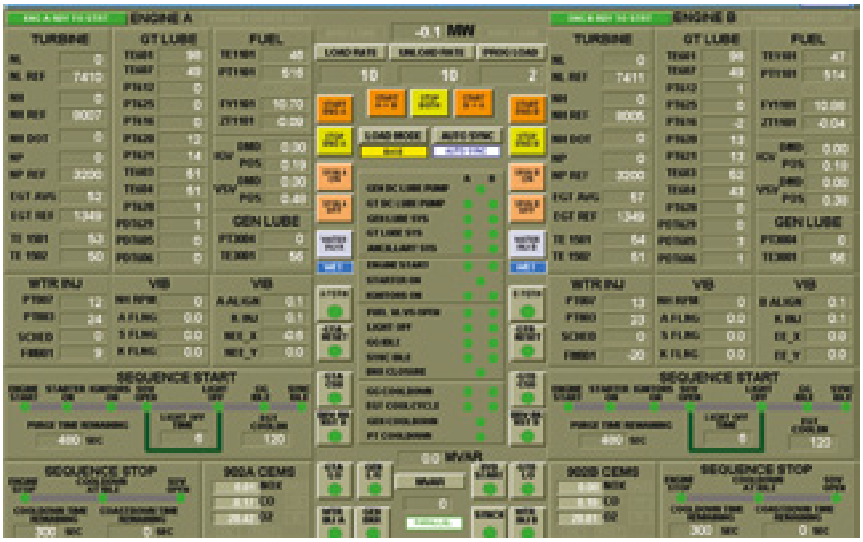
3. Cabinets and server rack were installed in the new building before the cutover outage began



4. Operator station is located outside the arc-flash zone

5. Control building addition with cable trays in view

6. Thrust-balance valve actuator retrofit has improved peaker reliability



7. Overview graphic provides a snapshot of plant operations

Demonstrated results included the following:

- Open architecture and access to system knowledge provide technicians an intimate understanding of every system in the plant and give them the ability to modify logic and make plant improvements.
- The ability to tune the engines, make BOP changes, and modify graphics to aid in operations now resides at Klamath (Fig 7).
- Link-up of the new control system with the PI historian provides the ability to store and retrieve data for troubleshooting and performance enhancements.
- The thrust-balance valve actuator improvement eliminated a major contributor to poor reliability.
- Removing the ammonia-control PLC and integrating that system into the DCS has produced meaningful positive results: New graphics, transmitters that replaced switches, and more precise valve controls enabled plant personnel to greatly improve system performance. The water injection curve is now under plant control, allowing greater turndown while staying in emissions compliance and increasing the operational flexibility needed to extend revenue opportunities.
- Alarm set points can be modified, along with the nomenclature of the alarm, to better assist operators in diagnosing problems.

Project participants:

Ray Martens, plant manager
Greg Dolezal, maintenance manager
Bruce Willard, operations and engineering manager
Mark Mayers, senior plant technician (electrical)

Encogen

> **Encogen Generating Station**
> *Puget Sound Energy*
> 167-MW, dual-fuel, 3 × 1 combined-cycle located in Bellingham, Wash
> **Plant manager:** Thor Angle

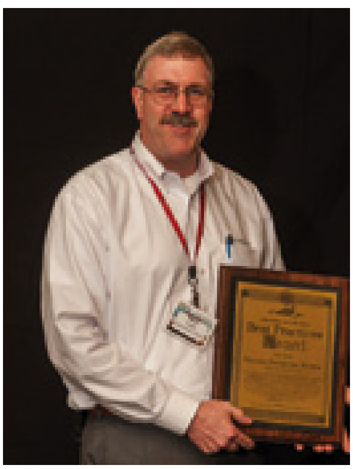
Transitioning a legacy base-load plant to cycling duty

Best of the Best Award

The challenge at Puget Sound Energy Inc's Encogen Generating Station was typical of what others in the industry are asking today: How do you take a base-load combined cycle powered by legacy frame engines and make it economically and operationally relevant in today's energy market? In this case, the plant was a 3 × 1 combined-cycle cogeneration facility with Frame 6 gas turbines that went commercial in July 1993.

It supplied up to 130,000 lb/hr of steam and 3600 gpm of hot water to a paper mill across the fence and sold "surplus" electricity (up to 137 MW) to the local utility under a power purchase agreement (PPA) mandated by Purpa (Public Utility Regulatory Policies Act). The host utility purchased the plant in 1997.

During the PPA period, annual plant capacity factor was 95% and above. Plant design and operating procedures dictated a minimum unit run time of 24 hours after a start. The mill closed in July 2008 and the export of thermal energy ceased. Since then, the plant has been dispatched based on natural-gas and electric-power prices. Traditionally, the utility has had a winter-peaking profile, although economic dispatch opportunities are relatively common in July, August, and September.



Thor Angle

Challenge. Plant personnel identified the following as today's needs: (1) Provide the flexibility to operate only during periods of peak load, and (2) maximize wind-generation balancing capacity. Among the goals were the following:

- Reduce the unit minimum run time to four hours.
- Reduce the plant minimum run time to six hours with staggered unit starting.
- Be able to operate within permit limits between 20 and 170 MW.

Steps taken and projects completed to reduce minimum run times, increase flexibility, and make faster starts:

- Relocated HRSG drum vents to ground level, eliminating the need for operations personnel to climb to the tops of the boilers during startup. Also redesigned startup vents to reduce noise levels, thereby allowing start-ups and shutdowns at any time. Previously, starts were permitted only during the day.
- Reduced boiler purge time from 20 minutes to 10.
- Increased GT ramp rate to track, as closely as possible, the maximum allowable pressure rise in the HP drum.
- Control-system upgrade (Wonderware): Networked all PLCs to allow central control and eliminate local-only control—this to free up operator time. The BOP PLCs had not been networked.
- Installed manual IP-steam-injection warm-up lines.
- Rebuilt HP-to-IP steam letdown stations to allow more precise warm up of the steam injection system.
- Changed boiler chemistry program from coordinated phosphate to AVT(O). With the former it took more than 24 hours to establish stable chemistry following a start-up. Other benefits/enhancements included the following:
  1. Reduced the number of chemical day tanks for the boilers from nine to three.
  2. Developed a system to recirculate hotwell and batch-treated water to drums to keep them at the proper levels and eliminate pre-start filling.
  3. Installed the means for automated condensate chemical (amine) injection.
- Engine upgrades included coatings to resist the effects of cycling.
- Training was a major initiative to prepare employees for the new operating paradigm. Program highlights included the following:
  1. Attended an industry workshop to learn how to lay-up, cycle, and improve HRSG chemistry.
  2. Engaged a consultant to audit startups and recommend procedures on how to minimize cycling impacts on HRSGs.
  3. Developed new standard operating procedures.
  4. Implemented a computerized

Annual operating stats

Year	Capacity factor, %	Starts	Hours per start
2008	3.6	15	21.3
2009	30.1	34	77.6
2010	20.3	59	30.1
2011	8.6	31	24.2
2008-2011 avg	15.7	35	39.2
2012	11.7	74	13.8

maintenance management system that incorporated predictive maintenance practices.

5. Developed plant procedures to encourage cross-craft qualification and promoted journey-level inside and outside operators to permit plant startup with only two people.

Results met expectations: The three goals stated in the opening remarks were achieved. Operating data over the last five years revealed the following:

- The plant started only 15 times in 2008, 74 times in 2012 (table).
- The number of hours per start peaked in 2009 at 77.6. In 2012 the combined cycle ran only 13.8 hours per start.

One benchmark illustrating the impact of cycling on equipment: For the years 2008-2011, the plant repaired from one to three tube leaks annually; in 2012, seven tube leaks were repaired. Header modifications and changes to operational procedures are ongoing to mitigate the effects of cycling. Despite the uptick in tube leaks, O&M expenses for years 2008 through 2011 and 2012 were about the same.

Remaining objectives include (1) familiarizing trade-floor and generation-desk staff on what the term "flexibility" means regarding combined-cycle operation, and (2) evaluating the steam-turbine warm-up schedule from cold-iron and warm-start conditions.

Project participants:
Lynn Bell, O&M supervisor
Rob Carter, plant engineer
Aaron Karlsson, maintenance planner
Justin Fuller, CT technician
Alan Hall, CT journey worker
Bob Csolti, CT journey worker
Michael Hoyt, CT journey worker
Brian Funk, CT journey worker
Chris Moore, CT journey worker
Matt Summers, CT journey worker
Calvin Stutzman, CT journey worker
Chris Hinricher, CT journey worker
Travis Human, CT journey worker
Chad Hollopeter, CT apprentice
Patrick Regan, CT apprentice
Barbara Zatrine, operations support specialist

Effingham

Effingham County Power

Owned by Southeast PowerGen LLC
Operated by Consolidated Asset Management Services

525-MW, gas-fired, 2 × 1 combined cycle located in Rincon, Ga

Plant manager: Paul Garrett

Reducing LP drum pressure increases cold-weather output

Best of the Best Award

Challenge. Effingham County Power's 2 × 1 F-class combined cycle had lower-than-expected cold-weather electric production because of condensate-system restrictions. The Southeast PowerGen facility, operated by Consolidated Asset Management Services, initially was limited to 517 MW, with a heat rate of 6876 Btu/kWh at ISO conditions, before a gas-turbine (GT) controls upgrade with GE OpFlex increased total plant generation by approximately 9 MW.

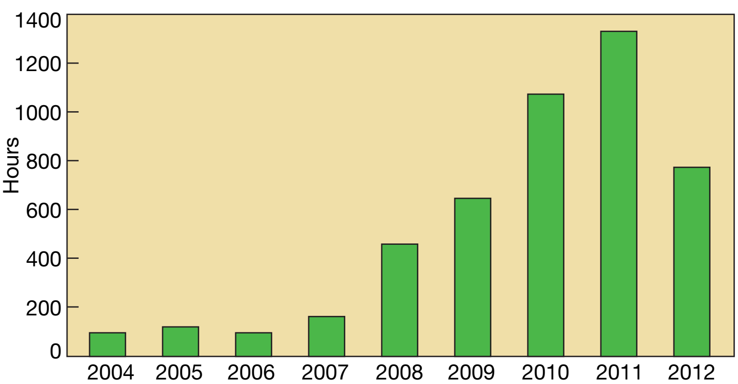
The winter following that upgrade, plant staff determined cold-weather performance was limited by the condensate system. Specifically, above 50F ambient, plant electric production was constrained by GT output, below 50F by the condensate system's ability to supply a sufficient amount of water to the LP steam drums (Fig 1).

The HRSG's LP preheater bypass originally was programmed for a set point of 75 psig to protect against cold-end corrosion. Actual LP drum pressures at base load were 55-57 psig, so the LP preheater bypass valves typically remained closed during plant operation. Above 526 MW, the condensate system was unable to maintain the desired LP-drum water levels—even with all three 50% condensate pumps in operation. This only limited output during winter operations because of the plant's warm geographical location.

However, when planning the addition of inlet chillers to increase GT output, plant personnel noticed that the condensate-system limitation would

How operating conditions impacted plant output

Scenario	LP drum, psig	Output, MW (net)	Heat rate, Btu/kWh (gross)
Commissioning (contract conditions)	55-57	517	6876
After GT tuning (contract conditions)	55-57	525	6850
At 50F ambient before controls upgrade	55-57	526	6850
At 50F ambient after controls upgrade	40	535	6850
At 30F ambient after controls upgrade	40	550	6850



1. Operating hours at less than 50F ambient have increased dramatically in the last few years

Paul Garrett, Bob Kulbacki, and Nick Bohl (l to r) affect operations over more run time because of a planned change in the winter operating profile from cycling to base load. Initial action involved evaluating the cost of upgrading the condensate system to boost its capacity.

Solution. Effingham staff discussed various alternatives and believed condensate return flow could be increased, without capital expenditure, by lowering LP drum pressure. Plant technicians experimented over a period of several days by operating the LP preheater bypass manually to reduce LP drum pressure. By comparing condensate flow versus LP drum-level control valve position at various drum pressures, they verified that condensate return flow rates could be increased. For the lower LP-drum pressures, condensate-pump operating conditions were within the allowable pump curves, and adequate NPSH was verified for the boiler feed pumps.

Results. Using LP preheater bypass valves to lower LP drum pressure to 40 psig, plant output at 50F ambient was increased from 526 to 535 MW. At 30F, production could be increased to 545 MW with only two of the three condensate pumps running; with all three in operation, 550 MW was possible (table). Providing new logic for the automatic operation of LP-preheater bypass valves gives operators multiple options by simply changing the pressure set point. This operating change had a negligible impact on plant heat rate and was done at essentially no cost.

Project participants:
Richard Blankenship
Don Johnson

2. Motor control center

3. Grounding trainer

Equipment supports core-skills training, proficiency

Best of the Best Award

Effingham County Power relies on multi-skilled GT technicians to operate the plant. Their core skills are electrical, I&C, and mechanical. Skills training consists of a series of computer-based lessons and exams divided into modules. After each module is completed, the technician performs the practical job tasks assigned. When all the modules have been completed, a series of so-called job performance measures (JPMs) are completed as a final evaluation. The company's training coordinators developed the JPMs for each core skill to ensure consistent minimum standards among all technicians throughout the company's facilities.

Challenge. The company's overall challenge was to safely and effectively train all operators without affecting plant availability. This was difficult for several reasons, including these:

- A goal of the training program is to have technicians perform hands-on training and evaluations rather than simulated tasks. However, opportunities to train on actual equipment were limited because of the plant's operating schedule. Plus, the program was designed to allow qualified technicians to practice their skills to maintain proficiency whenever their schedules permitted.
- The training program is arranged to evaluate the ability of technicians to troubleshoot equipment faults and determine their root cause. In testing the technician's hands-on knowledge, training coordinators found it difficult to insert anomalies.
- Technicians are required to set up switches and transmitters for a specific application. Testing on installed switches and transmitters, which already are set up to perform a specific function, made it difficult to thoroughly evaluate an individual's skills.
- For some of the job tasks, the technician only used the acquired skills on an annual basis—for example, hanging high-voltage grounds and inspecting dc motor brushes. Training on, and evaluation of, these skills was difficult because it required placing a clearance on systems that made the plant unavailable for dispatch.

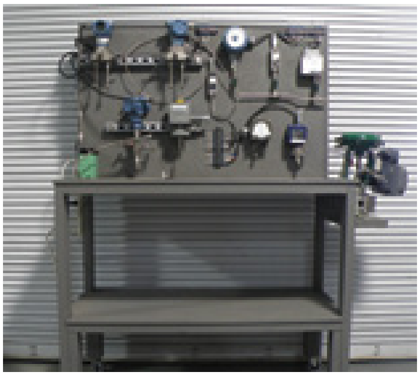
Solution. Project goal was to gain access to equipment conducive to realistic training and to incorporate as many of the JPMs as possible. The first action taken was to contact a local technical college that offered electrical, mechanical, and I&C degree programs. While the labs and training facilities met expectations, employee work schedules and travel distances made this option infeasible.

Next, several companies that supply training labs to colleges and industrial companies were contacted. The high cost of equipment nixed this option. An alternative was to contact various vendors for quotes on powerplant equipment suitable for the training planned. Suppliers were told the equipment did not have to be operational because the use was disassembly/reassembly training. However, no castoffs were available; new equipment would have to be purchased at cost. Budgetary considerations would severely restrict the amount of equipment that could be purchased.

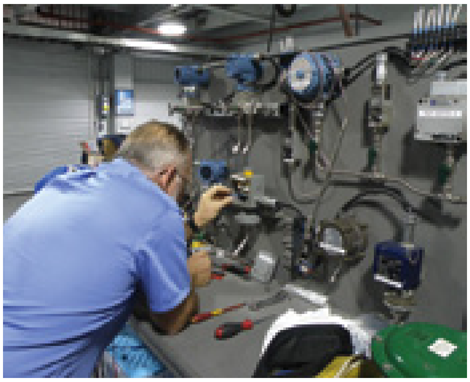
The decision made was to construct a training-lab bench in-house to minimize program cost. The project started by collecting switches and transmitters throughout the plant that were not operating correctly. Pumps and valves that had been removed from service also were gathered up. Several salvage companies and equipment dealers with Internet sites were contacted when searching for a specific item. Prior to purchase, prices were compared to those available from an authorized vendor. In all cases, there was a significant cost savings when purchasing online.

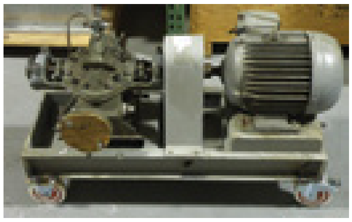
Construction of equipment stands followed. Because the company's plants do not have dedicated training areas, the equipment stands were made mobile to facilitate movement. Several of the training stands are shown in Figs 2-8. This equipment can support training on numerous JPMs. For example, the electrical trainer in Fig 2 is designed to test an employee's skills in troubleshooting a faulty breaker to the component level, as well as testing

4. MOV trainer



5. I&C training bench





6. Pressure-switch calibration bench (left)
7. Pump and motor skid (above)
8. Alignment trainer (right)

skills in measuring a motor's electrical performance.

One of the simplest trainers constructed is used to evaluate a technician's ability to hang grounds on high-voltage conductors (Fig 3). Three sections of conduit are mounted on the overhead of the back porch alongside the training area with a section of grounding cable. This set-up allows trainees to practice handing grounds using a hot stick and arc-flash clothing without affecting plant operation. The grounding trainer has been used for initial training, as well as for refreshing an individual's skills prior to hanging grounds for a plant-wide outage.

The I&C training bench has several transmitters and switches installed (Fig 5), providing an opportunity to improve multiple individual skills at one location. It also has a low-voltage power supply so the transmitters operate the same as if they were in the field.

Results of this project were immediate. Trainees are able to practice their skills at any time without affecting plant operation. In addition, they can come into work, outside of their normal shift schedule, to hone skills. Subject-matter experts are available for assistance when needed. The program also is paying dividends by enabling qualified employees to maintain their proficiencies.

Project participants:
Nick Bohl, production manager
Bob Kulbacki, production team leader
Bill Beahm
Cheryl Hamilton
Alan Sparks
Sean O'Neill

Arc-flash data sheets, labels create a user-friendly program

Best Practices Award

In 2011, an outside contractor performed a "Short-Circuit, Protective-Device Coordination and Arc Flash Study" that included placing arc-flash data/summary labels on all surveyed equipment. The equipment and labels are located throughout the plant.

Challenge. Conducting a proper pre-job brief involving energized electrical equipment was difficult without the shock hazard, shock boundaries, and proper personal protective equipment (PPE) information readily available. Data had to be retrieved from the affected equipment in the plant and then used to conduct the pre-job brief. Personnel observing maintenance activities could not verify that the proper controls were being used without having to review the data on the posted arc-flash labels.

In addition, the plant only had two sets of arc-flash PPE, both rated at 65 cal/cm^2, and two sets of Class 1 electrical gloves. This PPE was used for all work on energized electrical equipment. This was difficult when the technician was required to perform maintenance on small components with the bulky Class 1 gloves and could potentially cause heat stress because of the high temperatures and humidity.

The outside contractor provided onsite training for all plant personnel. The training consisted of arc-flash terms, definitions, and how to work on energized electrical equipment in accordance with NFPA 70E.

Solution. The plant's arc-flash safety program had to be revised—not only to update the plant's existing procedures, but also ensure that equipment hazards, shock boundaries, and personal protective equipment data were available in a centralized location, supporting proper safety review prior to working on energized electrical equipment.

Step 1: Gather all the hazard, shock, and PPE requirements from the equipment survey. This information was then used to create a spreadsheet listing all of the plant's equipment and a data sheet for each individual component (Fig 9). The spreadsheet contains the basic arc-flash data for all the equipment to be used as a quick reference.

The data sheets contain the detailed arc-flash evaluation information, shock-boundary evaluation data, and all breakers located on this equipment (Fig 10). The spreadsheet and data sheets are placed in a binder maintained in the control room segregated by voltages. This helps in locating equipment data sheets quickly for required maintenance.

The plant's arc-flash safety program was revised to incorporate the latest NFPA 70E requirements for working on energized equipment and used data from the plant's arc-flash study. A new arc-flash safety checklist was created for use while conducting the pre-job brief for working on energized equipment. The terminology found on the labels and data sheets was employed in the new checklist to ensure accurate hazard evaluation.

Step 2: Determine the appropriate PPE levels for the hazard categories identified within the plant. There were several requirements considered when purchasing the PPE. They included which hazard-risk categories could be covered by the same PPE levels. It was determined that common sizes could be used by the majority of the technicians to perform work.

BUS NUMBER	BUS NAME	FLASH HAZARD BOUNDARY	FLASH HAZARD BOUNDARY AT18"	CATEGORY
1-EQ-521-CPL-1003	CT1 Accessory Compartment Sump Pump	5 inches	0.12 cal/cm²	0
1-EQ-521-CPL-2001	CT2 Accessory Compartment Sump Pump	5 inches	0.12 cal/cm²	0
1-EQ-543-CMP-9001A	"A" Air Compressor Local Disconnect	9 inches	0.36 cal/cm²	0
1-EQ-620-DS-9001	Circ Water Pump 13.8kv XFMR Primary DS	303 inches	9.51 cal/cm²	3
1-EQ-624-SWG-5001	Inlet Chiller 4160v Switchgear	512 inches	15.6 cal/cm²	3
1-EQ-624-SWG-9001	13.8kv Switchgear	1129 inches	34.1 cal/cm²	4
1-EQ-624-SWG-9002	4160v Switchgear	808 inches	24.7 cal/cm²	3
1-EQ-624-SWG-9003	Circ Water Pump 4160v Switchgear	142 inches	4.53 cal/cm²	2
1-EQ-625-MCC-9001	BFP/CCCW 4160v MCC	221 inches	6.98 cal/cm²	2
1-EQ-625-MCC-9002	Circ Water Pump 4160v MCC	142 inches	4.53 cal/cm²	2
1-EQ-630-ASU-9001	STG#1 MCC ATS	81 inches	14.1 cal/cm²	3
1-EQ-630-ASU-9004	Admin Building ATS	205 inches	64.7 cal/cm²	DANGER
1-EQ-630-DS-9002	Cooling Tower 13.8kv XFMR Primary DS	302 inches	9.48 cal/cm²	3
1-EQ-630-SWB-9001	Back-up Power Switchboard	256 inches	94.3 cal/cm²	DANGER
1-EQ-631-RCP-1001	HRSG2 Ammonia Fan Welding Receptacle	6 inches	0.2 cal/cm²	0
1-EQ-631-RCP-1002	CT2 PEECC Welding Receptacle	5 inches	0.16 cal/cm²	0
1-EQ-631-RCP-2001	CT2 Turbine Compartment Welding Receptacle	6 inches	0.2 cal/cm²	0
1-EQ-631-RCP-2002	HRSG2 BFP Welding Receptacle	5 inches	0.16 cal/cm²	0
1-EQ-631-SWB-1001	CT1 480v Power Distribution Power Panel	12 inches	0.64 cal/cm²	0
1-EQ-631-SWB-2001	CT2 480v Power Distribution Power Panel	12 inches	0.63 cal/cm²	0
1-EQ-631-SWG-1001	CT1 PEECC 480v Supply Switchgear	267 inches	99.5 cal/cm²	DANGER
1-EQ-631-SWG-2001	CT2 PEECC 480v Supply Switchgear	266 inches	99.3 cal/cm²	DANGER
1-EQ-631-SWG-9001	BOP 480v Supply Switchgear	152 inches	39.5 cal/cm²	4
1-EQ-631-SWG-9003	Cooling Tower 480v Supply Switchgear	284 inches	110 cal/cm²	DANGER
1-EQ-635-MCC-0001	STG#1 MCC	80 inches	14 cal/cm²	3

9. Arc-flash spreadsheet contains all the hazard, shock, and PPE requirements for each piece of equipment surveyed

DEMINERALIZED WATER MCC (1-EQ-635-MCC-9002)		
ARC FLASH EVALUATION		
Flash Hazard Boundary - 24 inches		
Flash Hazard Boundary at 18 inches - 1.95 cal/cm²		
Hazard Risk Category - 1		
FR Shirt and Pants (AR-4)		
Hardhat and Safety Glasses		
Faceshield (AR-4)		
Hearing Protection		
Class 00 Gloves with Leather Protectors and Leather Work Shoes		
SHOCK BOUNDARY EVALUATION		
480VAC	Shock Hazard When Cover is Removed	
Class 00 Gloves with Leather Protectors		
42 Inch	Limited Approach (Fixed Circuit)	
12 Inch	Restricted Approach	
1 Inch	Prohibited Approach	
BREAKER	**TAG/SYSTEM**	**CUBICLE**
Demin Water MCC Main Transformer Breaker		02FH
Demineralized Water Transfer Pump "A"	1-EQ-514-P-9001A	01FD
Demineralized Water Transfer Pump "B"	1-EQ-514-P-9001B	01FF
Fuel Gas Regulating Station 112.5KVA Transformer		04FC
Fuel Gas Metering Station 75KVA Transformer		04FGR
North Roadway Lighting		04FIL
Power Receptacle "B" Demin Pump Area	1-EQ-635-RCP-9004	04FAR
Power Receptacle "A" Raw Water Pump Area	1-EQ-635-RCP-9003	04FAL
Raw Water Booster Pump "A"	1-EQ-512-P-9002A	01FH
Raw Water Booster Pump "B"	1-EQ-512-P-9002B	01FJ
Raw Water Forwarding Pump "A"	1-EQ-512-P-9001A	03FA
Raw Water Forwarding Pump ""	1-EQ-512-P-9001B	03FE

10. Data sheet contains detailed hazard, shock, and breaker information

Two sets of PPE were purchased for Hazard Categories 0, 2, 3, and 4. Hazard Category 2 PPEs are used for Hazard Category 1 work, because they have similar requirements. These PPEs were placed in individual bins for easy storage and retrieval when needed, and to facilitate monthly inventory and inspection requirements (Fig 11). All the PPE is stored in a centralized climate controlled room, with all personnel having access.

Four sets of Class 00 and two sets of Class 2 electrical gloves were purchased for use by plant personnel while performing electrical work. The reasoning behind just two categories is that the Class 2 affords the highest protection for the technician when opening air disconnects and performing the live-dead-live test prior to hanging equipment grounds.

In addition, Class 00 gloves give the technician the manual dexterity to work on small items of energized electrical equipment. Plant personnel are not trained to work on electrical equipment rated more than 480 V, so higher-class electrical gloves are not required.

Multiple sets of gloves were purchased so that more than one job involving energized electrical equipment could be performed at the same time. Also, this allows gloves to be sent off to the testing laboratory as required, while keeping an inventory on site to perform maintenance as needed.

Step 3: Design and purchase 3 × 5-in. hazard-risk category labels to place on the affected equipment; this enables personnel to see the category of equipment being worked on from a distance. Hazard Categories 0, 2, 3, and 4 and danger labels were purchased and placed on the equipment

11. PPE storage system allows for easy access and retrieval and facilitates inventory and inspection requirements

12-14. Labeling is critical to the success of the plant's safety program

corresponding to the hazard category evaluated by the arc-flash study. These labels are located near the arc-flash data labels to assist the technician.

Labels were also placed on bins for the associated hazard-category PPE. This was done to help the technician verify the correct PPE for the equipment they were assigned to work on when approaching it.

Final step: Conduct arc-flash safety training for all plant personnel. This was conducted during several of the plant's monthly safety meetings as the various phases of the program were completed. The first month's training was on the new procedure and the data sheets that were created in the control-room binder. Prior to the next meeting, the plant received the new arc-flash PPE and training was provided on use and proper care. After all the hazard-risk category labels were in place, and the designated PPE storage area assigned, the final phase of the training was conducted.

Since the new arc-flash safety program was being used throughout the training phase, feedback was welcomed from the technicians who had performed work on energized electrical equipment. This feedback was then evaluated and changes to the program were implemented, if deemed necessary.

Results. Prior to the changes in the plant's arc-flash safety program, it would take several minutes for the data from the posted labels to be retrieved to conduct a pre-job brief, increasing turnaround time. Also, when planning to work on energized electrical equipment, the technician did not know the level of PPE required until reviewing the posted arc-flash safety labels. With the information located in the control room, it is reviewed quickly and equipment down time is minimized.

With the new PPE onsite, technician comfort has improved substantially—especially when working in the heat of the day. The hazard segregation and storage design of the PPE allows quick retrieval in the event of an emergency. With the new Class 00 electrical gloves, the safety of the technician has been improved when working on small breaker parts.

In addition, during the pre-job briefs, we can inspect any outside contractor's PPE to ensure they meet the plant's arc-flash safety program requirements. This inspection can be performed prior to them entering the plant, thus minimizing work stoppages and safety near misses.

The new hazard-risk category labels make all personnel aware of risks when monitoring work on energized electrical equipment. It also helps technicians verify whether they have the proper PPE prior to starting work.

Project participants:
Nick Bohl, production manager
Bob Kulbacki, production team leader

Better organization of paperwork in the control room pays dividends

Challenge. The large number of permits, clearances, and preventive-maintenance work orders generated at Effingham County Power demanded better organization to ensure accurate accountability in the control room. In the past, several binders were maintained for hot-work, confined-space, and lock-out/tag-out (Loto) programs.

The company's procedures require hot-work and confined-space permits to be posted at the jobsites for personnel to review prior to and during maintenance. Copies of these active permits were maintained in the program's binder in the control room. Once work was complete, and the permits no longer required, they were closed out by removing them from the program folder and placed into a designated "closed" folder.

Loto paperwork also was maintained in a binder in the control room. This paperwork had to be removed from the binder anytime a Loto change was necessary, an employee or contractor had to be signed off or onto the Loto, or a request to walk down the Loto was made. But because all clearances were retained in the same binder, retrieval of these forms became time consuming and cumbersome, especially during outages. Plus, the forms often were damaged by constant removal from the three-ring binders.

All of the facility's active PM work orders were kept in a single pocket wall file inside the control room. It included all the weekly, monthly, quarterly, semi-annual, and annual PMs scheduled. Having all the PMs in the same wall file, ensuring preventive maintenance was being performed on time was difficult. There were many occasions where a weekly PM would be missed because of this process.

This overall system of organization not only made dealing with permits and PMs difficult, it also required the use of six different binders which took up a large amount of space inside the control room.

Solution. The need for better organization was a must, along with wanting to reduce the number of binders in the control room. Plant personnel decided that the best way to organize paperwork and utilize less space was to install multiple pocket wall files in the control room (Fig 15).

15. Plant permit file system, mounted on a wall in the control room, greatly improved access to critical paperwork

The first step was to determine the number of pocket wall files required and the best location for easy access and visibility. The PMs were separated by weekly, monthly, quarterly, semi-annual, and annual periodicities. This would allow the control room operator (CRO) and team lead to determine if any PMs were required for completion during their shift, when they came on duty. With PMs separated by periodicity, managers could quickly determine if PMs were overdue without sorting through all the work orders. An empty wall pocket meant there were no PMs due for that period.

The safety program pocket wall files were mounted directly in the control room for visibility and easy access. Both the hot-work and confined-space programs were assigned two pocket wall files. One labeled active and the other inactive. The active pocket wall file contains blank permit forms and an index listing permit location, plus establishment and closure dates. All closed permits were placed in the inactive pocket wall file for final review by designated personnel.

The Loto program was assigned five pocket wall files; combustion turbine 1, combustion turbine 2, steam turbine, balance of plant, and inactive. Active clearances were placed into the appropriate pocket wall file for the assigned unit. Forms were retrieved as needed for review and when workers were required to sign onto and off of the clearances. When clearances were closed they were placed in the inactive pocket wall file awaiting final review. Once the final review is complete, the clearance is filed per plant procedure.

Results. Immediate results noticed were having the active permits, clearances, and PMs readily available. The CRO and team lead were able to see forms easily and determine which PMs required completion on their shift.

During high maintenance periods, several clearances were retrieved at a time by personnel, increasing process efficiency. With all clearances organized by unit they were easily monitored and controlled.

Another benefit of having inactive permits placed in pocket wall files is it enables a quick review and comparison to the program index, to determine if a permit is missing or active. Finally, the number of binders maintained in the control room has been reduced, making more efficient use of workspace.

Project participants:
Nick Bohl, production manager
Bob Kulbacki, production team leader

CAMS celebrates its sixth anniversary with eight Best Practices Awards

Consolidated Asset Management Services, privately held and headquartered in Houston, has experienced significant growth and success since its formation in 2007. The company currently operates power-generation facilities at 30 sites in the US—including Effingham County Power, Lea Power Partners, Sabine Cogen, and Crockett Cogeneration.

These four plants together received eight Best Practices Awards—including two Best of the Best—during the ninth annual presentation luncheon hosted by Goose Creek Systems Inc at the CTOTF's™ Spring Turbine Users Conference, April 8, in Myrtle Beach, SC. The details:

Crockett Cogeneration LLC

FREIF North American Power I LLC

In conjunction with the California Maritime Academy, plant personnel developed and implemented a successful, hands-on engineering internship program to train students in the management, operations, and maintenance skills required at power facilities.

Effingham County Power

Southeast PowerGen LLC

Three awards:

In accordance with the guidelines of NFPA 70E, plant personnel developed and implemented an extensive arc-flash safety program consisting of a comprehensive component database, a standardized safety checklist, proper protective equipment, hazard risk labeling, and operator training.

Challenged by reduced output at low ambient temperatures, plant staff initiated and implemented modifications to the LP preheater bypass controls to optimize the flow of condensate to the LP steam drum. Result: A gain in output of up to 24 MW during cold-weather operations.

Recognizing the importance of fostering and maintaining a proficient, multi-skilled workforce for effective operations, plant personnel developed and implemented an extensive onsite training program complete with replica equipment, designated subject matter experts, and computer-based learning.

Lea Power Partners LLC

FREIF North American Power I LLC

Three awards:

In order to ensure efficient ammonia delivery, plant personnel installed a tank level transmitter to facilitate communication with the dispatcher, eliminating potential upsets in operation from ammonia shortages and reducing the environmental risks associated with using chemical totes.

Installation of a bulk hydrogen storage tank for the plant's steam turbine/generator, replacing the original, labor-intensive bottle rack system, eliminates the risk of operator injury, dramatically reduces operation and maintenance man hours, and produces significant cost savings.

Burdened with excessive wastewater disposal costs, personnel worked closely with state agencies and a local landowner to provide plant discharge water directly to an adjacent, 80-acre farm for irrigation. Results include a five-month project payback, virtual chemical and maintenance cost elimination, and increased operator availability.

Sabine Cogen LP

ArcLight Capital Partners and NRG Energy Inc

In-house design and development of a safety database allows plant personnel to effectively record and manage outside contractor information, including insurance documentation and required safety training and credentials for individuals, ensuring streamlined facility maintenance.

CAMS offers a wide range of services to owners of power and oil/gas production assets in the Western Hemisphere and Europe. In addition to operations, the company supports construction management, engineering, equipment repair, and plant overhaul activities.

Roger Schnabel, Tim Hevrin, Joe Sutton, Christopher Sargent, and **Paul Garrett** (top row, l to r); **Eric Garrett, Bob Kulbacki, Nick Bohl,** and **Jim Riddle** (bottom row, l to r)

Johnson County

Johnson County Generation Facility

Owned by Brazos Electric Cooperative Inc
Operated by NAES Corp

263-MW, gas-fired, 1 × 1 combined cycle located in Cleburne, Tex

Plant manager: Joe Booth

Optimizing chiller operation

Best of the Best Award

Brazos Electric Cooperative Inc's Johnson County Generation Facility, operated by NAES Corp, recently installed a 3500-ton chiller on the front end of the 501FC gas turbine serving the 258-MW 1 × 1 combined cycle (Figs 1, 2). Reason: Dramatic fluctuations in ambient temperature made it difficult for the utility to predict day-ahead generation and gas nominations, and to balance electrical load in its territory in real time.

Challenge. While the chiller enabled operators to increase summertime power production and gave dispatchers a predictable output for dispatch, its operation increased station auxiliary load. Another cost to consider: Recharging of the thermal storage tank incorporated into the design of the chiller system. The challenge was to optimize chiller operation for summer peak periods.

Solution. The system was designed to operate in the "partial-discharge" mode (Fig 3), meaning the total amount of chilled water required for cooling gas-turbine inlet air would combine flows from the chillers and from the thermal storage tank. Over time, the cooling capability of the storage tank would be drained—like a battery in a flashlight left on. The only other mode of operation was "tank-recharge," which only could be accomplished with no inlet chilling (Fig 4).

The obvious choice for system optimization: Recharge the tank only during off-peak hours when the cost of power is low and the cycling plant is not in service. The next question was how to efficiently use the capacity of the thermal storage tank. The first step was to create logic in the plant DCS to capture chiller data during the different plant operating scenarios through the summer to guide engineers.

Thinking outside the system design box led plant personnel to what the team believed was the optimal solution (Fig 5). They went against the accepted operations plan in an experiment and took all the chilled water from the storage tank to maintain the temperature set point for turbine inlet air instead of combining flows. This was called the "tank-only" mode of operation (Fig 6).

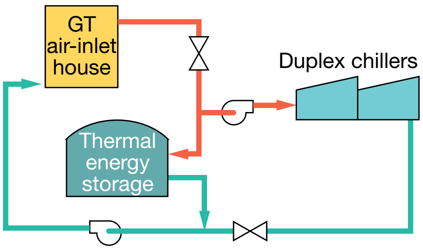
With the VFDs for the thermal tank's chilled-water pumps able to totally control the inlet set point, the 2-MW house load required to run the chillers could be sold. Since this operating mode would reduce the number of hours the thermal storage tank could operate, plant staff set about deciding how best to use "tank-only" operation.

Results. Data collected provided the length of time the "tank-only" mode could be used while still providing sufficient reserve capacity to allow a return to "partial-discharge" operation to complete the chilling cycle. Typically, "tank-only" chilling is used from about 1 to 8 pm, "partial discharge" from 8 pm until unit shut down.

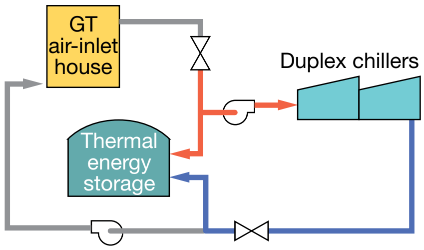
Project participants:
Vincent Hawkes, operations supervisor
Phil Norman, lead control-room operator
Plant operations personnel

1. Chiller coils were incorporated into the gas-turbine inlet air house (left)

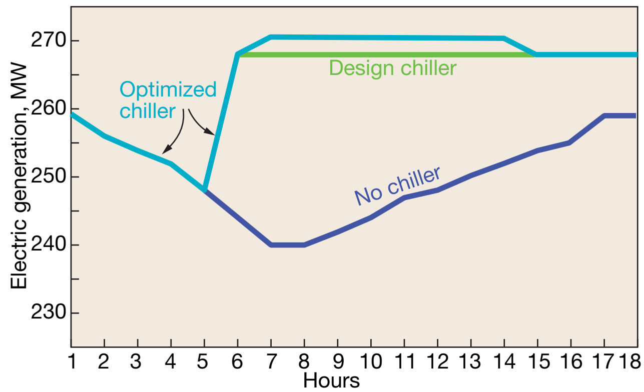
2. The chiller plant is rated at 3500 tons (above)



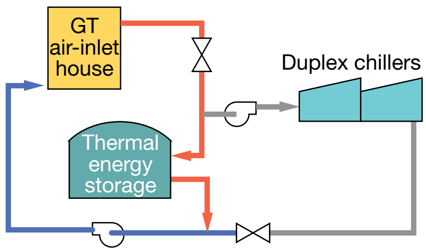
3. Partial-discharge mode of operation combines flows from the chillers and storage tank to cool inlet air



4. Thermal-storage recharge mode recharges tank to full cooling capacity



5. Optimized operating scheme does not run the chiller during peak periods (left)



6. Tank-only mode uses only fluid from the storage tank to cool the GT inlet air (right)

Membrane installation/removal tool reduces physical stress

Best Practices Award

Challenge. Change-out of RO membranes was a physical and time-demanding job. Johnson County's RO system has 28 membrane cylinders of nominal 22-ft length, each housing six 40-in.-long membranes (Figs 7, 8). This means 168 membranes must be pushed out and new or cleaned membranes pushed back in following a service run. The floor is normally wet with water and glycerin, making the working surface slippery.

Change-out of membranes required two employees pushing on the membrane train at one end of the tube and two employees on the opposite end to catch the fouled membranes; new or cleaned membranes were installed after the old ones were pushed out. Much of this push/catch effort required reaching above your head or standing on scaffolding.

Safety hazards exist when employees are pushing the used membranes with force, as well as when they are catching the ejected membranes. The chances of strain or sprain exist when the membrane is pushed and depending on the amount of pressure, can cause employee to over/under anticipate the outward pressure pushing the old membrane out. The challenge was to control this outward thrust, and apply adequate pressure making each insertion/ejection of membrane a controlled motion, without causing injury.

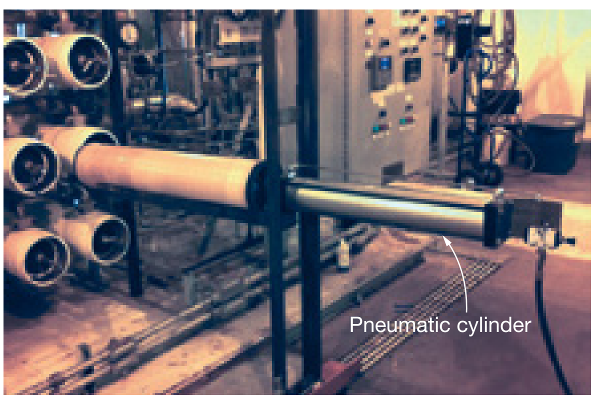
Solution. The maintenance team certainly has a working knowledge of what is involved in the changing of membranes. Not only are they "hands on" in the work involved, but also active in discussions at safety meetings striving to come up with ideas to maintain or improve the plant's safety record.

What began as a "what if" drawing on an office whiteboard, became a solution when plant personnel developed a portable air-operated piston and mounting device that aligns with each tube and pushes in the new membrane while pushing out the old membrane. With the new device in working order, the employees only need to load the new membrane on the alignment rack, activating the air piston and retrieving the exhausted membrane at the opposite end. When using the air-operated piston, you can load all six new membranes at once.

The vertical alignment rack is easily moved from row to row by fixed wheels attached at each end of the vertical unit. The piston also is easily moved up and down the vertical unit by inserting it into a machined slot. When not in use, the alignment rack and piston is moved to storage.

Results. The RO membrane installation/removal tooling system cuts two hours of labor off the time previously required for this job. The tool not only eliminates 95% of all physical demands, it has eliminated 95% of the safety hazards of sprains and strains associated with pushing or slipping on the wet floor.

Project participants:
Richard Connally
Michael Starks



7. Pneumatic cylinder pushes out RO membranes (above)

8. Vertical alignment rack is easily moved from row to row (right)

NV Energy Generation

Workforce design using Hoshin planning

Best of the Best Award

Challenge. For decades the electric-utility industry was stable, change slow to happen. This is no longer the case. Today, the industry is rapidly reshaping itself in response to political, economic, and regulatory pressures. Workforce changes also are on the fast track, with many employees retiring or leaving the industry. These senior personnel are being replaced by younger workers with different values and technical backgrounds. To respond effectively to the new paradigm, the industry needs an adaptable, flexible, and multi-skilled workforce.

Solution. NV Energy Generation has embraced the Hoshin process to develop a plan for realigning its workforce for the future. This process has these three primary characteristics:

- It involves fundamental change in the systems of the organization.
- It requires involvement by the entire organization.
- It is intended to bring the organization to the next level of performance.

The project, named Hoshin Workforce 2020, began with the development of nine strategies to guide the process. Example: Development of a fleet-wide process to manage external labor. Each strategy was led by a team tasked to develop an implementation plan. Team members represented the generation department, as well as human resources, supply chain, corporate communications, labor relations, and energy delivery. Nearly one-quarter of the employees within generation have been involved in the process, which has fundamentally changed how NV Energy Generation does business. Key breakthrough innovations include the following:

- A clear definition for core work—specifically, all the duties required for employees to produce electric power that cannot be obtained externally without degrading reliability, reducing quality, or increasing total long-term cost.
- A model that can be used to optimize and diversify staffing for each generation location.
- Use of competency-based assessments for employee development and retention.

The mission of the Workforce 2020 project is to (1) build well-trained,

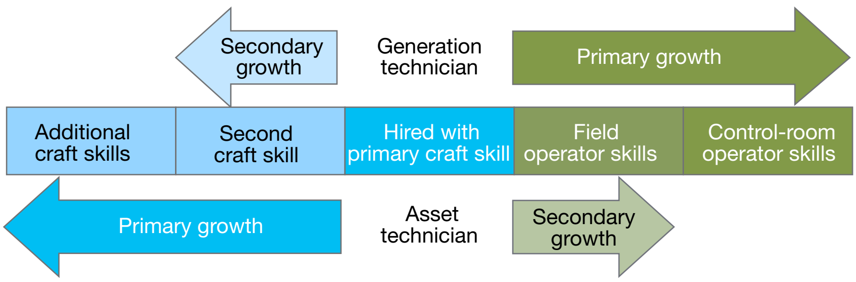
NV Energy Generation combined cycles

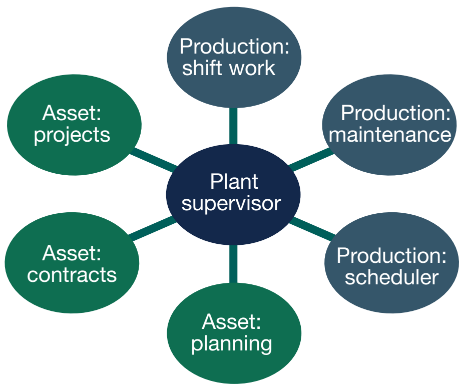
Edward W Clark, Harry Allen, Walter M Higgins, Silverhawk, Frank A Tracy, and Chuck Lenzie Generating Stations, and the Goodsprings Waste Heat Recovery Plant

Generation executive: Dariusz Rekowski

Director of generation engineering: Peter Steinbrenner

Regional plant directors: Wade Barcellos, Steve Page, and Tom Price





Benefits

- Coverage
- Succession planning
- Employee development
- Leadership development
- Entry-level leadership career path

1. An objective of Workforce 2020 is to reduce the number of worker classifications to two: generation technician and asset technician (above)

2. There is only one supervisor at each plant and that person can have any-one of six roles (left)

	Plant	Asset services department	Generation engineering	M&D center
Asset services organization	Plant asset manager Planners	Asset program manager Long-term contracts manager	Engineering manager	Reliability manager
Production organization	Plant production manager Schedulers		Plant engineers	Reliability manager
Engineering	Plant engineering manager/asset manager	Asset program manager	Engineering managers	

3. Plants need greater support from corporate groups

Tom Price, Dariusz Rekowski, and Peter Steinbrenner (l to r) skilled, motivated, and team-oriented employees, and (2) ensure employees will have the ability to successfully complete and lead tasks in many different capacities throughout the organization. By focusing on core work, the generation department has significantly reduced the number of job classifications, thereby improving the effectiveness of its training and recruiting programs.

Results. Work is ongoing and much remains to be done. Thus far, NV Energy Generation has developed three-year look-ahead (2015) workforce designs incorporating Hoshin core principles for each plant and for corporate services groups. Assuming the new workforce will be more efficient and non-core work will be outsourced, the number of employees is expected to shrink by about 7% over the next three years. Most plants already have begun defining what work is core and have prepared contracts for the non-core work.

NV Energy is negotiating with local bargaining unions to decrease the number of worker classifications to two positions: generation technician (focus on operations and support maintenance activities) and asset technician (focus on maintenance and support operation activities). Training programs are being developed for these two positions (Fig 1).

Traditional O&M managers are being replaced by production managers, with responsibility for day-to-day production and the management of bargaining-unit employees. Production managers focus only on core work. Plant-level asset managers are responsible for long-term performance of the physical facility, as well as core and non-core work, planning, and contractor oversight. There is only one supervisor at each plant and that person can take any of the following six roles: operations supervisor, maintenance supervisor, planning supervisor, scheduler, contracts supervisor, and project supervisor (Fig 2).

The plants will need greater support from corporate groups. The support required has been identified and the corporate groups are reorganizing to provide it (Fig 3). Two examples: a monitoring and diagnostic center and an asset management team. The M&D center will support plant operators with real-time diagnostics and provide reliability and performance engineering expertise. The asset management group will assist in monitoring plant performance and provide outage (overhaul) management services.

Project participants:
All NV Energy Generation employees

Seven NAES plants recognized for their Best Practices

Seven plants operated by NAES Corp, Issaquah, Wash, were recognized for their Best Practices at the CTOTF's™ Spring Turbine Users Conference, April 8, in Myrtle Beach, SC. These facilities received a total of 10 awards, including one Best of the Best, at the ninth annual presentation luncheon hosted by Goose Creek Systems Inc. NAES also was the most successful operator in 2011 and 2012.

The company, formed in 1980 by four utilities in the Northwest to provide project management services, today is the largest independent operations services provider in the industry with 84 combined cycles totaling nearly 40,000 MW under contract. It also manages 53 simple-cycle plants totaling more than 11,500 MW. A summary of the Best Practices NAES-operated plants share with the industry in this section follows:

Athens Generating Plant

New Athens Generating Co LLC

Plant personnel implemented an effective monitoring program to predict the reliability of non-redundant pumps utilizing real-time performance data, capacity modeling, vibration analysis, thermography, and daily operator inspection.

Dogwood Energy Facility

Dogwood Power Management LLC

Three awards:

The stainless steel seat in a 9-chrome stop-check valve serving the HP steam system cracked in service. Plant personnel evaluated alternative solutions, opting for inline repair because of its more competitive cost. Welding challenge was overcome by hiring a contractor with a water-cooled robotic welding rig capable of operating at the 450F preheat temperature required.

With personnel safety and operating reliability of paramount importance, plant personnel developed and implemented a comprehensive set of procedures to mitigate the wide array of risks associated with tornados, snow storms, and freezing temperatures.

Understanding the importance of employee advancement within the organization, plant personnel implemented a rotating training program where control-room operators receive hands-on expertise from power-plant management while sharing with the managers their technical knowledge to ensure a prepared, multi-skilled workforce.

Faribault Energy Park

Minnesota Municipal Power Agency

With prolonged subzero temperatures a prevalent risk to operating reliability, plant personnel developed and implemented a comprehensive freeze-protection program using detailed operator checklists and creative engineering. The results: Only one startup delay from a freeze-related issue in the last four years.

Granite Ridge Energy

Granite Ridge Energy LLC

Plant personnel developed a site-specific safety checklist and information card for chemical delivery drivers in order to familiarize them with the facility's rigorous safety requirements and proper protocol in case of an emergency.

Johnson County Generation Facility

Brazos Electric Cooperative Inc

Two awards:

Plant personnel utilized both intuition and data to create control logic and operational procedures for optimizing the facility's inlet chilling system, which effectively increases power output on the hottest summer days.

At some plants, manual change-out of RO membranes can be challenging to do injury-free on a consistent basis. Plant mechanics virtually eliminated the risk of muscle strain, and slipping on a wet deck, by developing a portable pneumatic device to load new membranes as old ones are pushed out the other end.

New Harquahala Generating Co

MachGen Holdings LLC

In investigating methods for performing work on wet cooling-tower fan assemblies more safely, plant staff tried multiple solutions—including many different tie-off points, temporary platforms, scaffolding, monorail, engineering cable system, etc. A permanent platform proved optimal.

TermoemCali

ContourGlobal Latam SA

Carryover of debris from murky river water fouled the condenser and CCW heat exchangers, primarily during startup. Issue was traced to plugged spray nozzles installed to clean inlet screens. A switch to well water from river water for the spray system during restart operations solved the problem.

Dave Ehler, Ed Mikulski, Darron Pruitt, Jeanette Carroll, Dean Blaha, and **Jim Carlton** (l to r)

Sevier

Collaboration, focus on constructability result in efficient design meeting challenging schedule

Best Practices Award

John Sevier Combined Cycle Plant

Tennessee Valley Authority

880-MW, gas-fired, 3 × 1 combined cycle located in Rogersville, Tenn

Plant manager: Terrell Slider

Challenge. The collaborative project team successfully overcame numerous design and logistical challenges, the primary one being schedule. The project was originally conceived by the owner to be a generating facility with a different configuration, at a different location, and with different major components from different manufacturers. The tight site impacted design parameters and necessitated modifications. TVA's engineer, URS Corp, was tasked to incorporate these changes without negatively impacting project schedule.

This project originated as a conversion of three existing simple-cycle gas turbine/generators (GTs) into a combined-cycle plant. Electric-system requirements dictated relocation of the project to a higher elevation and a different seismic zone and required dual-fuel GTs so the plant could use gas or distillate. The design had to allow operation in simple cycle, only without sharing ancillary equipment with the remaining combined-cycle equipment. Other design changes from the original included the source of makeup water and operation in simple- or combined-cycle modes.

The project required a complex environmental permit to incorporate the combined cycle into the existing permits for the adjacent coal plant. The National Pollutant Discharge Elimination System permit is shared with the active coal plant on the same site and was revised to include one additional outfall. The waste generation status also is shared with the active coal plant.

Jack Roddam, Bob Kirn, and **Zach Cowart** (l to r)

Solution. Previously, the design team had performed extensive engineering and procurement for the owner for the combined-cycle conversion project at the original location. That project was deferred and the engineering and material were redeployed for the current project. This project used state-of-the-art technology with a mix of new and gray-market components.

To ensure that the schedule and budget remained on track, the engineering team verified that equipment previously purchased would meet the new heat-balance parameters and incorporated new GTs into the design. The change in engines required additional design adjustments. Ultimately, the team was able to use 50% of the original project design and all of the equipment previously purchased, making efficient use of work already performed.

International collaboration was instrumental in overcoming design challenges. Engineering staff in Romania supported their US counterparts, working more than 40,000 man hours on this project. Sevier was one of the first deployments of Smart Plant P&ID and Smart Plant Instrumentation for the engineering team, allowing for efficient and timely interface between mechanical/piping and I&C team members.

Use of electronic eRooms for document management and collaboration allowed for timely transmittal of engineering drawings and documents, as well as the submission and subsequent return of shop drawings among parties. Communication among the home office, engineering, and field construction staff ensured design constructability and fast resolution of any issues.

Site constraints required innovative design approaches. Because of space constraints and constructability issues, a substantial number of electric cables had to be run above ground on tray racks, in lieu of using an underground duct bank or tunnel.

Successful accounting of air emissions between the coal and combined-cycle plants is complex because of the three HRSG stacks for normal operation and the three bypass stacks for simple-cycle service. The shared air permit utilizes a ledger to track when and where all emissions originate across the two plants.

Results. The owner/operator's mission is to be a leading provider of low-cost, cleaner energy by 2020, and the 880-MW John Sevier Combined Cycle Plant helps significantly in that regard. It operates at high efficiency, minimizes emissions, and offers optimal flexibility for meeting peak demand. The project, which finished a month early and $30 million under the original $820-million budget, is the owner/operator's lowest-cost, fossil-fired generating plant.

The project team successfully implemented all of the required modifications while meeting project milestones and holding costs well under budget. Result: The owner has a reliable generation source in northeast Tennessee.

The project uses three GE 7FA.04 dual-fuel GTs, the first of this generation to be tested and commissioned. The plant is also equipped with a Toshiba 400-MW steam turbine/generator and three Nooter/Eriksen heat-recovery steam generators. The latter have duct burners and catalyst systems for NO_x and CO emissions control. The plant also is equipped with bypass dampers and stacks to allow either simple- or combined-cycle operation. This capability was engineered into the plant to support the changing demand profile for the region and to provide maximum reliability.

Project participants:
Mike Hoy, senior manager, NUS construction projects, TVA
Bill Lam, URS
Bob Schad, URS
Bob Romanelli, URS
Tom Brown, URS
Rob Chiavaro, URS
John Moore, URS

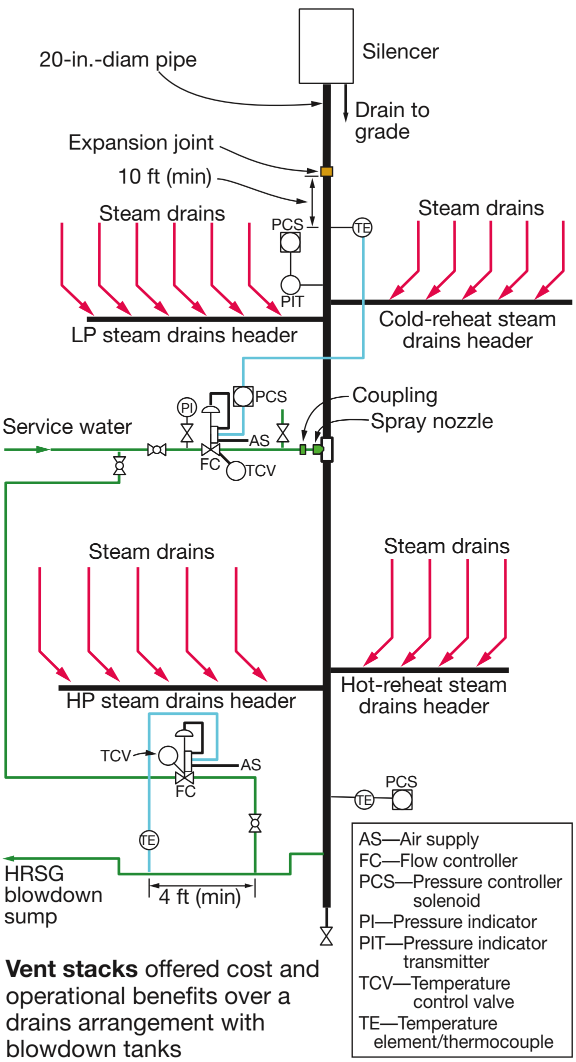
Adapting vent stack design to handle flashing of process-steam drains

Best Practices Award

Challenge. Headers serving steam systems operating at four different pressures must be drained to prevent condensate from entering the steam turbine during startup, shutdown, and/or other modes of operation at this combined-cycle plant. Piping for each steam system is routed in a pipe rack that extends more than 450 ft.

Low-point drains located strategically along the piping runs collect condensate in drip pots. Each drip pot relies on an air-operated, fail-closed drain valve controlled by either a thermocouple or level switch to discharge condensate. A total of 72 drain valves must be organized and controlled to perform this task properly.

Drain tanks typically are used for collection of these drains. But on this project, vent stacks were specified in lieu of tanks. The challenge for engineers was that the design of the vent stacks did not provide adequate controls and the necessary heat transfer to allow their proper operation.



Vent stacks offered cost and operational benefits over a drains arrangement with blowdown tanks

Solution. Three locations along the pipe rack were identified to support the vent stacks and allow the drains to discharge the flashing steam and water safely. The various drains, grouped by steam pressure, were connected to manifolds, which discharged to vent stacks sized to accommodate the expected steam release. Steam passes through a silencer before discharge into the atmosphere (figure).

Each vent stack, constructed from heavy-wall alloy-grade pipe with a cap at one end and a silencer and expansion joint on the other, was supported to allow proper thermal growth as steam was vented. To minimize the length of each drain pipe, drains were routed to the closest vent stack. Thus each vent stack did not contain the same quantity of drains nor release the same quantity of steam/condensate.

During plant startup, engineers determined that the pressure within the vent stack exceeded the design pressure of the system, and that there was insufficient heat transfer to lower the exhaust steam temperature to an acceptable level, even though the service-water temperature control valve was wide open.

To manage temperature and pressure within the vent stack, the system was modified to introduce service water through a spray nozzle, which created a fine mist into the venting steam to help reduce the temperature within the stack as it reaches the design limits of system. A pressure transmitter installed a sufficient distance from the inlet to the silencer monitors the internal pressure and controls the quantity of drains discharging into the vent stack should the pressure approach expansion-joint design limits.

Any condensed steam and excess spray water would be routed from the vent stack and collected in a sump for use as cooling-tower makeup. Additional spray water and a thermocouple are connected to the drain from the vent stack, thereby controlling the temperature of hot water/steam discharging to the sump, protecting the sump pumps from damage.

Results. Normally, the steam system drains are discharged to blowdown tanks—or, in this case, vent stacks—and the drains are kept open during the startup for a substantial period of time until the piping is heated and the steam shows signs of superheat. This requires over-sizing of equipment (blowdown vessels, silencers, supports) in an effort to discharge steam and water, which also results in the loss of large quantities of steam (that is, more make up required).

For this project, use of piping as the vessel to discharge the flashing steam and condensate was more economical than designing and fabricating a blowdown vessel. This approach also took less space and required no foundation.

By monitoring both the temperature of the steam being discharged and the pressure within the vent stack, the operator is able to control the quantity of steam being discharged and stay within the design parameters of the equipment. This minimizes the loss of steam, shortens the duration to generate steam, and helps reduce capital cost.

Project participants:
Mike Hoy, senior manager, NUS construction projects, TVA
Robert V Chiavaro, URS

Voltage-class evaluation results improve cost-effective performance

Best Practices Award

Challenge. Standard industry practice suggests that 200-hp motors are the breakpoint between low- and medium-voltage service to mitigate voltage-drop concerns. The cooling-tower fan motor rating for each of the 12 cells at John Sevier Combined Cycle Plant was 200 hp. Cooling-tower vendors typically would suggest 480-V motors for these fans.

However, Sevier was designed with two circulating-water pumps powered by 4.16-kV motors supplied from the same electrical room. Given the high 480-V demand and the proximity of 4.16-kV power, the project team evaluated use of 4.16-kV motors for the fans.

Solution. URS estimated the cost of each voltage-class configuration on an equipment and labor basis only. The engineering analysis and resulting study showed that the medium-voltage configuration would be preferred from both an operational and capital-cost standpoint. Therefore, medium-voltage motors were recommended.

Employing the medium-voltage system offered several advantages. Overall, there are fewer cables to be installed, less equipment to be maintained, and the 4160-480-V transformers were eliminated. One medium-voltage motor control center was provided in lieu of an additional low-voltage double-ended power center.

Results. Based on the evaluation findings, medium-voltage motors were installed to drive the cooling-tower fans. The power distribution system meets the owner's performance requirements and reduces costs. The successful implementation of this best practice suggests that when there are multiple loads of 200-250-hp motors, evaluation of the voltage selection is prudent and a medium-voltage system may be more cost-effective; plus, it offers a more robust design.

Project participants:
Mike Hoy, senior manager, NUS construction projects, TVA
Robert Schad, supervising electrical engineer, URS

Lea

Ammonia-tank level monitoring contributes to high plant availability

Best Practices Award

Challenge. Lea Power Partners LLC uses one 9000-gal aqueous ammonia tank for control of NO_x emissions from two M501F gas turbines. During typical operation, the ammonia tank is refilled every four or five days, when the tank level is low enough to receive a full shipment of ammonia (approximately 6000 gal).

Frequent calls to the ammonia supplier were required in order to communicate the tank level and projected refill date and time. If the call to refill the tank were made too early, the potential existed to have inadequate space in the tank to offload the entire shipment. Conversely, if the call to dispatch a truck were made too late, the plant would need to make provisions with a third party to add totes of ammonia to the tank in order to avoid a forced de-rate or shutdown.

Solution. Working with the local Airgas distributor, the plant installed a tank level transmitter that communicates real-time ammonia level with the delivery dispatcher (Fig 1). This transmitter also communicates directly to the plant DCS system, allowing the system operator to actively monitor and trend ammonia usage and tank levels to accurately schedule deliveries. Efficient scheduling of bulk ammonia deliveries eliminates the unnecessary risks to personnel of ammonia-tote transfer.

Results. After installation of the remote tank level transmitter, the plant noticed immediate efficiency of ammonia deliveries. All guesswork has been removed, eliminating last minute scheduling of ammonia deliveries while saving the plant from paying expedited trucking costs. Possible forced de-rates or shutdowns caused by ammonia shortages have also been eliminated. Plant personnel are no longer required to handle totes of ammonia, eliminating risks associated with their storage and transfer.

Project participants:
John Texter
Roger Schnabel
Adam Rogge
Richard Shaw
Roger Henderson
Tom Motley
Todd Witwer

Lea Power Partners LLC

Owned by FREIF North American Power I LLC
Operated by Consolidated Asset Management Services

604-MW, gas-fired, 2 x 1 combined cycle located in Hobbs, NM

Plant manager: Roger Schnabel

1. Ammonia level transmitter lets dispatcher know when to schedule a delivery

Christopher Sargent and **Roger Schnabel** (l to r)

Hydrogen system modification improves safety, balance sheet

Best Practices Award

Challenge. The hydrogen supply system for cooling the generator driven by Lea's steam turbine was commissioned as a 20-station compressed-gas cylinder rack (Fig 2); it required an additional 20 cylinders for system makeup. As designed, the system required manual intervention by a plant operator to replace each exhausted cylinder—a daily task. Frequent manipulation of compressed-gas cylinders exposed plant personnel to the risks of back injury associated with lifting.

The additional cylinders necessary to maintain system makeup also caused the facility to incur high cylinder rental/delivery fees. Plant personnel began to explore the options available to reduce the risks associated with cylinder handling.

Solution. Plant personnel worked with the local Airgas distributor to install a low-pressure bulk hydrogen storage tank to work in parallel with the existing compressed cylinder distribution system (Fig 3). The bulk hydrogen tank piping was coupled to the existing cylinder rack piping to eliminate the need for daily cylinder manipulation and handling. In addition to eliminating the need for daily cylinder management, the bulk tank replaces the weekly hydrogen cylinder delivery with a monthly bulk hydrogen delivery. The existing compressed-gas cylinder racks are still used as a backup system.

Results. After the hydrogen bulk tank installation project was complete, the facility began to see immediate advantages to the new arrangement. Operator man-hours required to receive hydrogen delivery has been reduced by 70%, while the operator man-hours required to handle full compressed-gas cylinders between deliveries have been eliminated. An added advantage to the bulk hydrogen tank system is during scheduled generator purges; additional hydrogen cylinders are no longer needed, eliminating additional cylinder manipulation by plant personnel.

The bulk hydrogen tank also saved money—$27,600 in the first year of the project. With a project cost of $31,900, the payback is a little over one year; annual savings will continue through the life of the facility.

Project participants:

Roger Schnabel	Tom Motley
John Texter	Carlos Sanchez
Adam Rogge	Todd Witwer

Wastewater reclamation project produces big cost savings

Best Practices Award

Challenge. Although operating within design specifications since COD in 2008, Lea Power Partners LLC had been burdened with excessive wastewater disposal costs. The existing treatment plant was unable to process an adequate volume of water to manage evaporation pond levels, forcing the plant to contract trucks to haul wastewater offsite to an approved disposal site.

The cost of hauling and offsite disposal was much greater than that anticipated for wastewater management. The added cost of operating and maintaining wastewater equipment also accounted for more man-hours than initially anticipated. Plant personnel began to explore different options available to reduce the costs and time needed to operate the plant wastewater treatment stream effectively.

Solution. Working with the state department of water quality, the plant applied for and was granted a land-application discharge permit. It allows the plant to discharge wastewater to evaporation ponds, which act as holding tanks, then permits wastewater reclamation by center pivot irrigation.

Coordinating with a local land owner adjacent to the plant property, a center pivot was installed to provide beneficial-use irrigation for 80 acres of farm land. Plant wastewater is now used to supplement irrigation water to raise various beneficial crops in the local semi-arid climate. Operation of the center pivot is controlled through the plant control room through coordination with the local land owner.

Results. After installation of the center pivot, the facility began to see immediate results. The 2012 budget for wastewater treatment was reduced to 5% of the 2011 budget. The project cost for the center pivot irrigation system was returned within five months of use. While the plant raw water use did not increase in 2012, chemical and maintenance costs towards the wastewater treatment facility have been almost eliminated, providing additional dramatic chemical cost savings and increased operator availability for other maintenance tasks.

Project participants:

John Texter	Todd Witwer
Roger Schnabel	Carlos Sanchez
Adam Rogge	Richard Shaw
Tom Motley	

2. Compressed-gas cylinder rack with 20 stations supplied hydrogen for cooling the generator coupled to the steam turbine (left)

3. Bulk storage tank reduced the cost of hydrogen significantly (above)

Control system mods enable 10-min starts; increase reliability, flexibility

Best Practices Award

Holden Power Plant

Associated Electric Cooperative Inc

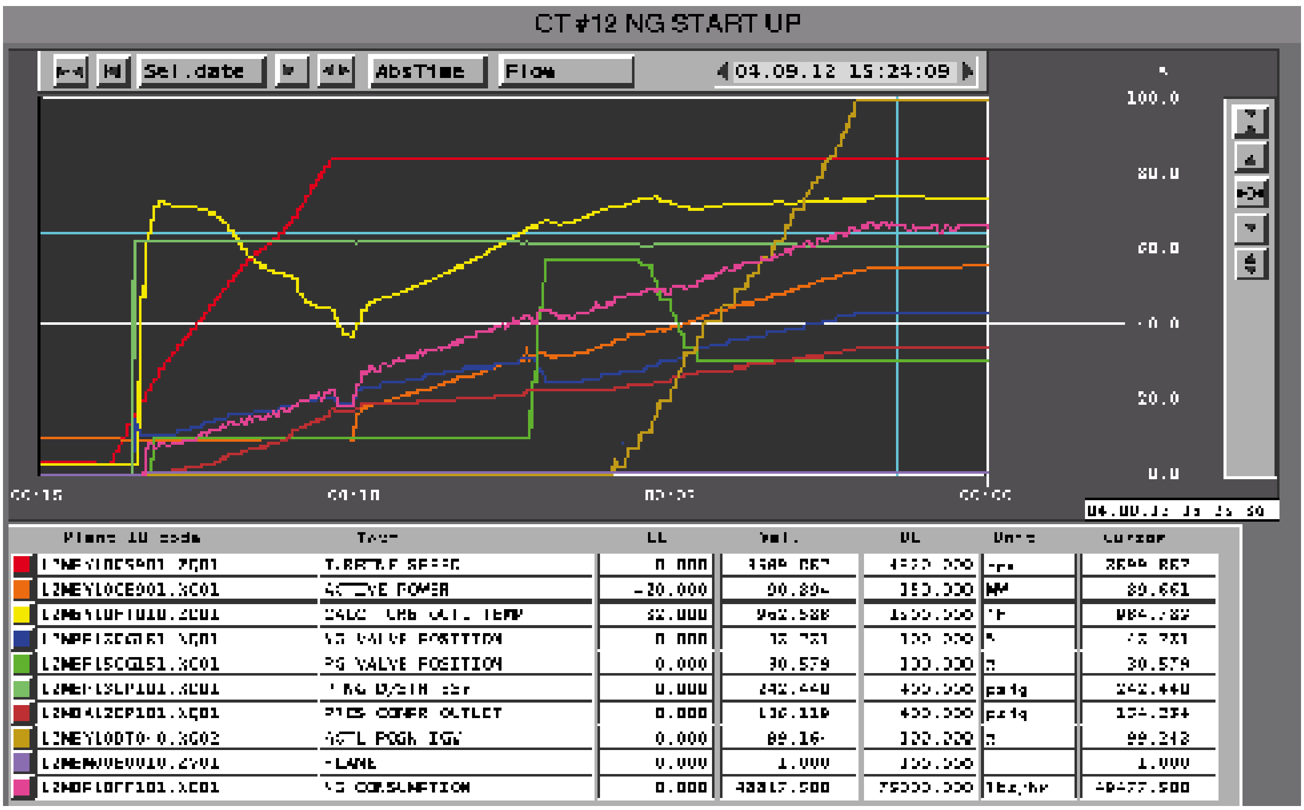
321-MW, dual-fuel, simple-cycle peaking facility located in Holden, Mo

Manager of gas plant operations: Gabe Fleck

Challenge. The primary business challenge motivating Holden Power Plant's Fast Start Project was the transition from 300 MW of wind at the beginning of 2012 to 600 MW of wind at the beginning of 2013, with another 150 MW under contract for the future. This addition of wind requires increased flexibility of other assets to address the variable power supply of the renewable resource.

Solution. AECI hired Siemens Energy Inc to modify startup logic and controls, as well as to re-tune to improve the full-load start time. Details of the logic changes and implementation follow:

- Modified logic for the air dampers and fuel-gas isolation valve to allow them to open earlier in the startup sequence.
- Modified logic for the fuel-gas isolation valve to allow proper opening and closing in the event of a trip on startup.
- Modified logic for the ignition gas valves to allow optimized operation.
- Modified logic to allow the operator to select fast or normal start.
- Added logic to allow the fast-start load gradient to be operator-selectable from 10 to 27 MW. The original load gradient was 10 MW/min; fast start uses the 27-MW/min loading.
- Modified logic to allow fast-start selection through the RTU interface.
- Modified IGV logic to allow successful premix operation through the faster transfer time.
- Modified pilot-gas-valve logic to enhance flame stability.
- Fast-start load gradient kicks out



1. Sept 4, 2012: A normal start on Unit 12 to 90 MW, loading at 10 MW/min, took 5 min 38 sec until breaker close and 13 min 54 sec until the outlet temperature controller was active once the load set point is reached or when outlet temperature control (OTC) is achieved.

- Adjusted startup parameters to make the startup curve more linear from 150 to 3600 rpm.

Results. Before the fast-start modification, the Holden units were AECI's fastest starting units at 15 minutes from beginning of start to full load. Full-load start time was reduced by an average of 6 minutes to an approximate 9-min full-load start time. More specifically:

Unit 11: 8 min 59 sec *(6 min 17 sec improvement).*

Unit 12: 8 min 51 sec *(5 min 3 sec improvement).* See Figs 1, 2.

Unit 13: 9 min 19 sec *(6 min 45 sec improvement).*

Mark Treat

Key project highlights/facts included the following:

- The Fast Start Project began Sept 26, 2012 and was completed on October 5. It was a team effort among OEM Siemens, Holden personnel, and Associated Electric Cooperative Inc's headquarters engineering staff.
- Base load for fast-start testing was 103 MW; normal ramp rate was 10 MW/min, fast-start rate 27 MW/min. The ramp rate is selectable by system operators via the RTU interface.
- The fast-ramp rate applies only to fuel-gas starts; ramp rate on fuel oil remains unchanged at 10 MW/min.
- Faster start times were achieved only through logic and tuning changes. There were no physical modifications to the equipment.
- The first fast start was called for less than 24 hours after project completion; expectations were met.
- From commissioning in October 2012 through January 2013 there were a total of 22 fast starts on the three units arranged for that capability; all were successful. There also were 25 normal starts.
- Late last January, all three units were called on to fast-start concurrently following the trip of a coal-fired unit. Expectations were met.

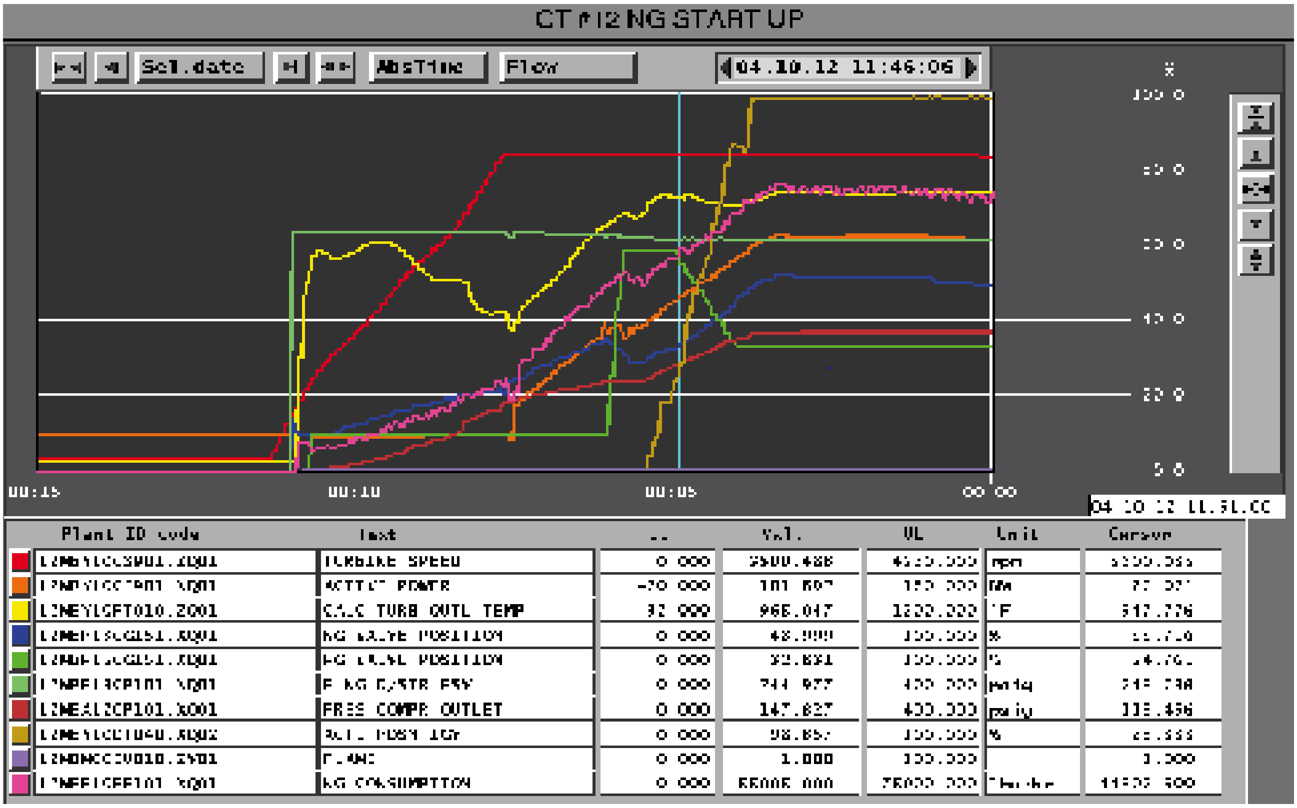
Disturbance control standards. Faster Holden starts allow AECI to better comply with NERC Standards for DCS events. BAL-002 requires the utility to provide reserves within 15 minutes following a DCS event. Holden often is counted as AECI's non-spinning contingency reserves. A faster start time allows for better compliance with this standard.

Control performance standards. Faster Holden starts provide better compliance with BAL-001 CPS. A newly proposed revision of BAL-001 and a field trial, in which AECI is participating, requires correction of negative Area Control Error (ACE, under generation) within 30 minutes during periods of low frequency. A faster Holden start time allows for other options to be exercised first to try to mitigate a BAAL (Balancing Authority ACE Limit) event. This allows for more time before Holden units have to be started, actually reducing the number of Holden starts and keeping costs low.

Renewables integration. Faster Holden starts give AECI more megawatts faster helping it mitigate the risks with wind. With more wind generation coming on line, the utility had to address the system responsiveness. Several alternatives were considered on the basis of cost—from constructing new units to modifying other units to start in less than 10 minutes. The economic solution was arranging for fast-start capability at Holden.

Project participants:

Joel Wilhite, senior CT specialist
David Shirley, senior CT specialist
Rod Rupert, controls engineer
Steve Combs, controls engineer
Mark Treat, principal engineer



2. Oct 4, 2012: A fast start on Unit 12 to 103 MW, loading at 27 MW/min, took 4 min 40 sec until breaker close and 8 min 51 sec until the outlet temperature controller was active

Dogwood

Inline repair saves 9-chrome HP stop/check valve

Best Practices Award

Dogwood Energy Facility

Owned by Dogwood Power Management LLC
Operated by NAES Corp

650-MW, gas-fired, 2 x 1 combined cycle located in Pleasant Hill, Mo

Plant manager: Pete Lepage

Dean Blaha and **Darron Pruitt** (l to r)

Challenge. Dogwood Energy Facility was experiencing internal leak-by on a 12-in. stop/check valve in the high-pressure (HP) steam system. The valve was opened with the expectation of needing to perform valve plug and disc machining and lapping to resolve the leak-by issue.

However, on disassembly, personnel discovered that the valve seat had cracked (Fig 1). The failure mechanism was differential expansion—that is, the Type-316 stainless steel seat and 9-chrome valve body were growing and contracting at different rates. The valve was reassembled and run as found until a suitable plan could be established to facilitate the repairs.

Solution. The plant considered three ways to deal with the issue, each with its benefits and detractions:

- Repair the valve according to the valve manufacturer's recommendation.
- Replace the valve with a new valve.
- Perform an inline repair.

The valve manufacturer's recommendation for repair involved cutting the valve out of the pipe and lowering it to the ground, through structure, from an elevation of 85 ft. The valve would then be shipped to the repair facility; a minimum of eight days was required for proper machining and heat treatment. The valve would then be returned to the site, lifted back up into position, and welded back into the steam line.

A couple of logistical challenges: Cutting the valve out of the line and welding it back into place presented issues, but they were not insurmountable. Examples: Would it be better to use a crane to lower and lift the valve or would a tugger be more cost effective and perform better given its location? (2) There is piping and structure overhead, but maybe it would be better to raise the valve out of the structure, then swing to an open area and lower the valve to the ground.

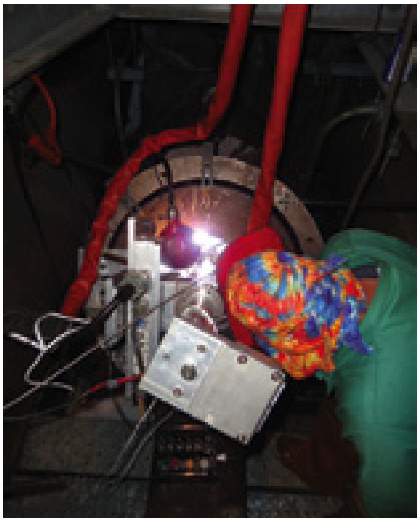
Next, when the valve was back in place it was important to maintain proper piping alignment to avoid creating damaging stresses. Alignment dogs would have to be welded to the piping and valve. To do this properly would require extensive heat treatment since the valve and piping are both 9-chrome material. Lastly, welding the valve back in the steam line would require the proper weld procedure for 9-chrome material. The estimated duration to perform this repair was 20 days at a total cost of about $165K.

1. Valve seat of Type-316 stainless steel was found cracked

The next option was to replace the valve with a new one. The advantage of doing this was that the valve could be delivered to the site before the outage began so that as soon as the original valve was cut out and lowered to the ground, the new valve would be lifted into place and welded in the pipeline. With the exception of the duration of time needed for shipping the valve to a repair facility and shop repairs, this option posed the same problems as the manufacturer's repair recommendation.

Bids for a new valve were obtained from three different manufacturers; the average cost was $208K. Field work was estimated at 10 to 12 days, including the time to perform the work and allow for proper pre- and post-weld heat treatment.

The last option on the table was to perform the repairs with the valve inline. There were inherent advantages to performing the work by this method. However, there was one major challenge: Finding a company that could do the work in a satisfactory manner. The inherent difficulty with the inline repair alternative was that the existing seat would have to be removed and welded back in through the throat of the valve




2, 3. Seat pocket weld build-up in progress at left; finished at right

4. Seat is welded into the repaired seat pocket

as opposed to the back side of the seat in the steam line.

Machining the seat out should not pose a problem, but once again, procedures to weld the seat back in would require proper pre- and post-weld heat treatment. This would mean holding the valve at approximately 450F while the seat was welded into place. The seat pocket is located about 32 in. down inside of the valve throat. This is beyond—or at the limit of—an arm's length at shoulder depth, which would preclude the technician from being able to look down inside of the valve while welding.

Even if the seat pocket were reachable, the technician's hand and arm would be exposed to a temperature of 450F while welding. Robotic welding would be difficult because of the temperature environment as well. The first contractors consulted all recommended welding at the end of a stick and using mirrors.

After an exhaustive search, plant personnel found a repair company that had developed a water-cooled system for a robotic arm capable of welding and machining at the temperature required to do the work. The work was estimated at 11 to 12 days working around the clock; the cost would be approximately $188K.

The plant did not have an outage period scheduled for 2012 which would allow for 20+ days of downtime, so anything beyond a scheduled 10-day outage would make the plant unavailable for commercial operation. Cost, impact to the system, and timeline all pointed to performing the inline repair.

Once the valve was opened and the seat was machined out, it was determined that the seat pocket would need to be built up by weld repair, and then machined back to within spec (Figs 2, 3). After that was done, the seat could be inserted and welded in (Fig 4). The job went according to plan with exceptional results.

To minimize the chance of future failure of the seat from differential expansion, the valve manufacturer was consulted and said it was acceptable to replace the stainless seat with one of F91. This would match the material composition of the valve body.

Results. The project came in on time and well under budget with a final dollar amount of approximately $160K. There was zero impact to the schedule and system because the valve remained inline, thus minimizing the problems associated with line spring and subsequent piping alignment.

The piping was plugged using FME (foreign material exclusion) devices, and upstream and downstream borescope inspections were conducted prior to valve reassembly. Finally, the repair was completed within the scheduled outage and no revenue was lost because of unavailability.

Project participant:
Glenn Brons, maintenance coordinator

Management training for day-shift O&M technicians

Best Practices Award

Challenge. Develop a workforce capable of successfully assuming managerial roles.

Solution. Create a program to advance existing employees through hands-on exposure. In late 2012, Dogwood Energy Facility launched its "Day Shift O&M Technician Program" (DSOM) which uses a staff of five O&M Technician-A/Control Room Operators (CROs) on a five-week rotating basis. Here's how it works: One CRO moves to a position equivalent to that of an operations coordinator for five weeks. At the end of the period, the CRO resumes a standard shift, allowing the next CRO in the rotation to enter the DSMO position.

The core objective of the program is to maximize employee development by allowing upper-level operations staff to gain experience in the managerial aspects of power generation while also providing management with direct access to operator-level activities and knowledge for the purposes of planning and reliability.

Duties of the DSOM as described in the "Plant Policies and Procedures Manual" covers a wide array of responsibilities, such as supervising the work of the operations department, developing and drafting lesson plans, conducting training, providing managers with technical expertise and knowledge, etc. The program also acts as a "tryout period" allowing managerial staff to critique the abilities, desire, and potential for development of each participating CRO.

It also allows the participants to experience day-to-day activities on a managerial level so they can determine if the "next step" is appropriate for them. Highly knowledgeable and proficient employees with the desire to advance will be well prepared to step into managerial roles with the least amount of transitional stress, thereby increasing the likelihood of success in their new roles.

There are several expected benefits to what is hoped will be a pilot program for the company. First, in light of the expected increase in natural-gas-fired

1. CRO's 32 Degree Action Log

When the plant is shut down in cold weather, the CRO for each shift must run through a special checklist to assure critical systems and equipment are not experiencing freeze-up issues. A log is completed once per shift when the ambient temperature is between 21F and 31F, twice per shift when the temperature is 20F and below. Note that one boiler-feed pump per unit and one condensate pump are kept in operation during cold-weather shutdowns.

The equipment and systems monitored are listed below along with the prescribed actions. If freeze-up is suspected, the CRO must enter on the log the "corrective action taken" and the time of that action, and initial.

System or equipment	Action
Kettle boiler	Verify operability of level transmitters. Open kettle-boiler automatic drain if pressure and level will allow. Verify transmitter's response
Condensate pump	Alternate condensate pumps. Verify minimum-flow recirc transmitter response to changes in min-flow recirc-valve position
HP startup vent	Open and close
IP startup vent	Open and close
LP startup vent	Open and close
Boiler feed pump	Alternate boiler feed pumps. Verify minimum-flow recirc transmitter response to changes in min-flow recirc-valve position
HP drum	Open intermittent blowdown valve. Verify drum-level transmitter response. Check all three transmitters
HP drum	Cycle continuous blowdown valve
HP drum	Fill drum and verify drum-level transmitter response. Check all three transmitters
HP drum	Verify feedwater-flow transmitter response
IP drum	Open intermittent blowdown valve. Verify drum-level transmitter response. Check all three transmitters
IP drum	Cycle continuous blowdown valve
IP drum	Fill drum and verify drum-level transmitter response. Check all three transmitters
IP drum	Verify feedwater-flow transmitter response
LP drum	Open intermittent blowdown valve. Verify drum-level transmitter response. Check all three transmitters
LP drum	Fill drum and verify drum-level transmitter response. Check all three transmitters
LP drum	Verify feedwater-flow transmitter response
Circulating water pumps	Open and close discharge valves
Cooling tower	Open riser bypass valves and verify that no water is going over fill. Close riser isolation valves are required
HP steam	Open steam bypass attemperator feedwater control valve 15% to maintain flow. Downstream drain lines should be opened to facilitate draining
HRH steam	Monitor hot-reheat steam attemperator temperature for freeze issues
All steam systems	Cycle all motor-operated steam-system drain valves
HP steam	Force open the steam attemperator and flow water; be sure to open appropriate steam drains

power generation, the O&M provider for the facility will be well positioned to continue to offer the highest level of experience and support to its customers.

Secondly, by engaging in employee development and promoting from within the existing pool of talent, the plant operator will be creating a base of loyal employees who will be more likely to devote their careers to the company.

Given the challenges faced by the industry in the form of an aging and retiring work force it is crucial that companies within the industry create the means for retaining talented individuals. The financial benefit of retaining talent and limiting turnover is well worth the effort of the program.

Results. To date, the DSOM program has completed one full rotation of all five CROs. The consensus among the participants is that the program is creating positive results. All feel they have gained insight into managerial activities and knowledge that was not available to them prior to the program. Continued success is expected as the program advances.

Project participants:
Dwight Beatty, O&M manager
Jeff Hamrick, CRO

2. B Operator's 32 Degree Action Log

When the plant is shut down in cold weather, the B Operator for each shift must run through a special checklist to assure critical systems and equipment are not experiencing freeze-up issues. A log is completed once per shift when the ambient temperature is between 21F and 31F, twice per shift when the temperature is 20F and below.

The equipment and systems monitored are listed below along with the prescribed actions. If freeze-up is suspected, the operator must enter on the log the "corrective action taken" and the time of that action, and initial.

System or equipment	Action
HRSG 1 and 2, eastside drains	Check every drain for flow. When unit is offline and pressure drops to 200 psig, crack each drain open to ensure water flow
HRSG 1 and 2	Check kettle-boiler drains to ensure water is flowing
HP steam	Drain transmitter high and low legs following a unit shutdown
HRH steam	Drain transmitter high and low legs following a unit shutdown
LP steam	Drain transmitter high and low legs following a unit shutdown
Units 1 and 2	Condensate to LP drain hose on the feedwater deck: Make sure the hose is draining; if not, bring it inside to thaw out.
Portable heaters	Refuel portable heaters as necessary

Extreme-weather preparedness increases availability

Best Practices Award

Challenge. Dogwood Energy Facility is a 650-MW combined-cycle plant located just outside of Kansas City. Its location makes it susceptible to a wide range of weather-related problems, exacerbated by having most of the plant located outdoors.

Since the plant is an independent power producer and operated by a staff of only 24, making sure the plant is ready to run at any time is very important. The biggest obstacle to availability is that the plant has to deal with the freezing temperatures, snow storms, and tornado season.

Solution. As a part of the site's continuous improvement culture, personnel are encouraged to help identify issues along with determining the best workable solutions. As a result the plant has come up with several program elements that keep its availability high. The following are the problems the plant has had to face and the solutions that have been put into practice to mitigate them.

Freezing temperatures. The following is a list of action plans and preventive-maintenance techniques to prepare for winter weather:

- CRO's 32 Degree Action Log. This identifies equipment and systems that the CRO must check in cold weather to guard against freeze-up issues. Temperatures between 21F and 32F require the actions once per shift while temperatures 20 degrees and below require the actions twice per shift (Sidebar 1).
- B Operator's 32 Degree Action Log. Requires the outside operator to verify certain drains and transmitters are not frozen under the same temperature requirements as stated above. They also make sure that any portable heaters are working and have plenty of fuel (Sidebar 2).
- Operations personnel verify through rounds that all heat-trace panels come on and are working properly below 38F.
- A September PM in the CMMS system assures that all heat tracing is working. If not, a work order is

3. Snowstorm checklist

Three days ahead:

Verify inventory of chemicals and gases (hydrogen, ammonia, propane, etc) and place "emergency" order if necessary.

Two days ahead:

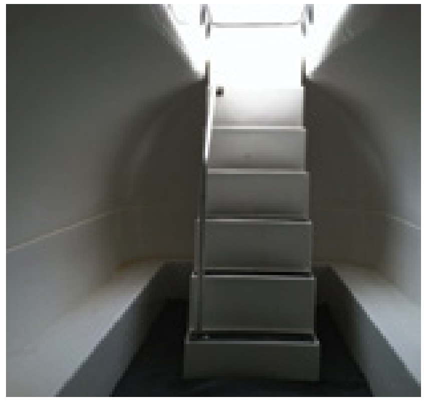
1. Verify food supplies against the inventory list; purchase if necessary.
2. Verify sufficient clean sleeping supplies for all employees expected to stay (air mattresses, cots, sheets, pillows, blankets, etc).
3. Verify availability of snow shovels and hand-held salt spreaders.
4. Have snow blowers moved to warehouse and tested.

One day ahead:

1. Notify oncoming shift personnel of expected hazardous weather. Tell them to be prepared to stay onsite and to bring all necessary food, clothing, and personal hygiene items.
2. Verify snow plow on the company truck works.
3. Verify salt spreader on the company truck works.
4. Verify chains are available for the company truck (if necessary).
5. Make room in warehouses and water treatment area for vehicle parking.
6. Fill all onsite water tanks to maximum level (service water and demin water).

During and immediately following the storm:

1. Monitor weather conditions on the Internet.
2. Stay as warm and as dry as possible. Use laundry equipment as necessary to keep clothes dry.
3. Try to stay ahead of snow buildup with snow plows, shovels, and blowers.
4. Spread deicer on sidewalks, roadways, and walking areas.
5. If stairs and walkways get icy, don't use them.
6. Get rest when off-shift to be alert for on-shift period.
7. Plow snow away from the power block, and/or near storm drains, to prevent melt/refreeze conditions from creating hazards on asphalt.
8. Do not perform functions that are dangerous to personnel or plant.
9. If plant makeup water supply is lost, conserve onsite water by reducing cooling-tower blowdown (cycle-up the cooling tower).
10. Ensure plant spill kits and emergency equipment (such as fire hydrants) are accessible.



5, 6. Tornado shelter entrance is at top, inside view at bottom

written and the system repaired.

- Another September PM: Fill all necessary transmitter legs with glycol.

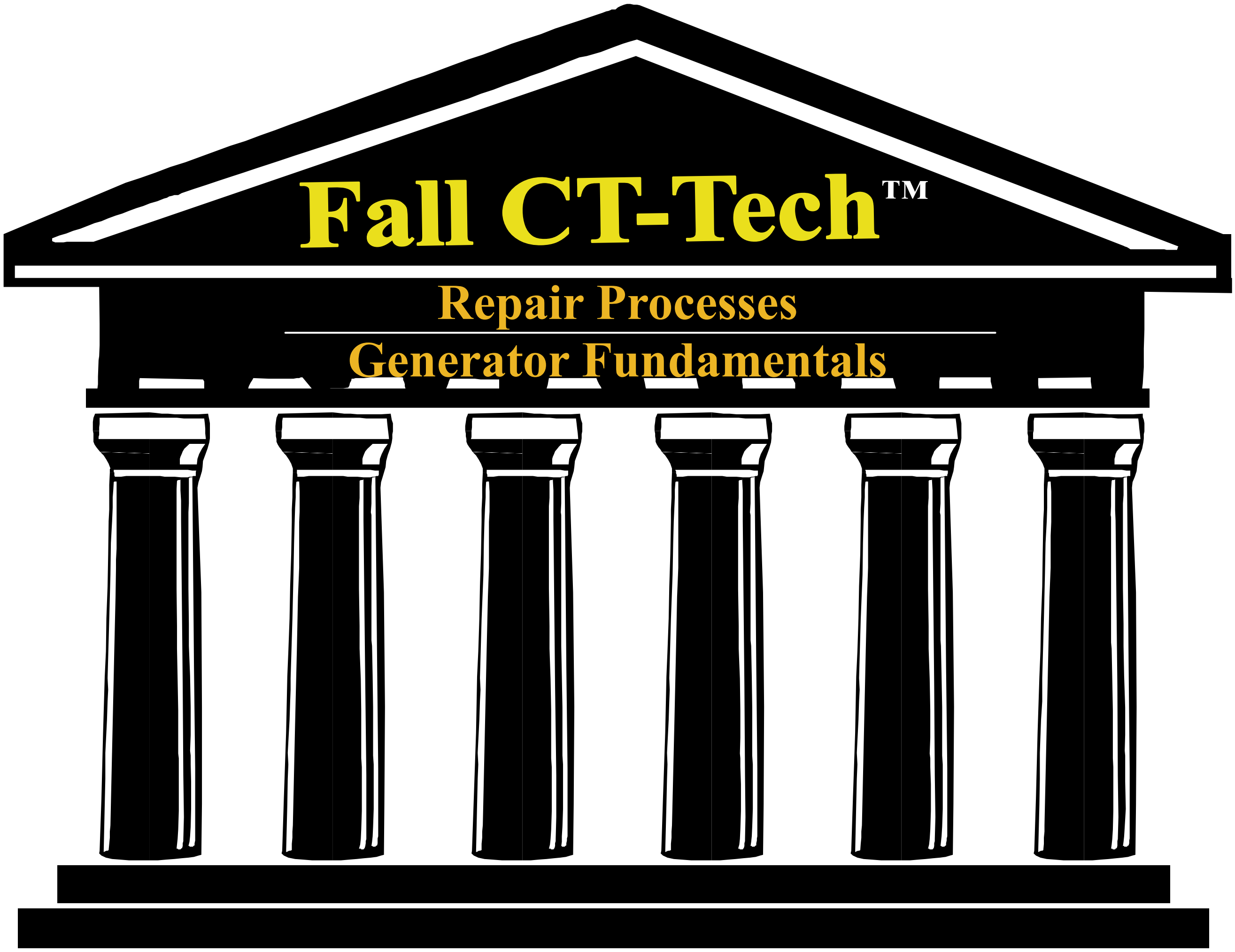
Snow storms. A comprehensive checklist was developed to help systematically prepare for and respond to snow storms where getting certain equipment and supplies to the plant might be impeded because of the weather event (Sidebar 3).

Tornados. Since the plant resides in an area known to have a high rate of tornadic activity, the facility decided to invest in storm shelters that would help protect staff and any contractors onsite (Figs 5, 6). Two storm shelters capable of accommodating 20 persons each were installed. One is located behind the main building and the other is by the contractor trailers. These shelters meet the following requirements:

- FEMA Publication 320
- ICC 500-2008, "ICC/NSSA Standard for Design and Construction of Storm Shelters."
- ASTM E 1886-05, "Standard Test Method for Protective System Impacted by Missiles."
- NPCTS, "National Performance Criteria for Tornado Shelters."

Results. Because the plant is an IPP, any chances to run that are missed is a loss to the owner. The facility's equivalent availability factor for winter months has increased from a low of 95% to a high of 99.9% over the course of the last three to four years due primarily as a result of the programs cited above.

Project participants:
The entire plant staff



LEARN WHAT YOU DON'T KNOW

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. The **CT-Tech** class on **Repair Processes** will be presented by **PSM — An Alstom Company,** on Tuesday, September 10. **National Electric Coil** will teach **Generator Fundamentals** on Wednesday, September 11. Both companies are CTOTF Super Champions.

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

CTOTF

Fall 2013 Conference
Coeur d'Alene, Idaho
September 8-12, 2013

CT-Tech

CT-Tech Classes on Tuesday and Wednesday evenings

Registration information available at www.CTOTF.org in July

Improvements to plant permit process benefits safety

Best Practices Award

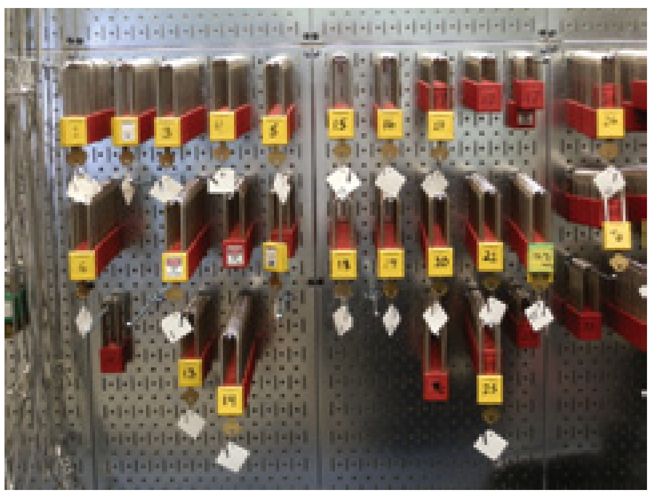
McClain Power Plant
Owned by OGE Energy Corp and Oklahoma Municipal Power Authority
Operated by OGE Energy Corp
520-MW, gas-fired, 2 × 1 combined cycle located in Newcastle, Okla
Plant manager: Tony Shook

Challenge. During turnaround (outage) periods at the McClain Energy Facility, our permit process implementation for lock-out/tag-out (Loto) clearances, confined space, hot work, etc, had resulted in safety near-miss occurrences, the majority of which were caused by simple human error as the result of distraction.

Workers missed permit process steps because of distraction caused by unintentional disorder materializing when contractors corralled the space to request a permit or to manage existing permits. This uncontrolled access would create a means for disorder, thus becoming the culprit of distraction leading to process step mismanagement.

Solution. After an in-depth review of the facility's permit process implementation, plant leadership determined a more rigorous system could be employed to further mitigate the potential for human error. The following depicts the process enhancements made:

- Designed and constructed a dedicated work-space permit area attached to the control room solely for the facilitation of clearances and all other outage-related permits (Figs 1, 2).
- During outage periods, the shift supervisor or designee is deemed "outage coordinator," and is accountable for all permit process/procedure coordination and implementation.
- Restricted the access of all non-essential personnel to the permit/control room space. Previously, during outage periods, contractors and others would enter the control room, as it was the accepted practice for permit handling.
- Installed a service window in the permit work space to control (one at a time) engagement between personnel and the outage coordinator for clearances and other permit handling (Fig 3).
- Modified the plant's safety indoc-



1, 2. Dedicated work space for permitting (left) is attached to the control room. Locks for Loto system are at right

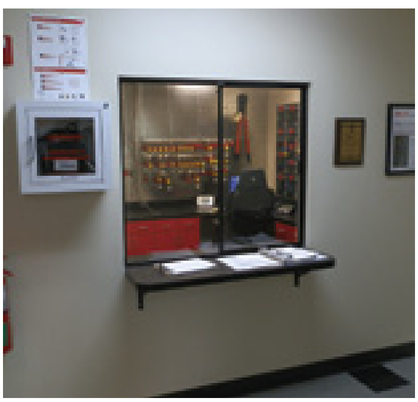
Benjamin Privett

trination training to include awareness for the new process enhancements.

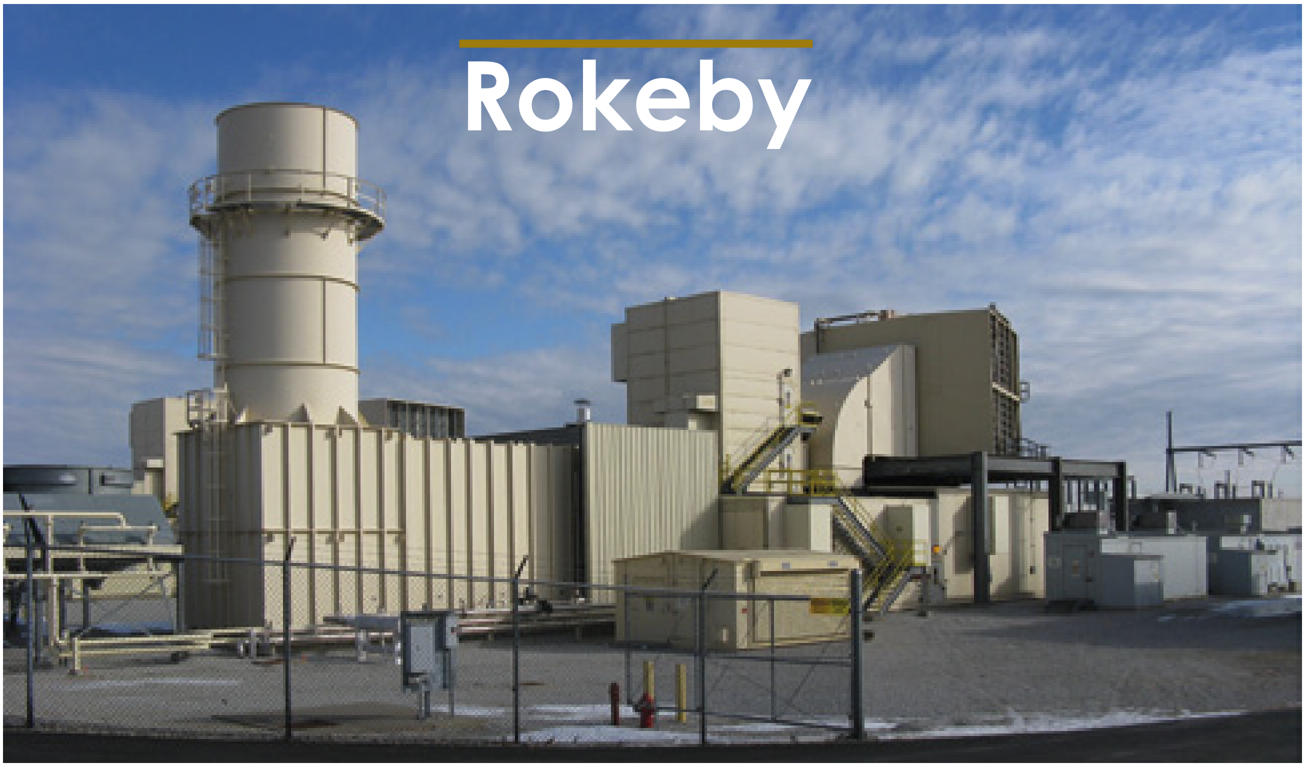
Results. The new permit work space now provides a central area to store, manage, and facilitate—namely clearances—both member and contractor permitting. We included storage cabinets, lock boxes, metal pegboard, SAP clearance management center, and telephone as means to authenticate, define, and appraise the new process-control rigor.

However, the true testament of success is yet to be measured as the plant has yet to undergo an outage since the addition of the permit room. Plant personal undoubtedly know that this project is and will continue to be a great enhancement of safety success.

Project participants:
Tony Shook, plant manager
Benjamin Privett, operations manager
Michael Booher, shift supervisor
Billy Bowien, shift supervisor
Joel Hinson, shift supervisor
Gerald Keeling, shift supervisor



3. Service window enables the outage coordinator to focus exclusively on the needs of a single worker requiring a clearance and/or work permit



Comprehensive hazardous spill mitigation strategy

Best Practices Award

Rokeby Generating Station

Lincoln Electric System

245-MW, dual-fuel, simple-cycle peaking facility located in Lincoln, Neb

Plant manager: Bruce Barnhouse

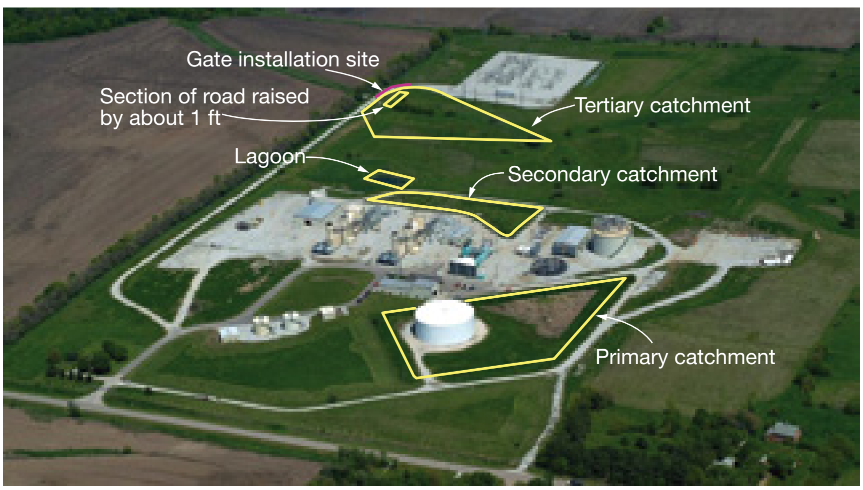
Challenge. Rokeby Generating Station consists of three legacy frame gas turbines and one black-start diesel/generator with a total plant capacity of 245 MW. The site also has two thermal storage systems with associated refrigeration equipment. Rokeby's original GT operated only on fuel oil but with plant expansion, two dual-fuel units were constructed and the older unit was converted to be dual-fuel capable.

Even though the generating units normally burn natural gas, there is a 5-million-gal fuel-oil storage tank onsite which is supplied by an intrastate pipeline. The site also supports miscellaneous equipment with various types and quantities of oil and other fluids. As part of the spill risk mitigation program, Lincoln Electric System evaluated how to protect the environment from a large oil release from either the storage tank or the pipeline.

Solution. There were two fundamental approaches to the spill mitigation strategy: (1) onsite containment and (2) offsite containment. The onsite containment strategy was implemented in three phases (Fig 1).

First, the spill containment berm around the storage tank was re-engineered and expanded because the original containment capacity was less than 5 million gallons.

Second, the geography of the site allowed for construction of containment gates on drainage structures. A



1. Spill containment areas are superimposed on site aerial photo

Bruce Barnhouse

relatively small drainage ditch which runs along the east side of the plant's switchyard provided adequate storage for turbine or refrigeration system fluids or GSU oil releases. A manually operated slide gate was installed on the associated 2-ft drainage culvert.

Further "downstream," three 4-ft culverts provided a final opportunity to keep any spills from leaving the site and entering a stream located directly next to the plant's property line. An engineering analysis indicated a plant road that ran along the site property line, next to the stream, could be used as a containment dam by installing three manually operated, 6 × 4-ft slide gates on the existing culverts. The analysis also determined that by raising the elevation of a 150-ft section of the road by approximately 1 ft, the containment could be increased from 1.38 to 2.32 million gallons.

2. Spill response trailer has 150 items for use in containing oil releases

Finally, if a spill does make it offsite to the stream, the plant has put together a spill response trailer with 150 items (Fig 2) that can be used to contain oil releases on moving water (sidebar). Plant personnel periodically hold spill-containment exercises which helps them identify the best access points along the stream to intercept a spill, as well as how to properly deploy the spill containment equipment.

Project participants:
Bruce Barnhouse, plant manager
Joe Komenda, project engineer

Contents of spill-response trailer

Motor/generator, 1 (Briggs & Stratton)
Water booms, 4 (Pig Corp)
Water-boom tow bridles, 4 (Pig Corp)
High dry absorbent, 56
Pad rolls, 4 (Pig Corp)
Oil booms, 2 (Pig Corp)
Drain covers, six 20-in. round
Drain covers, two 42-in. round
Drain cover, one 30-in. round
Drain covers, two 42-in. square
Fence posts, six 6-ft posts
Fence-post driver, 1
Caution tape, 2 rolls
Sand bags, 100 (empty)
Tyvek coveralls, 25
Hip waders, 2 each, sizes 11 and 13
Extension cords, four 50-ft cords
Traffic cones, 4
Tripod lights, 2
Flashlights with batteries, 2
Headlamps with batteries, 4
Pointed shovels, 2
Flat shovels, 2
Rakes, 2
Machetes, 2
Fire extinguisher, 1
First-aid kit, 1
Folding chairs, 2
Rope, one 600-ft spool of ½-in. rope
Rope, one 600-ft spool of ⅜-in. rope
Utility knives, 2
Locking carabiners, 10
Gloves, brown cuff L/XL, 4 pair
Gloves, green cuff S/M, 4 pair
Traffic vests, 4
Life vests, 2 L and 2 XL

Granite Ridge

Chemical delivery drivers welcome safety cards

Best Practices Award

> **Granite Ridge Energy**
>
> *Owned by Granite Ridge Energy LLC*
>
> *Operated by NAES Corp*
>
> 730-MW, gas-fired, two-unit, 1 × 1 combined cycle located in Londonderry, NH
>
> **Plant manager:** William Vogel

Challenge. Contractors that work at Granite Ridge Energy (GRE) attend a comprehensive safety orientation program to familiarize them with plant safe operating procedures, emergency response, and evacuation. Chemical delivery drivers, however, do not receive any formal safety training because they are escorted by plant personnel and monitored during the off-loading process. If the plant escort had to leave because of a plant emergency, or became incapacitated, chemical delivery drivers may not know whom to call or how to evacuate the facility.

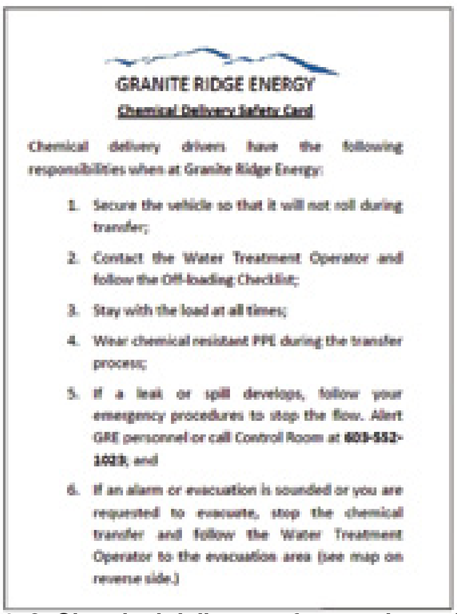
Solution. Plant personnel developed a site-specific safety checklist and information card for chemical delivery drivers in order to familiarize them with the facility's rigorous safety requirements and proper protocol in case of an emergency.

Jim Carlton

The chemical delivery safety card was designed to give drivers easy and safe operating procedures including the phone number of the control room and an evacuation map which is printed on the back of the card (Figs 1 and 2). The cards are printed in color on durable card stock and are issued to drivers for every delivery as part of the chemical delivery checklist.

Results. Chemical drivers keep the cards on the dashboards of their trucks or with the delivery paperwork. They have commented that it is helpful to have site-specific safe operating procedures so close at hand in a clear, concise manner. The safety card also gives GRE personnel peace of mind that all drivers, regardless of their experience, have the information they need to follow basic safe operating procedures, respond to an emergency, and evacuate the facility without relying on site personnel.

Project participant:
Susan Prior, EHS manager

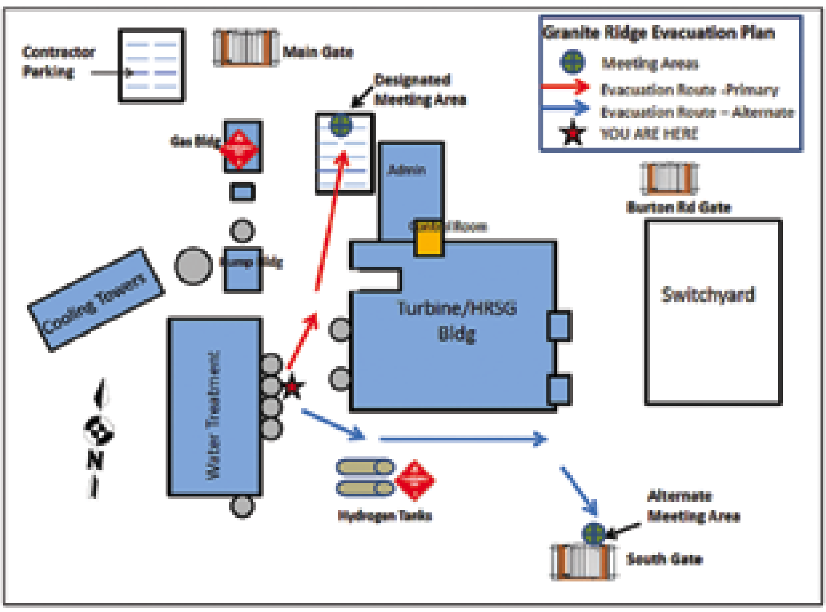


GRANITE RIDGE ENERGY

Chemical Delivery Safety Card

Chemical delivery drivers have the following responsibilities when at Granite Ridge Energy:

1. Secure the vehicle so that it will not roll during transfer;
2. Contact the Water Treatment Operator and follow the Off-loading Checklist;
3. Stay with the load at all times;
4. Wear chemical resistant PPE during the transfer process;
5. If a leak or spill develops, follow your emergency procedures to stop the flow. Alert GRE personnel or call Control Room at **603-552-1023**; and
6. If an alarm or evacuation is sounded or you are requested to evacuate, stop the chemical transfer and follow the Water Treatment Operator to the evacuation area (see map on reverse side.)

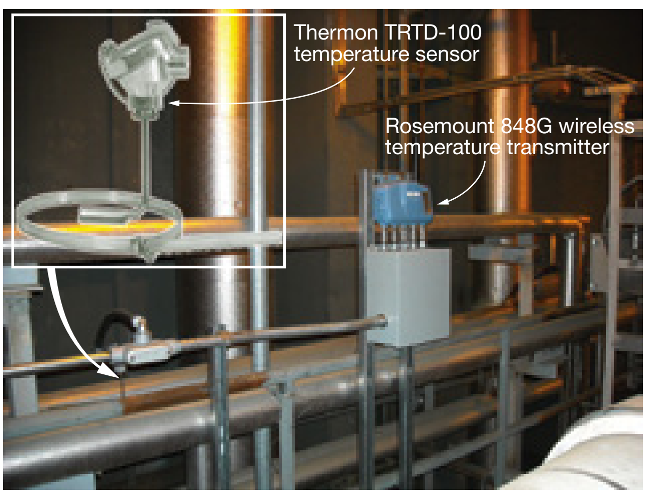


1, 2. Chemical delivery safety card gets high marks from truck drivers servicing Granite Ridge Energy

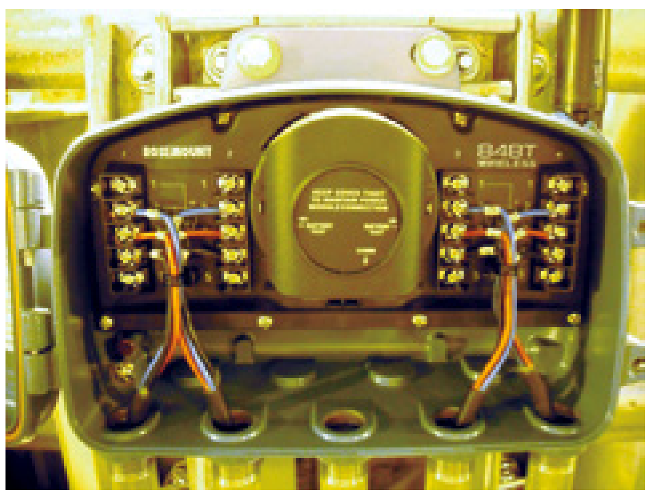
Wireless monitoring of HRSG drain valves pinpoints energy waste

Challenge. Determining and then chasing-down leak-by on manual drain valves or failing steam traps can be difficult—especially with common drain headers which handle multipurpose functionality. Typically, these areas do not have any instrumentation for monitoring leaks; plus, they are insulated, which makes using hand-held temperature guns difficult at best. Installing instrumentation and then updating the facility's distributed control system is expensive and generally difficult to justify economically.

Solution. GRE used its existing wireless ancillary monitoring system (AMS), installed to monitor the heath of critical-service automated valves, and battery-powered strap-on RTDs, placed strategically on high-volume drain headers to track temperature step changes over time, to provide rapid identification of leak-by issues (Fig 3). The cost of installation was mitigated by using the plant's PI system for tracking versus the DCS, and battery-powered technology versus hardwiring of the RTDs (Fig 4).



3. Wireless AMS system and battery-powered strap-on RTDs alert when leak-by of drain valves occurs



4. Battery-powered external device, simplifies installation

The batteries are expected to last five years; the system alarms when power is getting low.

Results. GRE already has realized successful identification and affected change of leak-by from unseated valves.

Project participants:
Dan Jorgensen, maintenance manager
Rick Davis, I&C technician
Larry Hawk, plant engineer

Communications initiative leads to multi-faceted returns

Challenge. Recognizing flaws and inefficiencies in our plant's communications systems, personnel created a list of issues associated to this area culled from work orders from the facility's CMMS and tribal knowledge to highlight solutions with low-investment, high-return potential. In 2012 Granite Ridge Energy undertook a broad initiative to identify, prioritize, and improve issues surrounding its communications systems and practices to optimize effectiveness and cost.

Solution. Work began on several projects including a wireless cell phone repeater system, electronic bulletin board, and communications circuit assessment:

Cell phone repeater project. Like most powerplants, GRE buildings are chiefly of metal construction and, at least in our case, this blocked relatively strong wireless signals from inside the buildings. This created several issues, including contractor management. Example: A foreman trying to coordinate support or get technical questions answered. It also made operations staff overly dependent on our wired infrastructure—susceptible to snow-, wind-, and ice-related storms without backup communications in place.

GRE looked at several solutions and found a repeater system that could inject cell tower signal strength inside these "dead-zone" buildings, without tying up any network bandwidth; plus, it is not carrier-specific. By using one antenna, an amplifier, and several repeaters, GRE realized its goal (Figs 5, 6).

Electronic bulletin board. GRE installed and maintains an electronic bulletin board which has two screens, the top screen cycles through a PowerPoint presentation that includes incentive tracking, employee training statistics, health and safety announcements, and upcoming events. This presentation is routinely updated.

The bottom screen has an OSI PI process book which shows real-time plant statistics, minimizing the need to enter the control room on off-the-cuff inquiry needs (Fig 7). This has been received positively by employees and visitors.

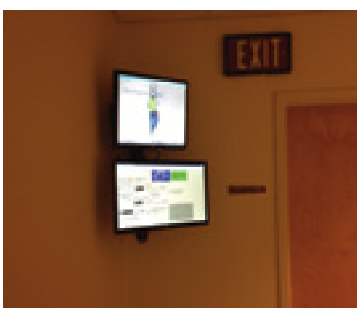
Communications lines assessment and coordination. GRE has been commercial since early 2003 witnessing transitions like OEM remote support from direct-dial modems to Internet-based platforms. The need for expensive T1 lines diminishes, in lieu of more cost-effective substitutes.

By assessing the current open telephone lines and making cost-effective changes like moving copper-line phones over to the VOIP system already in place, canceling our bonded T1 for Internet access, and moving to a business cable modem (10 times the bandwidth for one-tenth the cost), and using wireless bridges in place of telephone circuits on short-distance applications, GRE was able to identify about 15 unnecessary telecom circuits, saving the company about $1500 a month in recurring fees (Fig 8).

Results. GRE has been able to improve communications inside and outside of its organization while enjoying immediate return on investment through a multi-pronged approach.

Project participants:
Larry Hawk, plant engineer

5. Repeater system for injecting signal strength inside "dead-zone" buildings has these basic components: outdoor antenna, amplifier (blue), indoor repeater (white), and cabling



6. Antenna for repeater system is installed on top of GRE's administration building (above)

7. Electronic bulletin board is located outside the control room (left)

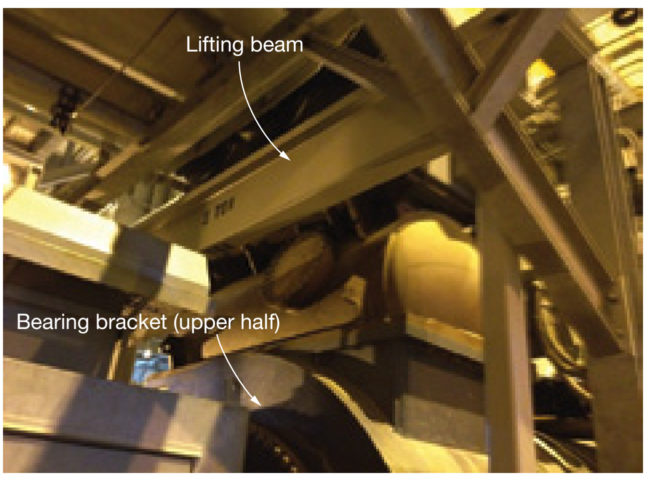
8. Orange tape identifies telecom circuits no longer needed (right)

Engineered solution to facilitate generator inspections

Challenge. During generator inspections it is necessary to remove selected components for inspection and testing purposes. To remove the upper half of the generator collector-end bearing bracket it is necessary to install rigging and lifting equipment directly overhead to do the job properly. Unfortunately, the area overhead contains the electrical isophase ductwork which has the main leads coming from the generator. This assembly is lightweight (aluminum). The weight of the bracket exceeds the integrity of the ductwork, producing an unsafe condition. As a result, there is no safe way to rig and remove the bracket unless the overhead isophase ductwork is removed.

Solution. To provide a safe lifting point for bracket removal, the concept of using a lifting or support beam was identified (Fig 9). This beam was engineered so that it could be installed over the bracket area and extends off to the side towards an open area adjacent to the generator itself (Fig 10). This allows the lifted bracket to be positioned away from the generator and onto to the floor below.

Project participants:
Dan Jorgensen, maintenance manager



9. Lifting beam, rated 9 tons, is in position over the bearing bracket

10. Beam and hoist arrangement is ready for use

Saltillo

ACC fan-blade pitch optimization

Best Practices Award

Central de Ciclo Combinado Saltillo
Owned by Falcon Group
Operated by Comego SA de CV
250-MW, gas-fired, 1 x 1 combined cycle located in Saltillo, Coahuila, México
Plant manager: René Villafuerte

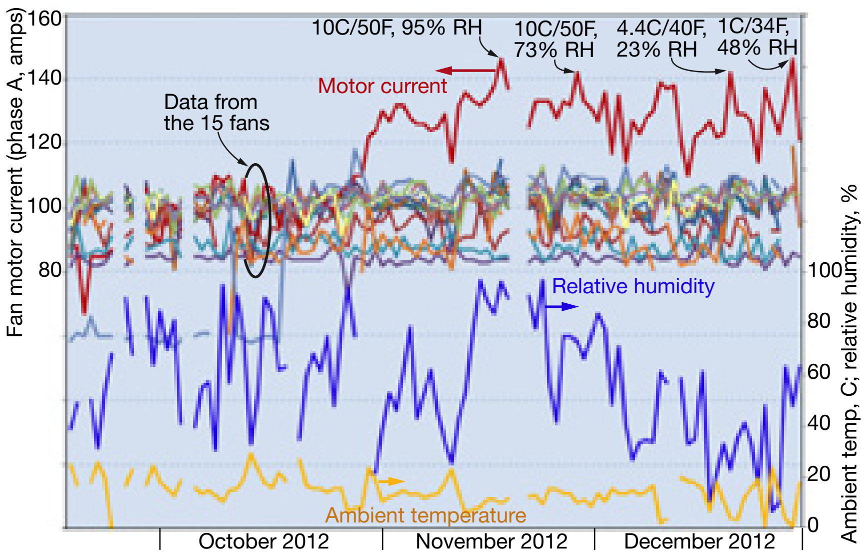
Challenge. Critical to success in the operation of air-cooled condensers (ACCs) is maximizing the air flow through each fan. Air flow varies with (1) fan-blade pitch—a/k/a angle of attack, which is generally fixed and cumbersome to adjust—and (2) ambient conditions: temperature, relative humidity, and sometimes wind speed below the ACC. It's important for operators to avoid tripping the fan motors on current overload during adverse weather conditions (low temperature and high humidity).

Normally, air flow is calculated using a heat balance with inlet and outlet air temperature (taken manually), and the air speed after the fans using a portable anemometer. However, these data are neither easy to obtain nor entirely reliable for making fan-blade adjustments, because of instrument limits.

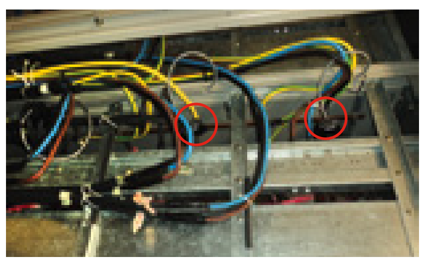
Solution. To operate at maximum air flow, it is necessary to maximize motor current—that is, maximize the torque ultimately applied to the fan—while staying below the stalling fan pitch (Fig 1). Thus it's beneficial to have an electrical consumption reference, at the lowest possible cost. Current pickups (transformer donuts) were installed on the switchgear for each ACC fan (Fig 2) and wired to an off-the-shelf digital recorder/display (Fig 3). With those simple devices, the following action plan was made possible:

- Record data daily and correlate electric-current values with weather conditions (ambient temperature and relative humidity).
- Adjust the angle of attack (AoA) of fan blades to check air flow versus electric current (Figs 4, 5).
- Use the data during winter, when the air density is highest and the worst conditions are present (100% RH and 32F), to maximize the AoA for each fan to just below trip value for the most challenging ambient conditions.

Results. The adjusted fans, after AoA increase, show significant increase in air flow and electric current, while working slightly under the trip setting at the highest air-density conditions. The benefit of this analysis: During summer, when air density is low, the fans will be working at maximum air flow—therefore, at maximum ACC condensing capability, without the need

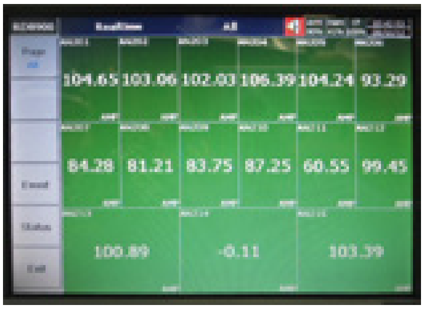


1. Electric current trend analysis shows that as temperature drops and humidity rises, energy consumption increases. The red curve is for the test fan. Its AoA was increased to fully use the electrical power available during summer, but without tripping in winter and without reaching the fan-blade stall angle

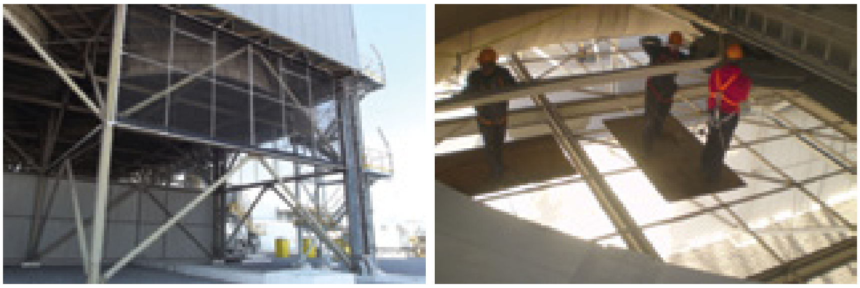


2. Current transformers were installed on the switchgear for each fan to capture data

Juan Diaz, René Villefuerte, and **Roberto Hernandez** (l to r)



3. The current pickups in Fig 2 were wired to an off-the-shelf digital recorder/display



4, 5. The ACC fan cell where the AoA was changed is at the left, workers adjusting the angle of attack are at the right

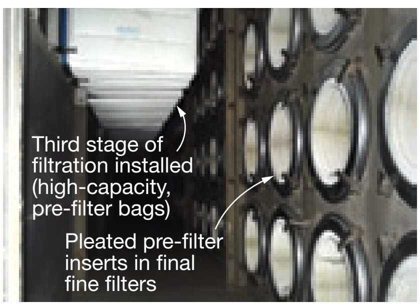
to change the AoA setting between summer and winter conditions.

Project participants:

Gerardo Rasgado, I&C engineer (in memoriam)

Mario Gonzalez, electrical engineer

6. Pleated, fine pre-filter protects the final filter



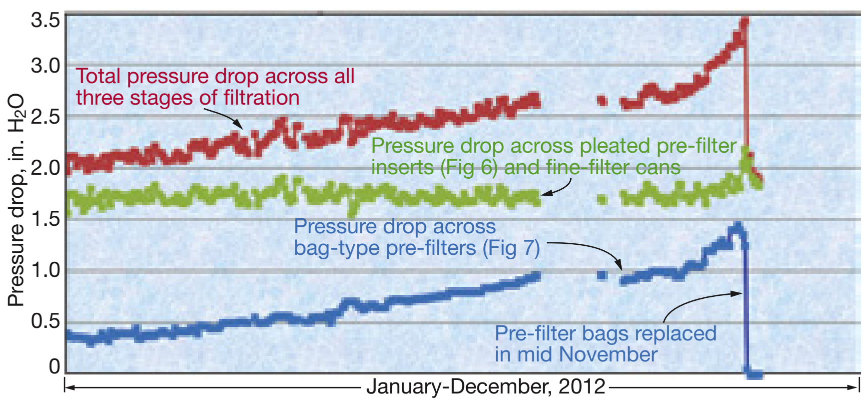
7. Bag-type pre-filters were installed in front of the main filter wall in the inlet house to extend the interval between filter replacements

Gas-turbine-inlet air filtration improvement

Challenge. Since the beginning of Saltillo operations, the dust in the plant's desert environment has been one of the main issues affecting the gas-turbine inlet, made worse by the extremely fine dust from a neighboring cement manufacturing facility. The operational lifetime of the inlet air filters was extremely short (four to six months). A unit shutdown was required for replacement, with the associated economic downside.

After several studies, the pre-filter insert for the fine-filter cans was changed from an open fabric depth filter to a pleated fine-surface product (Fig 6). The latter had much more surface, increasing both filtration efficiency and the life of the final fine filter. Despite those changes, the period to replace final fine filters was still about six months, and the pleated pre-filters required up to four changes per year—quite an expense.

Solution. In order to catch most of the dust particles ahead of the pleated fine pre-filters, a third filtration stage was installed inside the existing fil-



8. Bag-type pre-filters (bottom curve) do an excellent job of protecting the pleated pre-filter inserts and final fine-filter cans—as the middle curve indicates by its flatness (virtually no increase in pressure drop over time) ter house, in front of the main filter wall. It involved constructing a lattice framework with steel angle, and using standard-size frame filter bags, which offer a very large filtration surface and dust holding capacity (Fig 7).

Also, an additional differential-pressure gage was installed. The end result is a three-stage filtration system, using a very-high-area fine pre-filter (bags), then the pleated pre-filter inserts inside the final fine-filter cans.

Results. The three filtration stages were installed at the last outage, and the filter bags were removed 11 months later—with minimum fouling of the pleated pre-filters and final fine filters—thus increasing the operational lifetime of GT inlet to a year, the standard time between outages, and eliminating the need for a mini-outage because of high differential pressure (Fig 8).

Project participants:
Roberto Hernandez, maintenance manager
Lamberto Ortega, mechanical engineer

Fuel-oil recirculation arrangement saves money, mitigates spill risk

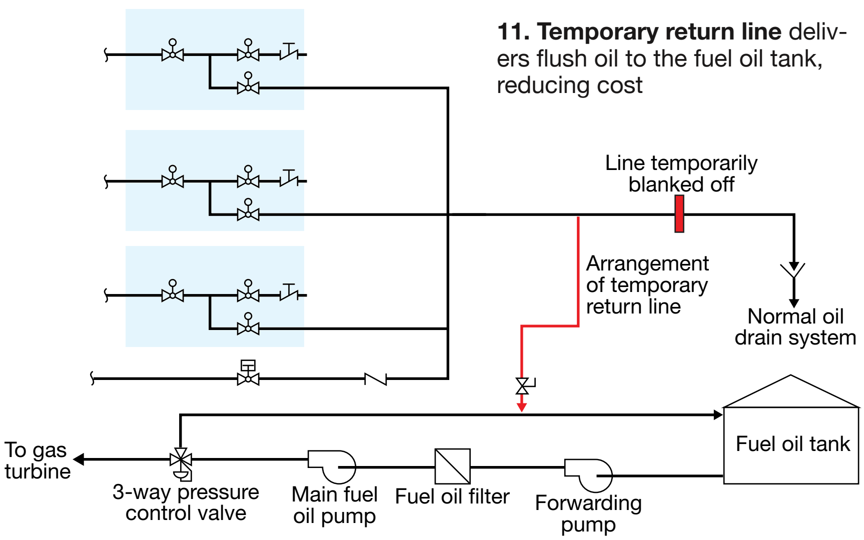
Challenge. During fuel-oil re-commissioning, one of the main activities is flushing of lines using the full flow of the main fuel pump to prevent debris accumulation. However, such flushing involved sending "dirty" fuel oil (which has minimal contamination) to a tanker truck for later disposal. The economic impact and environmental liability attached to this operation are extremely high.

Solution. Instead of sending flush oil to drain, an OEM-validated temporary system was installed using a special hose to send that fuel to the return line after the 3-way pressure-control valve (Figs 9-11).

Results. Fuel oil flushing was performed within the required time, with full fuel flow, ensuring pipe cleanliness and debris removal—leading to a successful fuel-oil start.

Project participants:
Juan Diaz, operations manager
Guillermo Rivera, shift engineer


9, 10. Fuel-oil hose runs from the turbine enclosure (left) to a valve installed in the fuel-tank return line (right)



11. Temporary return line delivers flush oil to the fuel oil tank, reducing cost

Sabine Cogen LP

Owned by ArcLight Capital Partners and NRG Energy
Operated by Consolidated Asset Management Services

105-MW, gas-fired, 2 x 1 combined-cycle cogeneration facility located in Orange, Tex

Plant manager: Tim Hevrin

Safety database developed in-house effectively tracks, validates contractors

Best Practices Award

Challenge. Sabine Cogen, operating commercially since January 2000, is a 2 × 1 combined-cycle cogeneration plant providing electricity to the grid and to a nearby rubber processing facility. The facility burns natural gas and has an equipment rating of 105 MW. The site has nine full-time employees, plus operators on loan from the neighboring steam host.

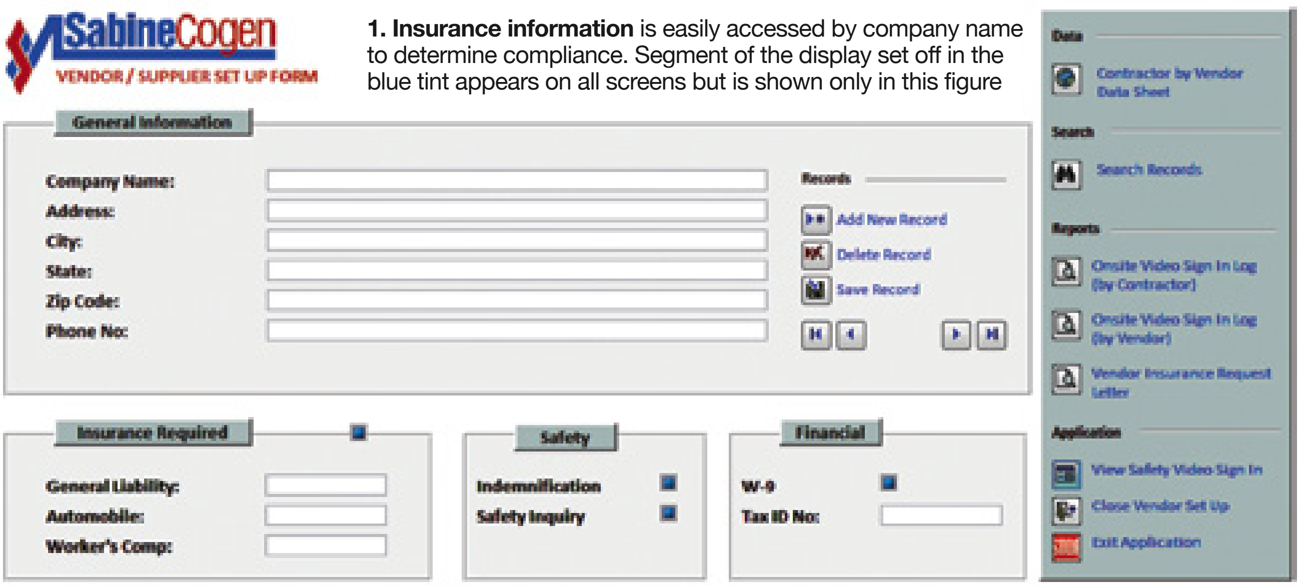
Outside contractors are needed to assist in completion of day-to-day repairs, maintenance, and major maintenance activities. All outside contractors are subject to the facility's insurance requirements and must receive safety orientation prior to commencing work onsite.

Historically, in an attempt to track required contractor insurance documentation, the site maintained a spreadsheet containing contractor names and insurance expiration dates. Periodically, the expiration dates were sorted and letters requesting updated insurance certificates were then manually issued. This system was not successful in that insurance certificates were expiring prior to letters being issued, and some contractors were found to be working onsite without proof of current insurance on file. All staff members could not readily access the spreadsheet.


Tim Hevrin

Further, the system did not preemptively alert staff members of when insurance certificates were to expire or whether or not the contractor being called upon had an insurance certificate on file at all. Gaps in the previous system made the site vulnerable to having contractors performing work on site without required insurance coverage and created the labor-intensive tasks of manually tracking dates and issuing request letters.

In addition, outside contractors are required to watch a site-specific, safety orientation video initially and subsequently on an annual basis. Although a written registry was maintained and dated hardhat stickers were distributed, the site was unable to efficiently track which contractors had received the training and the annual training expiration dates.

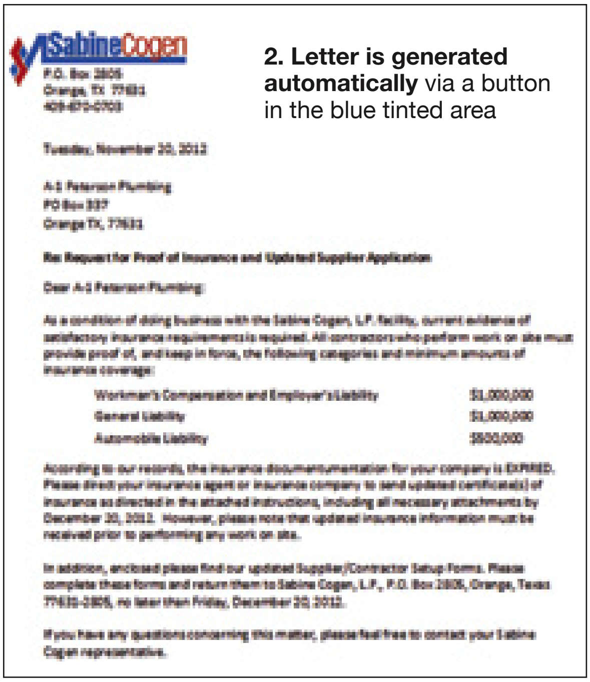


1. Insurance information is easily accessed by company name to determine compliance. Segment of the display set off in the blue tint appears on all screens but is shown only in this figure

Solution. To address the challenge of verifying current contractor insurance, a database was developed in-house to track certificate expiration dates. The database was developed using Microsoft Access with one table to store company data. Company names and insurance information can be easily searched, entered, and updated because of the user-friendly format of the database (Fig 1).

Data validation and input masks were used to ensure the integrity of any entered information. All staff members now have access to the centrally located database. A query was programmed within the database to easily identify company records with expired insurance certificates.

Additionally, a report was created, linked to the expiration query, which automatically generates request letters (Fig 2). The report is run quarterly. Fields are auto-populated with company information and the request letters and associated address labels are automatically generated. The report includes companies with insurance certificates that have either expired or will expire within the next three months.


SabineCogen
P.O. Box 2805
Orange, TX 77631
[illegible]

Tuesday, November 20, 2012

A-1 Peterson Plumbing
PO Box 337
Orange TX, 77631

Re: Request for Proof of Insurance and Updated Supplier Application

Dear A-1 Peterson Plumbing:

As a condition of doing business with the Sabine Cogen, L.P. facility, current evidence of satisfactory insurance requirement(s) is required. All contractors who perform work on site must provide proof of, and keep in force, the following categories and minimum amounts of insurance coverage:

Workman's Compensation and Employer's Liability	$1,000,000
General Liability	$1,000,000
Automobile Liability	$500,000

According to our records, the insurance documentumentation for your company is EXPIRED. Please direct your insurance agent or insurance company to send updated certificate(s) of insurance as directed in the attached instructions, including all necessary attachments by December 20, 2012. However, please note that updated insurance information must be received prior to performing any work on site.

In addition, enclosed please find our updated Supplier/Contractor Setup Forms. Please complete these forms and return them to Sabine Cogen, L.P., P.O. Box 2805, Orange, Texas 77631-2805, no later than Friday, December 20, 2012.

If you have any questions concerning this matter, please feel free to contact your Sabine Cogen representative.

2. Letter is generated automatically via a button in the blue tinted area

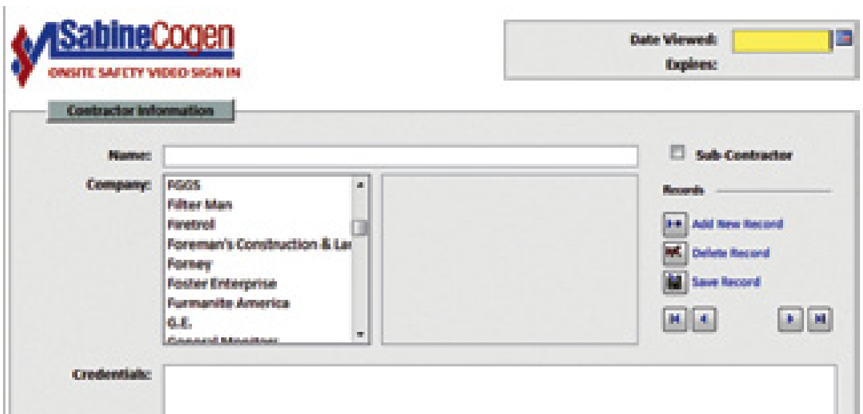
The database enables the site to easily identify contractors with insurance certificates that will expire ahead of time and significantly reduces man-hours needed to send requests for updated information and to track expiration dates.

The site still faced the challenge of tracking individual contractor orientation. The database was revised to include a second table for individual contractor information. A one-to-many relationship was developed linking individual contractors to their corresponding company, and a safety orientation sign-in screen was created (Fig 3).

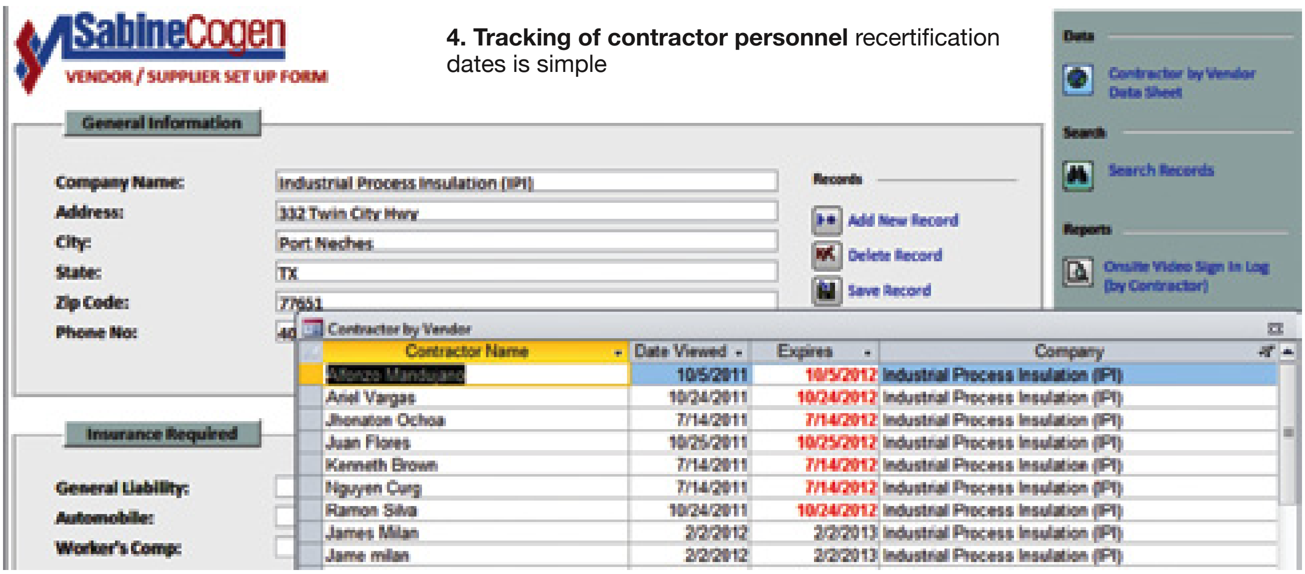
Upon initial arrival, the individual's information is entered into the database, which includes name, employer, and the date of the initial safety orientation. The database automatically generates an expiration date as to when the individual's training must be renewed.

As the contractor is entered into the system, the associated company is selected from a pull-down menu of the previously entered data used for tracking insurance certificates. A sub-form located on the sign-in screen displays whether or not the outside company has current insurance information on file; therefore, the site is able to verify individual orientation status and company insurance documentation simultaneously.

Additionally, from the "Company View" screen, a list of each individual contractor that has a record can be easily viewed in a data sheet (Fig 4). The database also has the capability of scanning and storing safety training



3. Safety orientation sign-in screen



4. Tracking of contractor personnel recertification dates is simple credentials, such as for heavy-equipment operators, for each individual. Future plans for the database include adding a safety rating to the contractor information based on initial contractor evaluations.

Results. Overall the in-house design and development of the safety database has provided Sabine Cogen with a cost-effective and efficient means of recording and tracking key contractor safety information. The database has significantly reduced the man-hours previously required to manage the same information.

Verifying that outside contractors have the required insurance in place contributes to the protection of both the site and the individual contractor in the event of a safety-related incident. Because of the central location of the database and the easy-to-use screens, all site employees can now verify that contractors receive initial and annual site-specific safety information prior to commencing work. Because the tracking methods were developed internally, the site has the luxury of continuously improving the safety database as the need arises.

Project participants:
Brandy Dabbs, field coordinator
Rachal Havens, EHS specialist

Monitoring CEMS gas bottle pressure ensures compliance

Challenge. The continuous emissions monitoring system is a requirement for air permits and environmental regulatory compliance. CEMS provides a means of quality assurance, monitoring, and reporting for the site's air emissions data and aids in the prevention of upset emission events and air-permit deviations.

The Sabine Cogen facility uses EPA protocol mixed gases for a daily calibration test that allows its analyzers to be proven accurate while remaining online. With any bottle service such as this, the potential to develop leaks or to exhaust all bottle pressure is very high. With the depletion of one of the mixed-gas bottles, it would result in a notice of violation for missed calibrations which can be very costly if not managed properly because of consequent material loss, environmental violations, personnel callouts, and overtime charges.

Solution. Sabine Cogen is committed to implementing effective, cost-saving solutions while maintaining optimal operation. One such solution was accomplished by integrating pressure switches on each of the daily calibration protocol gases while in service. A pressure switch has been installed for each of the protocol gases in service and the switches have been set at 200 psig.

The switches are integrated into the facility DCS, which allows operations to be notified immediately if a low pressure occurs. This alerting system allows ample time to remove and replace protocol gas bottles and to recalibrate the CEMS system, which prevents CEMS downtime and potential air permit violations and allows repairs and bottle changes to occur during normally scheduled work hours.

Results. As a result of the new system, after-hours call-outs for CEMS bottle replacements have been eliminated. Sabine Cogen has realized a cost savings in materials, labor, and potential environmental fines as a result of the new bottle pressure monitoring system.

Project participants:
Scott Spillane
Darrell Hypolite
Tommy McLeod
Joe Vincent

MEAG Wansley Unit 9

Owned by Municipal Electric Authority of Georgia
Operated by GE Power Generation Services

503-MW, gas-fired, 2 × 1 combined cycle located in Franklin, Ga

Plant manager: Keith Feemster

Post-maintenance checklist for critical instruments

Best Practices Award

Challenge. During plant outage periods, the alignment of system instrumentation, valves, and other critical equipment is often altered to facilitate calibration, maintenance, and testing. Because of the site's limited O&M staff, third-party vendors are routinely used to perform required instrument calibrations and valve repair/maintenance. Direct oversight of these activities and ensuring equipment is returned to normal conditions can be challenging for such a limited staff.

Following the conclusion of these outages, the site had experienced failed starts, unit trips, and forced outages attributed to the misalignment of instrumentation and valves. Lock-out/tag-out programs generally ensure proper system line up, but some activities may leave instrument valves that are easy to overlook or not part of a Loto process in the incorrect position.

Solution. To prevent failed starts, unwanted trips, and additional outage time, the site identified instrumentation and valves critical to plant operation. These instruments and valves were listed in a table that formed the basis for a post maintenance instrument procedure.

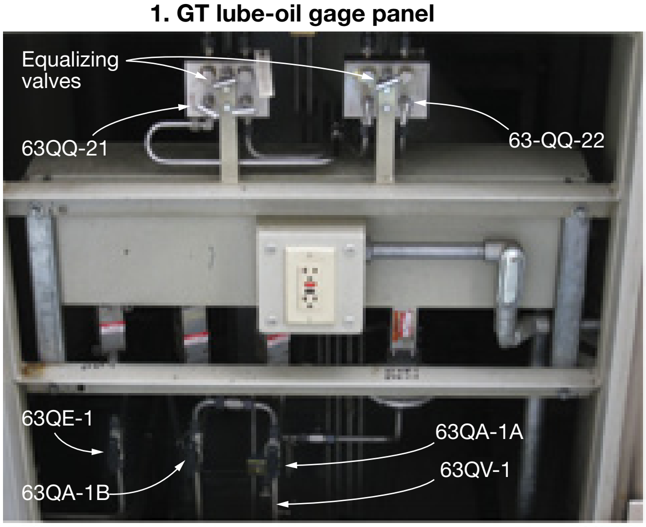

Keith Feemster

The procedure contains a checklist which consists of the name of the critical equipment, the instrument identification number, valve identification number, and the correct valve position (Figs 1, 2). Pictures are included to assist personnel in identifying the correct location, the correct valve, and the correct handle position of these valves.

Results. The implementa-

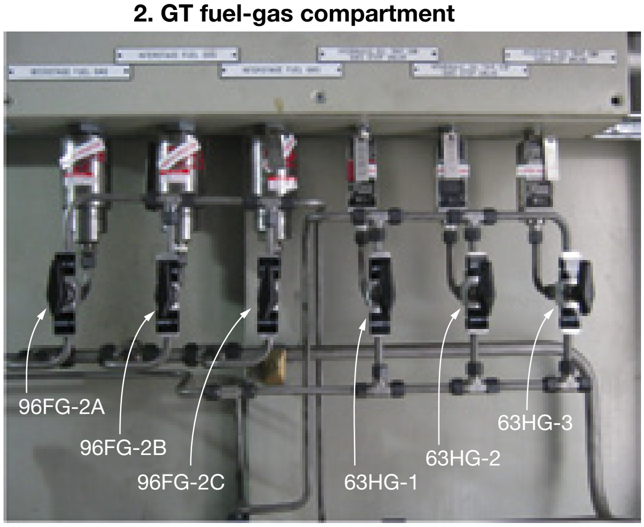
Photos bring checklist to 'life'

1. GT lube-oil gage panel



Position	Instrument	Valve number/nomenclature
Down	63QE-1	Emergency LO pump run
Down	63QA-1A	LO pump bearing header pressure
Down	63QA-1B	LO pump bearing header pressure
Open	63QV-1	LO tank pressure
Open	63QQ-21	North LO filter D/P high side
Open	63QQ-21	North LO filter D/P low side
Closed	63QQ-21	North LO filter D/P equalizing valve
Open	63QQ-22	South LO filter D/P high side
Open	63QQ-22	South LO filter D/P low side
Closed	63QQ-22	South LO filter D/P equalizing valve

2. GT fuel-gas compartment



Position	Instrument	Valve number/nomenclature
In service	63HG-1	Fuel-gas stop valve hydraulic pressure
In service	63HG-2	Fuel-gas stop valve hydraulic pressure
In service	63HG-3	Fuel-gas stop valve hydraulic pressure
In service	96FG-2A	Interstage fuel-gas pressure
In service	96FG-2B	Interstage fuel-gas pressure
In service	96FG-2C	Interstage fuel-gas pressure

tion of the post-maintenance instrument checklist has eliminated failed starts and unit trips caused by the misalignment of instrument valves. The pictures included with the checklist readily identify the location and correct position of these valves.

Project participants:
Dana French
Bert Wright

'Scratch out' accidents program promotes safety vigilance

Challenge. Complacency can be the most dangerous enemy at any facility. When your site has achieved the pinnacle of safety achievements, VPP Star status and an enviable lengthy safety record, the most logical question is what's next?

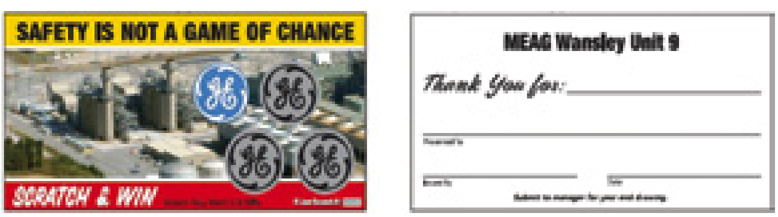
How do we improve on a great safety culture? Are your employees thinking "I have done this many times with no injuries…?" Do your employees consider themselves "the best" at what they do? It's important to remember, when you are at the top, sometimes the only way to go is down.

Solution. Site employees designed and implemented a program to reward safe work habits. When someone is "caught in the act" working safe or reporting a hazard, the persons involved are awarded a safety scratch-off card, which is similar to a lottery scratch-off ticket (Fig 3). Match two of the scratch-off sections and win one of three levels of awards. The card can then be redeemed at the Safety Office for items ranging in value up to $25.00. The items may include ball caps, multi-tools, flashlights, personal coolers, fire extinguishers, smoke detectors, and more. These items are readily available from a variety of vendors making the program easily customizable to suit any demographic.

Results. The cards provide instant recognition for safe behavior and hazard identification. They are also very well received by employees and contractors alike. Hazard recognition reports have increased dramatically since the inception of the program and the "buzz" at the site about the program keeps safety in the forefront of everyone's mind.

Additionally, during a recent successful VPP Recertification Audit, the program was reviewed by the inspection team and received positive comments from all concerned. The reasoning is sound, the program does not reward non-reporting of injuries or dangerous conditions. Its proactive approach motivates employees and contractors to contribute valuable information concerning hazardous conditions, a catalyst for prevention of accidents and injuries. Focusing on leading indicators has always been a key component in any good safety program; stopping accidents before they happen is a benefit everyone can 'live' with.

Project participants:
Todd Candler
Keith Feemster



3. "Scratch-off" cards instantly recognize safe behaviors and hazards

Freeze protection, Minnesota style

Best Practices Award

Challenge. At a plant located in one of the harshest winter environments in the continental US, personnel are faced with multiple challenges to ensure immediate dispatch availability, especially after being idle during prolonged periods of sustained sub-freezing temperatures.

Originally, the facility included a lot of outdoor equipment—including the gas turbine (GT), the heat-recovery steam generator (HRSG), and several associated subsystems. To further complicate matters, the facility was not equipped with an auxiliary boiler.

Faribault Energy Park

Owned by Minnesota Municipal Power Agency
Operated by NAES Corp

300-MW, dual-fuel, 1 × 1 combined cycle located in Faribault, Minn

Plant manager: Bob Burchfield

Solution. After commissioning the plant in fall 2007, and with winter fast approaching, personnel took a broad-brush approach to address several immediate issues at hand. First, the team recognized the need for a detailed checklist that included sign-off accountability for specific instrument verifications.

The team implemented an "Offline 32 Degree Action Log" (excerpt shown in Fig 1) to guide an operator through every portion of the system to verify non-freezing conditions, such as draining each HRSG drum by a small amount while observing the response of the drum level transmitter. To ensure that non-responsive transmitters were consistently identified, ambiguous wording such as "periodically start pump and monitor for freezing" was removed from the steps.

Next, temporary heaters and tarps were procured for each location that

Offline 32 Degree Action Log					
System	**No. of times per shift**	**Action**	**Operable? Yes/No**	**Date, time done**	**Initial**
Demin	1	Start/cycle STG demin water pumps 513PP-1003A + B and GT demin water pumps 1001 and 1002			
Demin	1	Stroke hotwell level control valves 513LCV-042A + B and ensure that hotwell level 452LIT-042B increases			
BFP	1	Run boiler feed pumps 480PP-1001A + B (alternate pumps each start)			
BFP	1	Verify min-flow recirc transmitter responds to changes in min-flow recirc valve positions 480FIT-162 and 172, respectively			
HP drum	1	Fill drum and verify drum HP level transmitter response 201LT-1801 and 1806 (use both LCVs independently)			
HP drum	1	Verify HP feedwater flow transmitter response 480FIT-178			
IP drum	1	Fill drum and verify drum IP level transmitter response 201LT-1701 and 1702			
IP drum	1	Verify IP feedwater flow transmitter response 480FIT-177			
HP drum	1	Blow down HP drum and verify drum level transmitters confirm blow down (check both startup dump and continuous blowdown)			

1. "Offline 32 Degree Action Log" has contributed significantly to the elimination of freeze-up issues

Team Faribault with Best Practices Award

2. LED lights warn of impending issues in heat-trace circuits

was identified as being more susceptible to freezing.

The team also established a heat-trace testing regime to periodically record individual circuit amperages. A significant drop in periodically monitored supply breaker amperage could be used as an indication of an "open" in one of the heat-trace branch circuits.

Additional heat-trace LED indicating lights were procured and installed (Fig 2), providing an "easy to notice" indication of voltage. These visual indicators are used in conjunction with the amperage monitoring plan as a comprehensive set of troubleshooting data points, allowing for easier and more accurate problem resolution.

Operating under a requirement to maintain HRSG drum levels in a ready-to-start status, and with no auxiliary boiler to provide sparging steam, the team established detailed criteria to determine when the gas turbine was required to be started to prevent the HRSG and associated steam system from freezing. The time between GT starts had to be optimized to limit fuel and starting costs.

To accomplish this, specific HRSG temperatures are trended in conjunction with weather forecasting to determine the anticipated time the plant can be idle before requiring a "HRSG freeze protection" start-up. Interestingly, a detailed return on investment (ROI) analysis did not justify the capital and operational expenses associated with the installation and operation of an auxiliary boiler, because of the uncommon occurrences of extended plant idle periods.

3, 4. Desuperheater station enclosure—outside (left), inside (right)

5. False-start drain enclosure

6. Level control valve enclosure (building add-on)

Long-term freeze protection solutions

7. HRSG blowdown tank pump enclosure

Over time, plant personnel established a list of action items from lessons learned during that first winter to reduce freeze-related events in subsequent winters. In one example, heat-trace testing was scheduled earlier to allow sufficient time for potential repairs before sub-freezing temperatures arrived.

A "pre-winter" freeze prevention plan was drafted with each specific task entered into the computerized maintenance management system. Due dates were set to allow ample time for completing each task before the cold weather arrived. Examples of the plant pre-winter plan include high-level task descriptions, such as:

- Verify all heat-trace circuits and record amperage readings.
- Lay up the evaporative cooler system.
- Begin daily use of the "Offline 32 degree action log."

In all locations where temporary heaters were required, the facility owner and plant personnel designed professionally engineered enclosures to complement the plant architectural scheme (Figs 2-7). Several items were considered during construction such as:

- Is additional heating and ventilation required?
- How much and what type of lighting will be required?
- How can the enclosure be accessed when maintenance is required?

Results. "The devil is in the details," explains the plant manager. "Like our plant, most facilities have a freeze protection checklist. If your facility has struggled with freeze-related outages, review your checklist and ask if it requires the CRO and outside operators to sign off on each check they perform." If your checklist doesn't have that level of detail, he suggests trying the plan implemented above.

In one of the nation's coldest locations, the facility has experienced only one hour of startup delay caused by freeze-related issues in the past four years, primarily because of the detail-oriented checklists, creative engineering system implementation, and the dedication of plant personnel to proactively identify upcoming conditions.

Project participants:
Bob Burchfield, plant manager
Doug Klar, operations manager
Tim Mallinger, lead O&M technician
The entire O&M staff

HRSG chemical feed system improvement

Challenge. To maintain a condensate pH of 9.2 to 9.6, plant operations personnel routinely transfer an amine/ammonia blend containing 40% ammonium hydroxide from a 55-gal drum to a mixing tank where water is added, and then pump that solution into the condensate system. During this process, personnel are exposed to a significant risk of chemical burn or spill because of the portable chemical barrel pump and hose used to transfer the amine/ammonia blend.

Plant personnel conduct approximately 80 of these chemical transfers per year, and the operator must wear a full chemical suit with boots and a face shield when transferring the amine/ammonia blend. Further, because the mixing tank is not fully enclosed, ammonia vapors in excess of 100 ppm create a potentially hazardous breathing atmosphere in both the HRSG chemical feed room and the BFW pump room. Plant personnel must open doors to increase ventilation (Fig 8).

Solution. Plant staff eliminated the process of manually mixing water and chemicals by replacing the existing day tank with a portable 330-gal tote of concentrated product. First, plant staff contracted with an engineering firm to provide an engineered drawing for the containment calculation, and for tank and pump positioning.

Next, plant staff contacted the chemical provider to supply a 330-gal self-contained tote, and to provide specifications for the new pumps required for the higher mix ratio, as the amine/ammonia blend would no longer need to be mixed with water.

Finally, the team sent out a request for quote to several contractors for the purchase and installation of the stainless steel containment, a tote stand, and pump stands. The team successfully implemented a fully contained amine/ammonia porta-feed system (Fig 9).

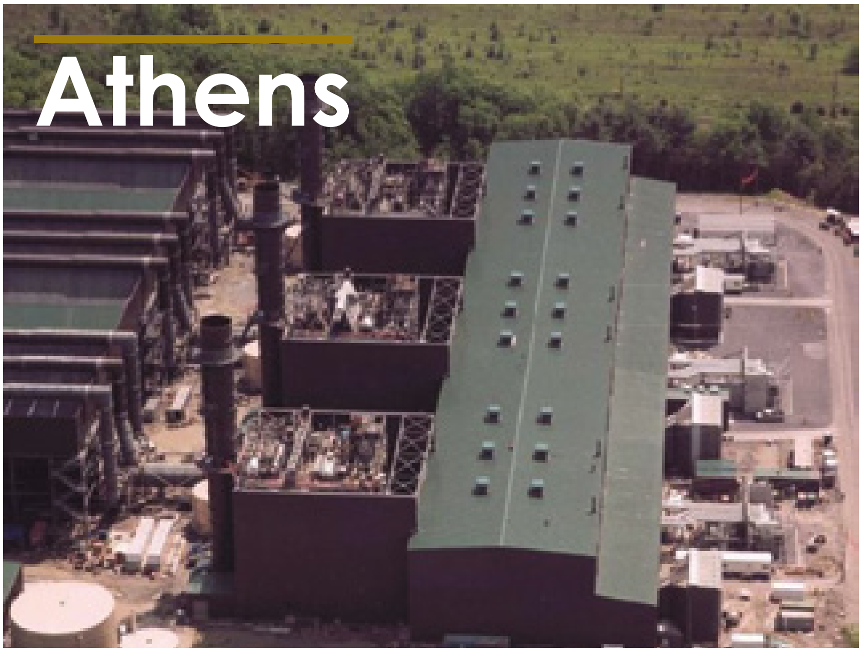
Results. After performing this modification, the plant noticed several advantages to the new amine/ammonia porta-feed system. Some of the more important advantages include:

- Completely eliminated the hazardous atmosphere created by mixing the chemical in an exposed tank.
- Improved the accuracy of chemical dosing by eliminating the step of blending the chemical with water.
- Significantly reduced the likelihood of a chemical burn or spill by eliminating the need to transfer the product with a portable barrel, pump, and hose.
- Significantly reduced the likelihood of a chemical burn or spill by changing the number of chemical transfers from approximately 80 per year to a single, annual change out of the tote, which is performed by the chemical provider.

Project participants:
Doug Klar, operations manager
Tim Mallinger, lead O&M technician
Shawn Flake, I&C technician
Matt Murray, I&C technician
Bob Flicek, mechanic

8. HRSG chemical-feed system as originally installed

9. Re-engineered system improves health and safety aspects of handling chemicals



Detecting pump issues before they cause outages

Best Practices Award

Athens Generating Plant

Owned by New Athens Generating Co LLC
Operated by NAES Corp

1080-MW, gas-fired, three 1 x 1 combined cycles located in Athens, NY

Plant manager: Dan DeVinney

Darron Pruitt

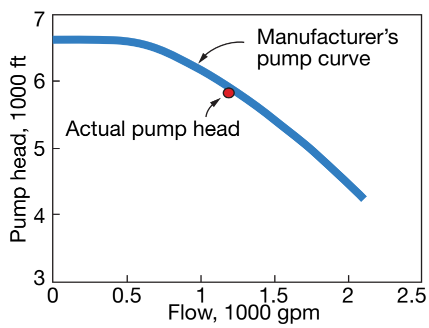
Challenge. Athens Generating Plant was designed without redundant boiler feed pumps, condensate pumps, or closed cooling-water pumps. The failure of any one of these critical pumps could lead to an extended forced outage. The challenge for the plant was to minimize the possibility of a forced outage caused by the loss of an unspared pump.

Solution. To address this challenge, plant staff implemented a pump monitoring program to detect and predict equipment issues before they result in unit downtime. The goal is to ensure pump reliability for the non-redundant pumps.

The pump monitoring program consists of five practices that assess pump condition:

1. **Performance.** Performance is continuously monitored by comparing real-time operating characteristics to design curves. Real-time pump conditions are plotted against the manufacturer's data to determine if the unit is performing as expected.
2. **Pump modeling.** Performance pump capacity surveys are taken biannually to ensure the pumps are operating according to the manufacturer's "pump curve."
3. **Vibration analysis.** Regular vibration readings are taken to ensure that there is no increase in vibration. Vibration analyses are conducted monthly or bimonthly.
4. **Thermography**. Scan the pump motors using thermography to check for hot connections or arcing.
5. **Daily inspections.** Daily pump inspections ensure there are no abnormal leaks or noises during normal operations.

Results. These techniques have given the plant the ability to identify abnormal pump operating characteristics and pump degradation, helping plant staff to quickly recognize problems with critical non-redundant pumps. For example, the plot shown in the figure indicated that the boiler feed pump was not operating at the best efficiency while at base load. As such, this boiler feed pump will be replaced during the upcoming annual outage, prior to failure.



Regular monitoring revealed pump was not operating at the best efficiency point while at base load

Project participants:
Hank Tripp, plant engineer
Tom Birk, maintenance planner

Severe-storm, tornado readiness key to personnel safety

Best Practices Award

Tenaska Kiamichi Generating Station

Owned by Kiowa Power Partners LLC
Operated by Tenaska Operations Inc

1220-MW, gas-fired, two-unit, 2 × 1 combined cycle located in Kiowa, Okla

Plant manager: Bob Pope

Challenge. Severe storms and tornados can pop up on short notice in Oklahoma. Kiamichi procedures call for actions to be taken as storms/tornados are tracked from 50 miles out—including making preparations to shut down the plant if necessary. All personnel must be notified of a severe storm in the area of the plant in a timely manner.

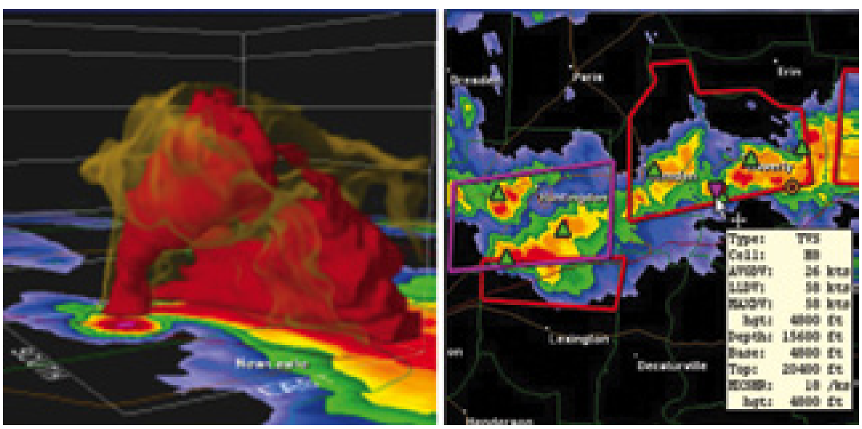
To achieve this goal, Kiamichi needed to receive and monitor real-time data on storm severity, speed, and direction 24/7/365. The plant is located on the outer edges of the areas covered by major TV stations: Dallas is about 3 to 3.5 hours away, Oklahoma City 3 hours, and Tulsa 2.5. These stations provide little coverage of weather in the area of the plant; rather, they pan the weather highlights in areas where most of their viewers live. Consequently, TV is of little value for providing the detailed weather information required by the plant. Likewise, most weather Internet sites are of limited value because the information they deliver typically is 10 to 15 minutes old by the time it hits the screen.

Travis Williams

Solution. Stationary and portable weather radios were purchased and located in the control room. They are removed when evacuating to the storm shelters (Fig 1) and each shelter has a radio for monitoring the storm. As for weather information, the plant subscribed to Gibson Ridge, which offers radar data along with software that allows the plant to view storms in its area in real-time (Fig 2). Having the ability to see weather in real time and know how fast and severe a storm is coming towards the plant greatly improves the decision-making process.

The plant also purchased and installed three sirens to alert of severe weather. They are located around the plant and are started from the control room by the operators. Sirens are sounded when severe storms are less than 30 minutes/25 miles out and tracking towards Kiamichi. When the sirens sound, all plant personnel gather in the control room for weather updates and instructions.

1. Storm shelters protect plant staff and visitors during severe weather



2. Weather service and special software allow the plant to view storms in real time

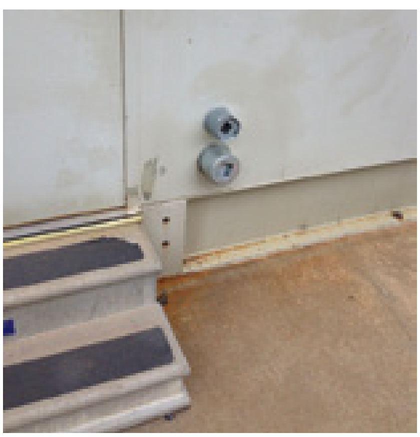
Results. Installation of weather monitors in the control room and plant lobby, sirens, weather radios (stationary and portable), storm shelters (already installed), and coordination with the local emergency planning committee has produced the capability for making decisions and preparations for severe storms with real-time information even on short notice 24/7/365.

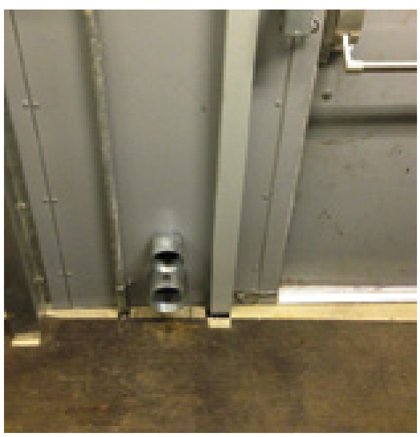
Project participant:
Travis Williams, program and projects specialist

NERC CIP-006: physical security perimeter challenges

Challenge. North American Electric Reliability Corp's (NERC) standard CIP-006 requires continuous physical security of the perimeter surrounding Critical Cyber Assets.

Kiamichi's annual performance test presented a challenge in that cabling for temporary instrumentation would need to be run into some of these protected areas for an extended period of time. Leaving the doors to the secure areas open for this cabling would have made us non-compliant with the security requirements of the standard.





3, 4. Penetrations allow temporary cabling to pass through walls (outside view at left, inside at right) without violating the secure-perimeter requirements of NERC CIP-006

Solution. Following discussion of options, the decision was made to add permanent access points for this cabling that could be reclosed upon completion of testing (Figs 3, 4). The I&E department installed permanent penetrations with threaded plugs in the walls to allow the cabling to pass through the building walls. When testing is not on-going, the threaded plugs are installed to keep the areas closed to the elements. The penetrations are large enough to handle the cabling required for testing but small enough that there is no possibility of causing a security concern.

Results. The secure area doors remain closed and secure at all times while still being able to perform the competing operational requirements of performance testing.

Project participants:
Robert Bell, plant engineer
Rusty Clark, I&E technician

Student internship program helps combat aging workforce

Best Practices Award

Crockett Cogeneration

Owned by FREIF North American Power I LLC
Operated by Consolidated Asset Management Services

250-MW, gas-fired, 1 × 1 combined-cycle cogeneration facility located in Crockett, Calif

Plant manager: Adam Christodoulou

Challenge. Crockett Cogeneration has had a student intern program in place since 1999, and primarily has selected its engineering students from the California Maritime Academy, CSU. Students typically are hired when they are freshmen or sophomores, and they remain in the internship program until they graduate. Interns are allowed to schedule their working hours around class schedules, and then commit to working full-time during summer and winter breaks.

Solution. The plant, in conjunction with CMA, helps to train student interns in all facets of powerplant operations, maintenance, and facility management. The students are required to submit written reports to their professors on subject matters learned while interning to receive academic credits. Partnering with California Maritime Academy has been very beneficial to Crockett. We are provided with quality men and women who take their studies and career development seriously, and in return, interns are able to contribute meaningful work experience in the classroom.


Chris Sargent

Throughout the years we have continually worked on developing a credible internship program, and today we have a formal training program in place which tracks the progress of our interns in all functions pertaining to plant operations, maintenance, and management issues. The internship training program includes, but is not limited to, safety and environment, plant systems and equipment, and water chemistry.

Interns first become familiar with our safety and environmental programs, and eventually receive enough training to perform the duties of an outside operator and board-qualified operator. Through the years, interns work alongside members of our operations staff to perform routine preventive-maintenance work orders and safety walkdowns. Interns also learn to manage the CMMS system by taking ownership of the annual inventory count. They provide services during outages—such as performing hole watch duty for confined spaces, assisting with receiving materials, and facilitating the movement of contractors in and out of the plant.

While on the job, interns provide a service to our entire staff. All employees at Crockett Cogen have direct involvement in the interns' on-the-job training and are rewarded with a sense of pride when the interns are nearing graduation and start the employment process.

Results. Upon graduation, many of the interns go on to find careers in the power industry. In the past 10 years, two graduates have secured jobs with General Electric as field engineers, one is working for GE as a water-quality technician, and five are working as plant operators. Crockett hired three of those interns as plant operators. The number of graduating interns is too high to account for all of them, but there is no reason to doubt that they went on to become successful in their chosen career paths.

From the perspective of a plant manager, student interns offer new and varied perspectives on equipment and systems and tasks that have become routine. Interns learn, but so do the employees. The project-based interactions with enthusiastic learners is a rewarding and a meaningful experience for all.

Project participants:
Adam Christodoulou
Dave Poling
Chris Sargent

Harquahala

Safe practices for inspecting, maintaining cooling towers

Best Practices Award

New Harquahala Generating Co LLC

Owned by MachGen Holdings LLC
Operated by NAES Corp

1080-MW, gas-fired, three-unit, 1 × 1 combined cycle located in Tonopah, Ariz

Plant manager: Dean Motl

Challenge. New Harquahala personnel routinely inspect and maintain the gearboxes, fans, fill, and structure for the facility's mechanical-draft wet cooling towers (photo). This work is demanding, beginning with the rigorous effort required just to get inside the tower's 18 cells—starting with confined-space requirements. But the biggest challenge was how to tie off and keep personnel from falling and contacting the structure and fill located 8 ft below the fan deck.

Dean Blaha

Plant personnel concluded that tie-off points on the fan-blade assembly or gearbox would not give personnel the adequate free fall distance to fully expel the deceleration devices on lanyards, regardless of the rigging configuration. Additionally, there is not a suitable tie-off point above the fan assembly to connect the lanyard that would support the OSHA capacity requirement, or increase the free-fall distance.

The first solution was to revert to the original plant practice of using a crane as a tie-off point during minor maintenance and inspections. During a major overhaul—such as a gearbox replacement or fan-blade replacement—the facility would have a scaffolding deck built around the full perimeter of the top deck of the cell at a cost of $7500 per cell.

However, recent changes to the plant's fall protection program eliminated the ability to use the crane, and plant personnel were challenged to find a prudent and cost-effective means for tie off when conducting maintenance and/or inspections.

Many different options were investigated—from monorail systems to an engineered cable system—but none was cost-effective. So, the objective to establish the ability to safely execute maintenance and/or inspections in the facility's 18 cooling tower cells was still on the table.

Solution. Plant personnel reached out to their approved cooling-tower repair contractors and identified an engineered platform that was both cost affective and eliminated the use of fall protection entirely. Adhering to the facility's annual budget, plant personnel recognized that the cost of installing the scaffolding in each cell was equivalent to purchasing a permanent platform.

The facility has purchased and installed this platform on one of the cooling-tower cells and plans to inventory one that will be installed during the next major maintenance project. The plant will install the permanent platform on the remaining cells during the next major maintenance evolution.

Results. Plant personnel can now conduct maintenance and inspections safely inside the cooling tower cell with a cost-effective upgraded platform.

Project participants:
Dean Motl, plant manager
Chris Bates, maintenance manager
Brad Miller, O&M technician

Two mechanical-draft cooling towers, nine cells each, serve the three 1 × 1 G-class power blocks at New Harquahala

New, safer method of rigging halves time for ACC gearbox change-out

Best Practices Award

Walter M Higgins Generating Station
NV Energy Inc
530-MW, gas-fired, 2 × 1 combined cycle located in Primm, Nev
Plant regional director: Tom Price

Challenge. Walter M Higgins Generating Station has a 40-cell Hamon air-cooled condenser (ACC) with 34-ft-diam Howden fans. The Flender gear reducers are driven by Teco-Westinghouse two-speed, 200-hp motors.

When changing an ACC gear reducer, the hub and blade assembly usually is disconnected as a unit and held in position by rigging and come-alongs or chain falls. Such rigging work can be a challenging process with safety implications. Fact: Rigging to the fan blades/hub assembly is never straight, in-line, or perpendicular to anything because of the nature of the equipment and structure.

During the installation of the new or replacement gear reducer, aligning the fan hub assembly to the gear reducer hub is difficult at best (Figs 1, 2). Since the rigging and come-alongs/chain falls are not directly supporting the assembly, adjusting any of them results in the assembly moving in strange ways.

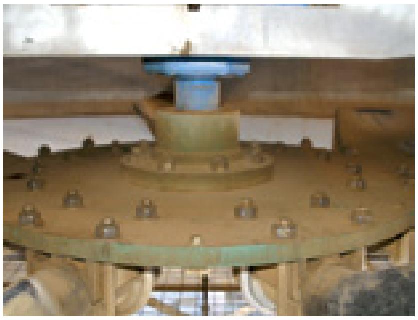
Tom Price

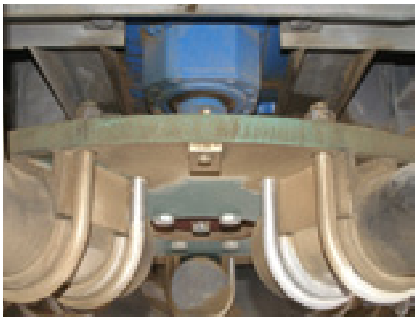
Solution. After much discussion and several gear-reducer changes, the mechanical maintenance crew determined there had to be a better way to hold the hub and blade assembly to facilitate replacement (Fig 3). A basic design was drawn up and presented to NV Energy's corporate engineering staff for review. After the design was finalized and engineered for safety and load, the project was handed out for fabrication.

The plant's concept was simple and direct. Two cross members fit into the structural elements of the fan bridge and lock down with high-strength "C" clamps. Four 1¼-in. B-7 alloy high-tensile-strength all-thread rods drop down into the cross beams to hang over the hub plate (Fig 4). Four custom-designed clamps fit onto the hub plate and clamp securely to the plate, while the all-thread rods are through-bolted to the clamps and tensioned (Fig 5). The nuts on the top cross beam are then tensioned as well, locking the whole blade assembly in one position.

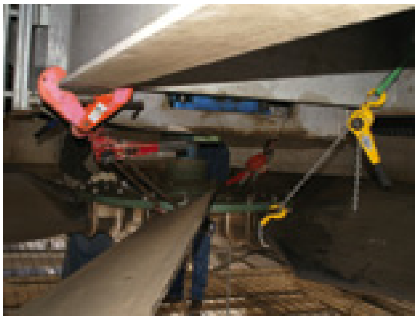
The gear reducer is then unbolted and removed. The fixture is now holding the entire blade assembly securely and stable (Fig 6). Once the new or replacement gear reducer is dropped into position it is a simple matter of turning the input shaft to align the bolt holes on the fan hub assembly.

Note the center eye bolt in Fig 7.





1, 2. Fan hub assembly and gear-reducer hub are shown from the top at left, from the bottom at right



3. Old method of rigging and holding the fan assembly

4. Cross beam and high-strength all-thread rods in position

It is for the chain fall that actually removes the gear reducer from operating position and takes it outside for transfer to ground. The arrangement of eye bolts gives a clear and safe way to change from one hoist to another, without binding, confusion, or risk of rigging failure. Since the fan assembly has not moved at all during the gear-reducer change, it becomes a very quick, safe, and easy job.

Results. The fixture saved approximately two hours the first time it was used to change a reducer. There was a strong up-draft through the ACC cell during the change out and the fixture held firm and didn't wobble or twist at all. In fact, in adjoining cells the fans were being turned by the wind

5. Fan hub clamp in position (left)

to equivalent high rpm.

In conjunction with the gear-reducer fixture the entire gear-reducer change-out time has been reduced from a two-day event (working day shifts only) or about 20 hours, to a single 10-hr day job. The gear-reducer fixture increased safety and improved rigging height issues for removal of reducer from the fan deck of the ACC as well.

6. Fan hub assembly is held only by the hub fixture. Note that the loose bolts were put in a bucket and removed from the area right after this picture was taken

7. Center eye bolt for the chain fall facilitates handling of the gear reducer

Project participants:
Dave Cairns
Dave Rettke
Jeff Smith

Jimmy Jeong

Preparing plant, workforce for hurricane conditions

Best Practices Award

Bridgeport Energy

Owned by Capital Power Corp

520-MW gas-fired 2 × 1 combined cycle located in Bridgeport, Conn

Plant manager: John Klopp

Challenge. Natural disasters pose unique problems to both labor and equipment. The impact to employees is twofold: How do they respond both to the needs of the facility, and to their personal lives? The challenges associated with the preplanning for a hurricane or severe storm include lack of experience in these events, review and implementation of lessons learned, as well as evaluation and determination of how best to return equipment to service.

Solution. Capital Power's Bridgeport Energy has endured two recent notable storms, Hurricane Sandy (2012) and Hurricane Irene (2011). Aside from the impact to the facility, described later, these storms also negatively impacted employees: One lost power for a total of 14 days following the storms.

The decision between work and family can be very challenging, and to ease that reality, management has taken steps to ensure that employees' homes and families are taken care of while they are at work. For example, the locker rooms were opened to families who needed showers, portable generators were loaned to employees who needed them, and survival bags were stocked onsite for all employees in need.

With these actions, the facility was able to remain fully staffed during all of the events. Since the storms, an additional generator was purchased to have onsite in case the need arises to ease the burden on employees torn between home and work.

There were only a few individuals on staff who had coastal power generation experience and had been through a hurricane. Their input was clear, concise, and to the point—for example, "We need to clean the switchyard bushings." This was a lesson learned from another facility that was restarted after Hurricane Gloria in 1985. The facility had to immediately shutdown because of arcing and tracking caused by salt accumulation on the high-voltage (HV) bushings.

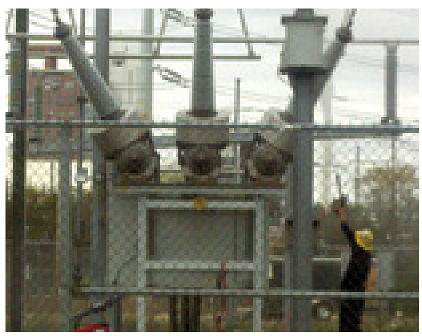
Scott Sargent

Although the statement was very clear, it had a deeper meaning. That was to review systems with a critical eye, aimed at ensuring they are fit for service prior to bringing the unit back online.

For this reason, we took care in preplanning to look at our systems and which ones could be negatively impacted. We developed a robust checklist that incorporated the contracting of companies to come in for high-probability events—such as cleaning HV bushings, cleaning up storm debris left in the plant, and cleaning of the facility's cooling-water trash racks.

Also included in preplanning was a risk assessment where it was determined to shut down and properly secure systems prior to the storm to limit equipment damage. To put the storms into context, the site and surrounding areas were subjected to severe flooding, and although our plant equipment remained above water, the water came within a few inches of entering the control room. Following the storm, the facility was successfully returned to service after the inspections and maintenance activities were completed by both contractors and plant employees.

We had prepared for Hurricane Irene through proactive meetings and checklists which we found to be highly successful, but during our post-storm review of the incident, we found several areas for improvement. The most glaring lesson learned from Irene was that we needed to order a portable back-up diesel/generator in advance to power our critical systems in the event of a station blackout and loss of DC power. Prior to Irene we did not know what size generator to use, which resulted in a prolonged



1. HV bushings are cleaned following the storm to remove salt deposits conducive to arcing and possible unit trip

Natural-gas blowdown system assures a safer working environment

Terry Bundy Generating Station

Lincoln Electric System

175-MW, gas-fired, 3 x 1 combined cycle located in Lincoln, Neb

Plant manager: Brad Hans

Challenge. NFPA-56, "Standard for Fire and Explosion Prevention during Cleaning and Purging of Flammable Gas Piping Systems," required improvements in what had been generally accepted design and O&M practices for natural-gas supply systems. Action was motivated by several deadly gas-line explosions—one at the Kleen Energy Power Plant, a 2 × 1 F-class combined cycle in Connecticut, while it was made ready for commissioning activities.

Solution. At Terry Bundy Generating Station, a remotely operated isolation valve is installed on the gas line in the plant's metering station. In the unlikely event of a natural-gas leak in the plant's distribution piping, the isolation valve would be closed to stop gas from flowing into the plant. However, there is a significant amount of distribution pipe charged with 690-psig gas downstream of the valve. The main concern is that a gas leak within a GT enclosure would continue to charge the enclosure with gas even if the isolation valve were closed.

To reduce this potential hazard, a remotely operated blowdown system was installed just downstream of the main isolation valve. If a leak were to occur, this system would allow the control-room operator to initiate the safe release to atmosphere of gas stored in the plant's distribution system. A 4-in.-diam vent line equipped with a plug valve was installed. A Shafer™ operator uses 120-Vac to allow stored hydraulic pressure to open the plug valve. Alternatively, plant personnel can use a hand pump to increase the hydraulic pressure for opening the valve.

Project participants:
Brad Hans, plant manager
Dan Dixon, LES project engineer

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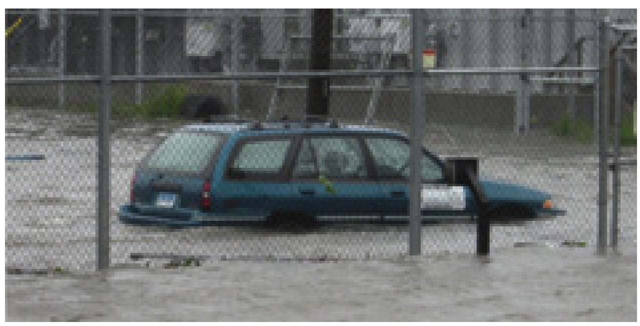
delivery lead-time. For this reason, although preps were made, we still limited our set-up time.

For Hurricane Sandy, proper implementation of lessons learned eliminated this past shortcoming and the generator was the first item ordered; in fact, set-up was completed two days prior to the storm. We have since continued to improve on our preparedness for these types of natural events. One improvement was to incorporate new processes from our lessons learned into the plant's Emergency Site Plan. This ESP upgrade will ensure future staffing has the right tools to safely and efficiently manage future events.

Results. The operations department was fully staffed for both Irene and Sandy and there were no subsequent call-outs after the storm. Also there was one maintenance employee who volunteered to come in on the overnight during Hurricane Sandy.

There were only two days of outage time for the facility; this was due to preplanned inspections and clean-up performed after Hurricane Sandy. The facility remained dispatchable throughout Hurricane Irene.

Project participants:
John Klopp, plant manager
Scott Sargent, production manager
Nicholas Volturno, maintenance manager
Bridgeport O&M staff



2. Clean-up of debris required help from a contractor (left)

3. Flooding caused by Irene came within a few inches of entering the control room (above)

Lindsay Hill

Cooling-tower automated basin temperature/two-speed fan control

Best Practices Award

Tenaska Lindsay Hill Generating Station

Tenaska Alabama Partners LP

845-MW, gas-fired, 3 × 1 combined cycle located in Billingsley, Ala

Plant manager: Robert Threlkeld

Challenge. Control-room operators historically have managed cooling-tower basin temperature by evaluating ambient and basin temperatures. Efficiency of operation and icing issues were the major factors driving this type of control. However, results varied depending on each CRO's individual judgment of conditions. The result was lack of consistency, excessive electrical load, and excessive sub-cooling in the condenser.

Robert Threlkeld

Solution. Tenaska Lindsay Hill Generating Station installed logic control blocks for the cooling-tower fans. These control blocks start and stop the fans using hotwell temperature. Fans are started, operated at high or low speed, and shut down based on hotwell temperature. The fans start on different sides and quadrants of the cooling tower depending on MCC loading. The plant also added a function to start and stop all of the fans in sequence with one command on the HMI screen. This function aids the operator during plant starts and shutdowns.

Results. Control of cooling-tower fans now is fully automated. The set point for the hotwell does not vary outside of the control limits unless there is a system upset or equipment failure. This has resulted in consistent control of fans and hotwell temperature. Benefits include heat-rate improvement and optimal distribution of ancillary electrical load.

Project participants:
Eric Powell, lead control-room operator
Jason Gladden, I&E technician
Claude Couvillion, O&M support
Mark McKenzie, operations manager
Robert Threlkeld, plant manager

Removable platforms in cooling-tower fan shrouds improve safety

Challenge. Multiple times annually, plant personnel must enter the cooling-tower fan shrouds to inspect gearboxes, obtain oil samples, service fan blades, and perform corrective maintenance. Funding is budgeted annually to have walk boards, tag lines, scaffolding, and handrails installed to safely access the work locations for all 14 fan cells.

Solution. The plant purchased four removable fiberglass platforms and handrails. A vendor installed the support hardware for the platforms in all 14 cells. This system allows plant staff to move and install the platforms in any of the 14 locations for maintenance activities. This operation is very safe and straight forward. Personnel are not required to use a harness or tie off during the installation or work on the platforms.

Results. Since installing this system, personnel have safely entered the 14 cooling-tower shrouds multiple times. Installation of the platforms promotes quick and efficient correction of issues. Time and money have been saved because there is no need for scaffolding or other means of safe access.

Project participants:
Robert Wimberly, maintenance technician
Vince Crabtree, maintenance manager
Mark McKenzie, operations manager
Bill Buster, plant engineer
Robert Threlkeld, plant manager

Osprey

Osprey Energy Center

Calpine Corp

600-MW, gas-fired, 2 × 1 combined cycle located in Auburndale, Fla

Plant manager: Steven Smith

Start faster, earn more

Best Practices Award

Challenge. In order to reap the benefits of favorable grid economics, Osprey Energy Center improved its cold-start performance to ensure 40-min starts. Site personnel investigated the possibility of a 40-min ramp cycle (0-250 MW) for a combined-cycle unit and explored the timing requirements and key steps to achieve a fully blended and ready-for-market response status.

Solution. Plant staff reviewed HRSG heat-up limits as well as steam-turbine (ST) warmup restrictions and worked with the OEMs to optimize the startup process to bring the plant from shutdown status to a 2 × 1 ready for all market calls within a 40-min window (Fig 1). By bringing indication of HRSG drum heat-up rates to the DCS, and optimizing ST starting logic, the site was able to achieve its first 40-min 2 × 1 ramp in March 2012.

During the March start, a demonstration of operator manual control requirements lead to the addition of a split-range HP-to-auxiliary steam letdown control valve to reduce the operator commitment to maintaining steam header pressure (Figs 2, 3). The addition of split-range control permitted the operator to focus on plant response to operational requirements and allowed for smoother control of auxiliary header pressure (air ejectors).

Results. Successful and reliable cold starts from 0 to 2 × 1 ramp in 40 minutes.

Project participants:
The entire Osprey plant staff

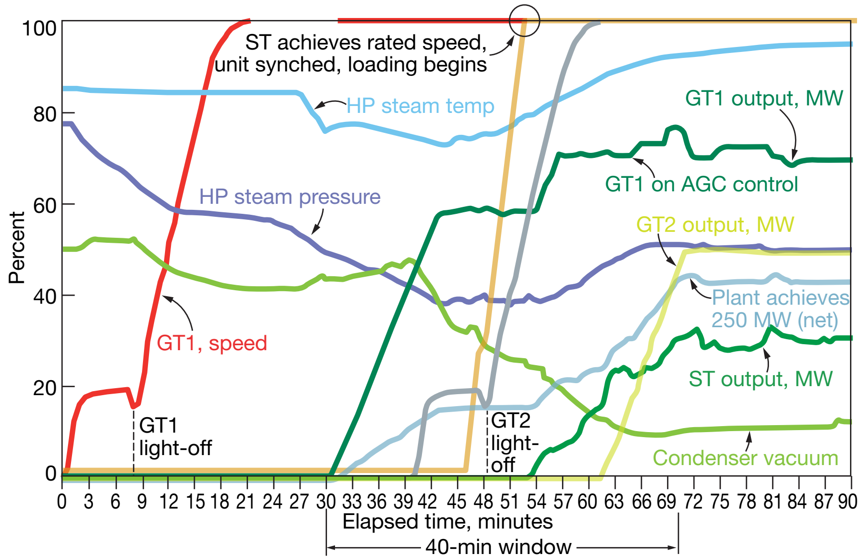
Seasonal readiness refresher training

Challenge. By providing preseason refresher training on systems, industry and company lessons learned, and improving system indications, O&M personnel have a renewed level of knowledge on systems that are infrequently operated.

Solution. Preseason refresher training on heat tracing and freeze protection renews O&M staff level of knowledge in advance of any cold weather. By the inclusion of system and theoretical basics into lesson plans, trainees renew their level of knowledge from the ground up. Having this training as an interactive session with the participants, and not solely a lecture, maintains a high level of involvement.

The addition of indications in the heat-trace system, including panel schedules on controllers as well as "per phase" load indications give the operator information on which lines

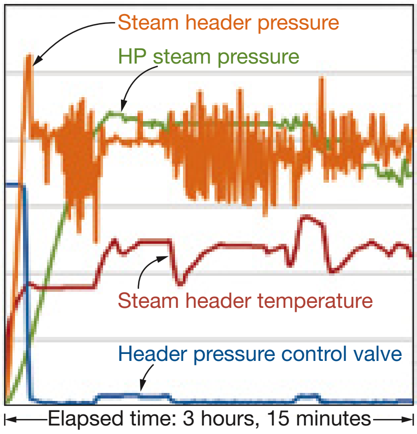
Tom Barnes (left) and **James Guevara**

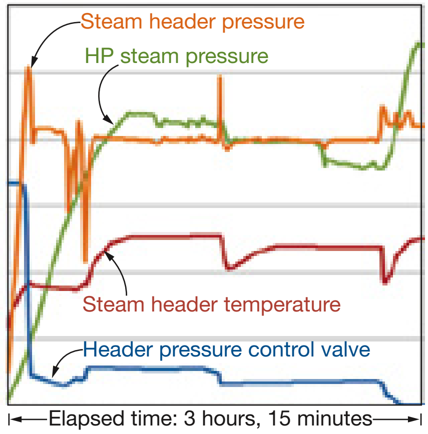


1. Osprey personnel optimized the plant's startup cycle to make it ready for market calls within a 40-min window are protected and how the protection system is functioning.

Results. The plant has experienced zero heat-trace -related failures since program implementation.

Project participants:
Steven Smith, plant manager
Gil Kaelin, maintenance manager





2, 3. Wide fluctuation in header pressure (right) was eliminated by installation of a split-range HP-to-auxiliary steam letdown control valve (far right)

How Best Practices entries are judged

Objective judging is critical to the success of any awards program. The CTOTF™ Leadership Committee, chaired by Bob Kirn of Tennessee Valley Authority, selected from its ranks a panel of 10 judges for 2013. Note that Best Practices entries were scrubbed of company, plant, and personnel names before they were submitted for judging.

Entries were received from gas-turbine-based combined-cycle, peaking, and cogeneration plants. The panel of judges reflected expertise in each of these sectors of the industry to ensure a level playing field for all participants. Here's a thumbnail sketch of the panel's qualifications:

- One judge is an active plant manager.
- The remaining nine judges are attached to their companies' headquarters sites and have engineering and/or management responsibilities for multiple generating resources.
- All of the judges operating out of headquarters locations are former plant or O&M managers at generating facilities powered by gas turbines; several have conventional steam-plant experience as well.
- Plant management/operations experience of the panel is well over 200 years.

Each judge received a notebook containing both the entries and a score sheet. The categories selected for 2013 by a joint CTOTF/CCJ working committee encouraged entries pertinent to industry-wide initiatives. They are:

- Fast starts.
- Natural-disaster preparedness and recovery.
- O&M electrical—including generators and transformers.
- O&M mechanical—including major and BOP equipment.
- Outage management.
- Performance improvements.
- Plant safety procedures.
- Workforce development.
- NERC CIP V.4 compliance.

The assignment: Read each entry for a given category and rate it from 1 to 10 for the five evaluation parameters listed below—10 being the best. The weighting factor assigned to each evaluation parameter is in parentheses.

1. Achieved business value—both real and measurable (weighting factor of 10).
2. Complexity of the issue (8).
3. O&M staff involvement (6).
4. Degree of coordination across multiple groups at both the plant and corporate levels (5).
5. Duration of the value proposition (9).

Next step is to multiply the score for each parameter by its weighting factor; then add the results. Each judge submits his or her rankings to the editors, who then compile the results.

Another change in the program implemented by the working committee this year was to recognize Best of the Best (BOB) recipients on the basis of points across all entries rather than by category, as had been the practice. The result: No BOBs were awarded for plant safety procedures, outage management, O&M mechanical, and natural-disaster preparedness and recovery, although several plants received Best Practices plaques in each of those categories.

You be the judge

By the time you get to this segment of the Best Practices Awards special section hopefully you've at least skimmed all of the entries and read through, and benefitted from, a couple that were of particular interest. If you have been associated with the GT-based sector of the industry for a few years, your reaction to several entries might be the following: "We did that a couple of years ago." You might also add: "And we did it better." And if that's true, you probably have continued to innovate and have ideas that your colleagues would find valuable. Please consider participating in the 2014 Best Practices Awards program (instructions at www.ccj-online.com/best-practices).

To better gauge how your entries might be rated, consider evaluating the 2013 entries and see how the results compare with those of the judges. The score sheet below is helpful in this regard.

Submittal		Business value Score	×	Wt	+	Complexity Score	×	Wt	+	Staff involvement Score	×	Wt	+	External coordination Score	×	Wt	+	Duration of value Score	×	Wt	=	Total score	Rank
Entry	1		×	0	+		×	8	+		×	6	+		×	5	+		×	9	=		
Entry	2		×	10	+		×	8	+		×	6	+		×	5	+		×	9	=		
Entry	N		×	10	+		×	8	+		×	6	+		×	5	+		×	9	=		

TermoemCali

Well water, bypasses, new procedures eliminate debris issues on plant starts

Best Practices Award

Challenge. The steam-condenser cooling system, which draws water from the Cauca River, includes three vibrating screens to prevent waste material from being sucked into the plant by the main circulating-water pumps. These screens are continuously pressure-washed using water from the auxiliary cooling system, which also sources water from the Cauca River.

The eight spray nozzles delivering wash water to each screen frequently clogged with sand or waste material, allowing debris to overload the screens. Other system hardware also got clogged with debris, including redundant plate-and-frame heat exchangers A and B which transfer heat from the closed cooling water system (CCW) to the auxiliary cooling water (ACW). Fouling occurred at every startup, causing delays in running plant equipment, because the main circ-water pumps could not be operated using dirty water without causing equipment damage.

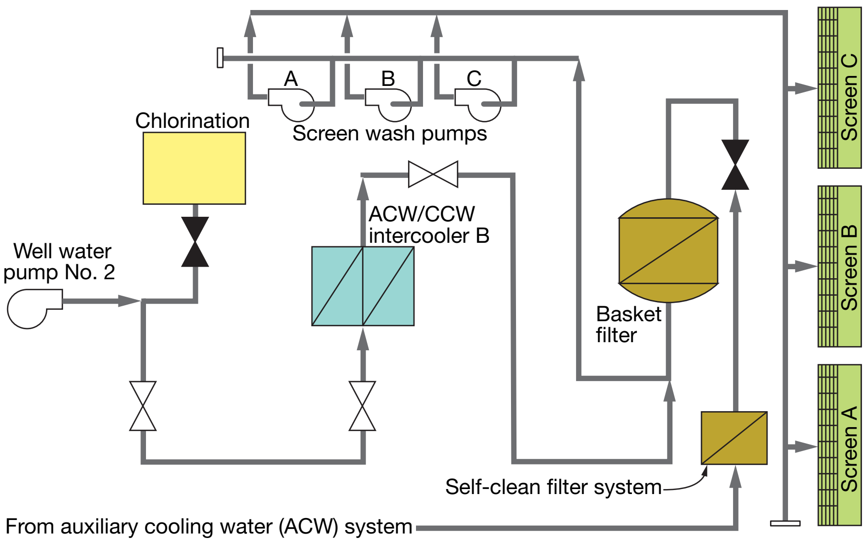
Maintenance personnel frequently had to clear or change the spray nozzles, clean the screens, and wash the heat exchanger plate by plate. These tasks could take two days or more, leaving the plant vulnerable with only one operable ACW/CCW intercooler—the plant's name for the plate-and-frame heat exchangers.

Moreover, before each startup, plant staff had to clean the condenser interior (confined space work), a task that required three people. All of this manual cleaning was strenuous, took a long time, and required work permits, lock out/tag out, etc.

Solution. The solution was to find a clean source of water for the nozzles, at least for the first few minutes following a plant start, when most of the debris that had pooled at the inlet with the plant out of service was sucked into the circ-water system. Personnel decided to pump water from the plant well, which required the team to modify the system as follows (Fig 1):

- Install a derivative line with an isolation valve from the No. 2 well pump to ACW/CCW intercooler B.

Team TermoemCali



1. Clean well water is used to wash inlet screens at startup, preventing the fouling of spray nozzles and other equipment

TermoemCali

Owned by ContourGlobal Latam SA
Operated by NAES Corp

250-MW, dual-fuel, 1 × 1 combined cycle located near Cali, Colombia

Plant manager: Adier Marin

- Install a connection, with an isolation valve, to the main ACW pipe entering intercooler B.
- Install a bypass line and valve between the circ-water inlet and outlet lines serving the condenser.
- Create a written operating procedure for the revised system.

Today, with the ACW system out of service during the first few minutes of operation following a plant start, well water is delivered to intercooler B to cool the CCW. In the pump house, well water is used to wash the screens, preventing them from being clogged with debris. And the circ-water pumps are started with the bypass valve open and water received from the river is returned to the bay without flowing through the condenser.

When river water is considered suitable for plant use, personnel put the ACW system into service, shut down the well pump, and close the circ-water bypass valve, allowing river water to flow through the condenser.

Results. The modifications outlined above have had several important benefits:

- The nozzles used for washing the screens no longer clog, contributing to faster plant startups.
- In 2012, the plate-and-frame heat exchangers did not require disassembly for cleaning; previously, they were cleaned quarterly.
- Adding the circ-water bypass valve ensures that clean water is supplied to the condenser, eliminating the need to clean that heat exchanger before each startup.

The total cost of these system modifications was less than $5000. The maintenance cost savings for the first year alone was more than 10 times that amount.

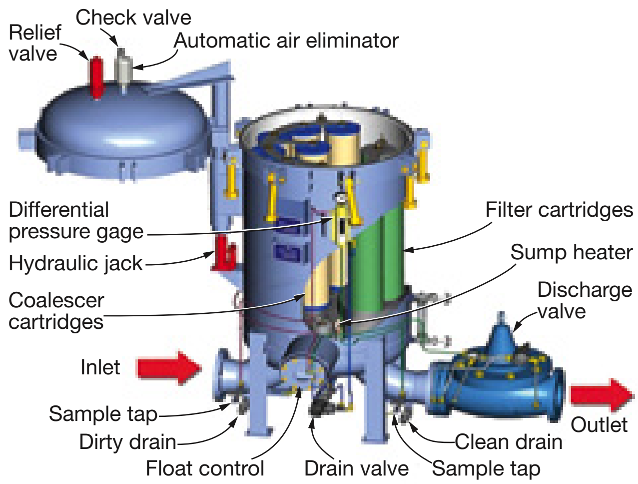
Fuel-tank retrofit helps preserve biofuel

Challenge. By order of the Ministry of Environment and Sustainable Development in Colombia, starting Jan 1, 2013 all suppliers, consumers, and warehouses must use No. 2 fuel oil containing (1) less than 50 ppm of sulfur and (2) from 2% to 8% (vol) of biofuel.

Biofuel is highly hygroscopic (attracts and holds water) and has a relatively short "shelf" life. The main fuel tank at the plant—with a capacity of 1,375,000 gallons, a fixed roof, air and moisture vents, and an overflow pipe—was not optimal for storage of biofuel.

Solution. To prepare for the use of biofuel at the plant, staff completely drained and cleaned the inside of the storage tank and then refilled it with spec distillate blended with 2% biofuel. To prolong the quality of the biofuel during storage, the team took several measures to reduce the fuel's exposure to air and remove as much residual moisture from the tank as possible. These measures included:

- Adapted a 600-gpm casing to accommodate coalescing filters.
- Designed the tank to recirculate the biofuel monthly to remove excess moisture.
- Installed the 400-gpm system in



2. Oil in storage is recirculated monthly to remove water and particulates (above)

3. Submicron filter and humidity extractor for vent and overflow lines help keep tank clean and moisture-free (right)

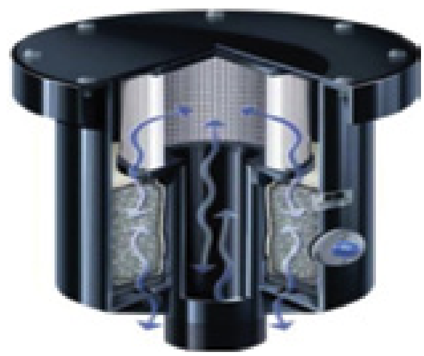


Fig 2 with coalescing elements and sub-5-micron filters through which the biofuel is recirculated monthly.

- Modified the recirculation system to minimize the exposure of fuel to air. Now, biofuel pulled from the bottom of the tank is returned to the floating suction at the top of the tank. This way, the biofuel never returns through open air in the upper part of the tank.
- Installed in the overflow and vent pipes a special submicron filter and humidity extractor with two-way silica gel to help keep the tank clean and moisture-free (Fig 3).

Team TermoemCali conducts weekly tests to ensure that the biofuel is moisture-free and to determine that the quality of the biofuel is maintained to ISO standards. The team purchased a 100x microscope to aid in these tests, and maintains a logbook for test data.

Samples are routinely sent to an external laboratory for analyses that include: water and solid contents, heating value, storage stability, sulfur, product corrosion, color, viscosity, present gum, specific gravity ketone index, flash point, copper corrosion, and evaporation.

Results. By retrofitting the tank, the plant expects to double the length of time that the biofuel can be stored, thus reducing the amount of biofuel that would need to be discarded because of reduced quality or degradation over time.

To date, no free water has been detected in the biofuel stored onsite. In addition, the quality of the stored biofuel has been maintained over prolonged periods of time.

Project participants:
Ramón Uribe, maintenance planner
Diego Uribe, operations supervisor
Juan Alcaraz, maintenance supervisor

Frank A Tracy Generating Station

NV Energy Inc

1020-MW power facility located near Reno, Nev. Site has 12 generating units including a 580-MW, gas-fired, 2 × 1 combined cycle and four dual-fuel peaking units totaling 170 MW.

Regional plant director:
Wade Barcellos

ACC gearbox oil-removal piping

Challenge. The combined cycle at Tracy has an air-cooled condenser with 30 fans. Each fan has a gearbox that requires routine oil change outs (13 gallons) every 5000 operating hours as part of the preventive maintenance program. The fan assemblies are located up eight flights of stairs, 60 ft above the ground. Managing the used oil can be a hassle that requires many additional trips up and down the stairs, and carries a spill risk that could impact the environment.

Solution. Rick Davis, mechanical maintenance planner, developed a piping scheme to eliminate this issue. His installation allows personnel to pour the used oil into a funnel on the fan deck that is piped to a tote on the ground located on a containment pad (Figs 1, 2). When the tote fills, it can be quickly hauled away and replaced with a new one. This arrangement enhances safety by minimizing trips up and down stairs. It also minimizes the risk of spills. Finally, it decreases the "wrench turning" time of personnel assigned to complete this task.

1, 2. Used oil is poured into funnel above which connects to disposal tote on the ground (below)

Results. The last round of oil change outs was completed using this new installation, and the feedback from maintenance personnel was very positive.

Project participants:
Rick Davis, mechanical maintenance planner

GT hazardous-gas monitor access mod

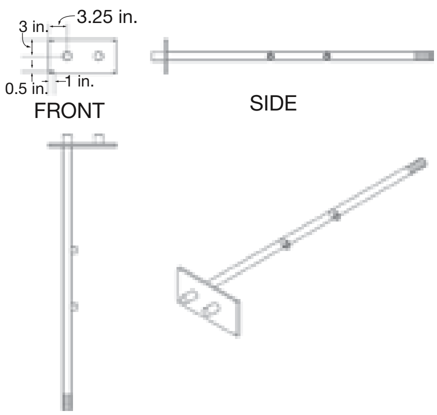
Challenge. The GE 7FA combustion turbine has two exhaust ducts located on the roof of the turbine compartment. Each duct has two hazardous-gas detectors to protect against flammable atmospheres within the compartment.

These monitors require routine maintenance and calibration to properly function. The original design limited access to the monitors through the inside of the compartment. When access is required, the turbine would have to be brought off-line and cooled so that scaffolding could be built inside the compartment. This process could add several days to a forced or planned outage, depending on the circumstances.

Solution. Kevin Steelman, ICE foreman, devised a way to remove these monitors from the outside of the duct rather than from the inside. Kevin designed a chassis to carry and support the monitor so that could be inserted and removed to gain immediate access. Plant engineering provided assembly drawings (Fig 3) and the new assembly was installed during a HGP outage at the end of 2011.

Results. This new arrangement allows immediate access to the monitors (Fig 4). If a monitor fails (which will trip the unit if the other monitor also has failed), the monitor can be replaced or calibrated in a matter of minutes, rather than days as with the previous arrangement. With a base-load facility such as Tracy, such a time savings is very impactful on our operating availability.

Project participants:
Kevin Steelman, IC&E foreman



3. Chassis supporting the hazardous-gas detector can be removed to gain immediate access to the instrument

4. Gas detector can be accessed from outside the compartment vent stack

Arrow Canyon

Arrow Canyon Complex

NV Energy Inc

Chuck Lenzie Generating Station

1100-MW gas-fired, two 2 × 1 combined cycles located near Las Vegas, Nev

Silverhawk Generating Station

520-MW gas-fired, 2 × 1 combined cycle located near Las Vegas, Nev. Co-owned with the Southern Nevada Water Authority

Harry Allen Generating Station

630-MW gas-fired, 2 × 1 combined cycle and two simple-cycle peaking units located near Las Vegas, Nev

Regional plant director: Steve Page

Multi-facility horizontal management planning

Challenge. Operating three separate plants as an integral team is difficult, even when the plants are only a few miles away from each other. Lean staff and other resources at the plants can be leveraged to optimize efficiency, when we truly operate as one team. Standardization can eliminate duplication of efforts and ensure consistent quality. Additionally, managers with different strengths can combine to form an elite team, bearing numerous qualities which can be utilized.

Solution. We developed a plan to organize the Arrow Canyon management team into areas of responsibility and ownership of initiatives on a "horizontal" (by subject) basis, rather than a "vertical" (by location) basis. Improvement initiatives are assigned and managed the same way. Execution of the plan is delineated by calendar quarter, and updated as such.

Results.

- Alignment: We achieved management alignment about how we would operate, and what areas to focus improvements on, for the selected year. This plan was used to align sub-teams and individual supervisor priorities and improvement initiatives.
- Efficiency: Eliminating duplicative efforts, plus standardization, lead to more effective execution of processes and more predictable results.
- Leveraging diverse talents: Organizing, thinking, and operating as a larger entity of three plants versus one gives us a larger talent pool, and a wider spectrum of strengths to draw upon. Higher-quality solutions come with broader perspectives
- Job satisfaction: Each individual has a broader opportunity to do what they do best, and for that to help three plants, rather than just one.
- Teamwork: True teamwork can only happen when the participants are synchronized. Using the plan as a basis allowed us to synchronize what were formerly three distinct operating entities.

Project participants:

David Hall
Forrest Hawman
Deborah Henninger
Ron McCallum
Shane Pritchard
Brian Paetzold

Chuck Lenzie Generating Station

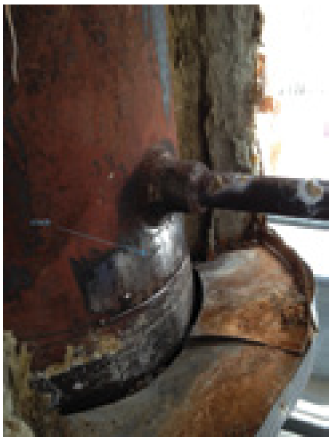
NV Energy Inc

1100-MW, gas-fired, two-unit, 2 × 1 combined cycle located near Las Vegas, Nev

Regional plant director: Steve Page

Steam-line drain valve inspection program

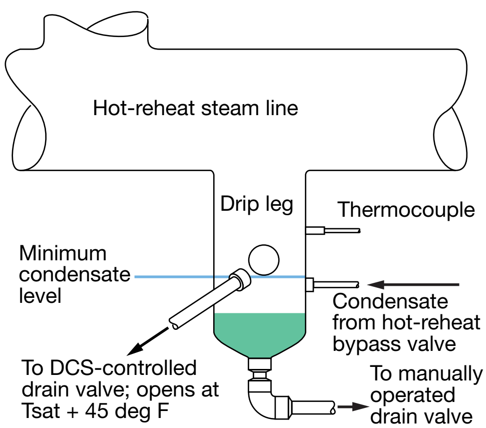
Challenge. Chuck Lenzie Generating Station had experienced repeated weld failures on the attachments to the hot-reheat drip leg. Historically the plant would identify a leak and perform NDE and a weld repair. But because of prior failures, Lenzie personnel conducted a pre-outage inspection of all drip legs and discovered yet another leak in the hot-reheat system. Insulation was removed after unit shut down and a circumferential crack was discovered in the SA335 Grade P91 base material (Fig 1).



1. Circumferential crack in P91 base material was located approximately 3 in. below the hot-reheat bypass valve drain line feeding into the drip leg

The crack was located approximately 3 in. below the hot-reheat bypass valve drain line feeding into the drip leg (Fig 2). To determine the failure mechanism, NV Energy sent the affected section of the drip leg out for metallurgical analysis. The lab's conclusion: The failure was caused by thermal fatigue initiated from the internal surface between the hot-reheat bypass valve drain line and the drip leg's end-cap girth weld.

A root-cause analysis was performed and experts attributed the failure to a leaking manual drain valve, which emptied the hot-reheat drip leg. The drip leg normally maintains a condensate level at or above the drip-leg drain line to minimize thermal transients. Condensate level is controlled by a thermocouple, which opens the DCS-controlled drain valve when temperature reaches Tsat + 45 deg F. The drain line for the hot-reheat bypass valve drains to the drip leg which normally contains a minimum condensate level. Since the drip leg was empty because of a leaking bottom drain valve, it experienced thermal transients leading to thermal fatigue and finally base-metal failure.



2. RCA revealed that thermal fatigue caused by a leaking manual drain valve was the culprit

Solution. Chuck Lenzie Generating Station implemented a comprehensive valve inspection program for all steam-line drain valves including the manual low-point drains on the drip legs. The maintenance and engineering departments evaluate valve inspection results and determine the urgency, nature, and priority of valve repairs.

Results. Plant safety and reliability were improved by performing steam-line drain-valve inspections in addition to the existing high-energy piping inspection program.

Project participants:

David Hall, plant engineering and technical services manager
Dan Schiller, lead production technician
Jimmy Daghlian, staff engineer

Washington County

Using condition-based vibration monitoring for critical equipment

Challenge. Evaluation of past equipment failures made it the main priority for plant personnel to reduce failures in critical rotating equipment.

Solution. Plant staff implemented a conditioned-based vibration monitoring program to track motors, fans, and pumps to prioritize and optimize maintenance resources to help prevent failures of process equipment. Plant technicians collect data from equipment prior to outages so that data can be analyzed and plans made about equipment problems that need to be addressed during the scheduled outage.

Washington County Power LLC
Owned by Southeast Power Gen, LLC
Operated by Consolidated Asset Management Services
305-MW, gas fired, two-unit, simple-cycle peaking facility located in Sandersville, Ga
Plant manager: Mike Spranger

Plant equipment is tested semiannually to coincide with upcoming outages. Data are analyzed and assigned different priorities depending on the severity of the problem. The priority levels are:

- Mandatory: Machine failure is certain; repair should be performed as soon as possible.
- Important: Machine problems or failure are probable within months. Repair should be accomplished at the next convenient downtime.
- Desirable: Machine problems are probable; however, repair can be deferred and scheduled based on how much faults change during future monitoring.

Results. After analyzing collected vibration data we generally identify from one to three pieces of equipment that should be maintained/repaired during the next outage. Typical corrective action includes bearing replacement, fan cleaning, or coupling replacement. We also have found equipment that needs additional monitoring. This equipment shows changes from previous baseline testing but not immediate problems, so repairs can be deferred and scheduled based on how much the faults change based on more critical monitoring.

By addressing the above issues we have increased availability and reduced maintenance problems caused by equipment failures. Rebuilding motors or addressing pump coupling issues before equipment fails improves equipment reliability and reduces maintenance costs for both equipment and resources.

Project participants:

Derek Boatright
Randy Morton
Joe Vaughn
Ralph Chandler
Tim Stevens
Robert Riddle

Walton

Walton County Power LLC

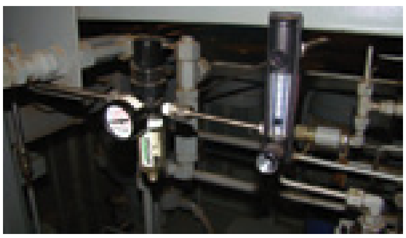
Owned by Southeast PowerGen LLC
Operated by Consolidated Asset Management Services

440-MW, gas fired, three-unit, simple-cycle peaking facility located in Monroe, Ga

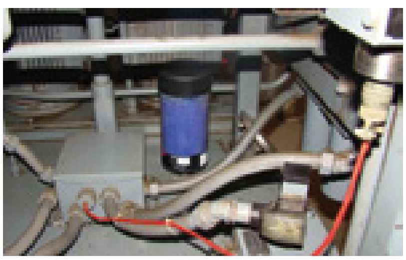
Plant manager: Mike Spranger

Reducing hydraulic-oil system varnish

Challenge. The hydraulic-oil system is used to operate the small servo-control valves in the fuel gas system. It must be maintained at approximately 100F at Walton County Power Plant and during unit idle times, heaters cycle on to maintain the temperature. This, in turn, allows the reservoir to breathe, pulling wet ambient air in. Some moisture from the air is absorbed into the hydraulic oil and causes some contamination.



1, 2. Instrument air delivered to hydraulic-oil reservoirs prevents entry of ambient air (above). Solution has been effective with desiccant canisters only requiring annual replacement today instead of quarterly (below)



Solution. The hydraulic-oil system reservoirs were equipped with a positive instrument air supply to prevent the ambient air from entering the reservoir (Fig 1).

Results. This has reduced the number of servo-valve replacements and reservoir desiccant canisters. Over a two-year period approximately half as many servo valves have been replaced. Desiccant canisters were being replaced quarterly and have been reduced to an annual replacement (Fig 2).

Project participants:
Mike Spranger
James Goins

Contractor management program advances culture of safety

Kleen Energy Systems LLC

Owned by EIF Management LLC
Operated by NAES Corp

620-MW, dual-fuel, 2 × 1 combined cycle located in Middletown, Conn

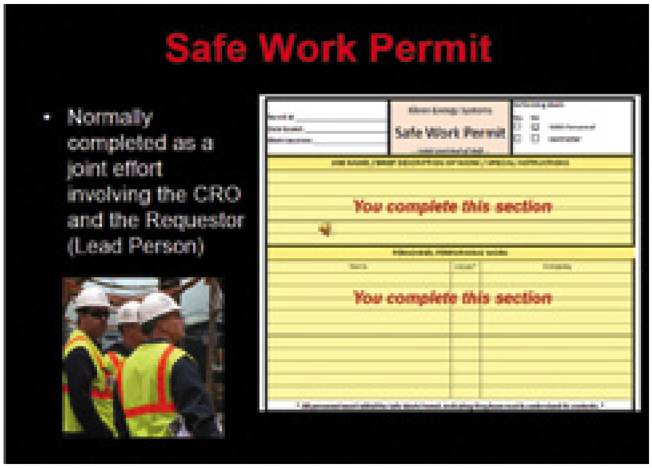
Plant manager: Drew Schneider

Challenge. Kleen Energy Systems has implemented a two-part safety improvement as part of its ongoing efforts to advance contractor understanding and compliance with the NAES corporate safety procedures.

Currently, Kleen Energy requires a Safe Work Permit for any maintenance or work done by a contractor, and the contractor is responsible for completing a "first-cut" of the Safe Work Permit, prior to it being reviewed and authorized by a Kleen Energy control-room operator. Kleen Energy strongly believes the Safe Work Permit process contributes significantly to the safety culture at the facility, and has revised and updated the process several times to maximize its effectiveness.

Solution. Kleen Energy's first safety improvement is an expanded, formal contractor training presentation, which explains in detail the Safe Work Permit. Each section of the permit is reviewed, and the sections that must be completed by the contractor are highlighted (Figs 1, 2).

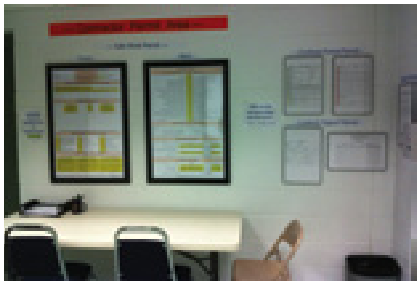
Kleen Energy's second safety improvement was to establish a "Contractor Permit Area." In this area, Kleen Energy provides an enlarged version of the front and back of the Safe Work Permit, with those portions of the permit to be completed by contractors highlighted and filled



1, 2. Every job performed at Kleen Energy must have a separate Safe Work Permit

out with sample information. Additionally, enlarged versions of other safety permits that contractors may be issued (confined space, lock-out/tag-out, and hot work) also are provided (Fig 3).

In addition to furthering contractor understanding of the Safe Work Permit process, locating the Contractor Permit Area down the hall from the control room provides contractors a separate area to complete their paperwork and enables Kleen Energy to maintain a more orderly control room—especially during outages and other times of increased contractor presence.



3. Contractor Permit Area displays safety permits that contactors may require

Results. Kleen Energy has seen a marked improvement in the quality and completeness of contractor Safe Work Permits, and see these safety improvements as significant contributors to the strong safety culture at the facility.

Project participant:
Jason Farren, EHS compliance coordinator

Juniper Energy

New process conducive to more accurate financial reports

Juniper Generation LLC
Owned by Redwood III LLC
Operated by Consolidated Asset Management Services
A 421-MW collective of nine, gas-fired, simple-cycle aeroderivative peaking facilities located throughout California.
Asset manager: Todd Witwer

Challenge. We were looking into refining estimates to more closely approximate the fuel expenses for our monthly close. We receive the actual invoice from J P Morgan around two weeks after we close the month so we have to rely on the fuel volumes provided by the plants to estimate our monthly fuel usage. But, the fuel volumes that we received from the plants did not reflect the fuel volume net of a fuel sell-back on a monthly basis for our five Bakersfield-area plants.

In June, I contacted Brad Hogue and discussed with him the on-going problem that we were having. During the discussion, I asked Brad to create a report that builds in the sell-back of fuel (with the pricing) into the monthly fuel volumes received from five plants to develop a more accurate estimate of monthly fuel expense. This would prevent a significant variance between the actual and the accrual, thus reflecting a more accurate gross margin on the report that we provide to the owner.

Solution. In July, Brad successfully created a report that accounted for the sell-backs of fuel (pricing included) into the monthly fuel volumes that we received from the five Bakersfield projects.

Results. Since we began receiving data from Brad, the wide fluctuations between estimated and actual fuel numbers have been eliminated. Today the fuel estimate for the five plants is very close to the actual invoices that we receive two weeks later. This allows us to record a much more accurate monthly fuel estimate and significantly reduce the previous month-to-month fluctuations of between 5% and 84% to almost 0% between the actual and the accrual numbers for the five plants. This provides a much more accurate gross margin for the report to the owner.

Project participants:
Huyen Do
Brad Hogue

Central Alabama

New valving protects against damage to tubing, piping

Tenaska Central Alabama Generating Station
Owned by Tenaska Alabama II Partners LP
885-MW, gas-fired, 3 × 1 combined cycle located in Billingsley, Ala
Plant manager: Robert Threlkeld

Challenge. Attemperator leaks can cause quenching of HRSG superheater and reheater tubes. This can lead to HRSG tube leaks and steam piping damage.

Solution. The attemperator water supply lines have been modified to include an automated block valve and drain valve. In addition, the drain lines have been modified to include a double bleed line. A preventive-maintenance work order to test for leaking attemperators is issued at least semiannually.

The work order includes the procedure for performing visual leak checks either during plant operation or during plant shutdowns. The results are documented on the work order and the leaking valves are repaired or replaced during the following outage.

Results. The leak checks have allowed for the timely repair of leaking block valves to prevent HRSG tube damage. The plant has been in operation for 10 years and has not experienced a HRSG tube failure as a result of operations.

Project participants:
David Wilroy, maintenance manager
Cecil Boatwright, operations manager
Robert Threlkeld, plant manager
Brian Pillittere, plant engineer
Alan Foether, lead control-room operator

AL Sandersville

AL Sandersville Power Plant

Owned by Southeast PowerGen LLC
Operated by Consolidated Asset Management Services

640-MW, gas fired, eight-unit, simple-cycle peaking facility located in Sandersville, Ga

Plant manager: Mike Spranger

Commitment to conservation reduces electric bill by $100K

Challenge. With a monthly electric bill averaging $29,700, reducing power consumption at AL Sandersville without affecting availability and reliability became a priority of plant personnel, both for its cost-saving and environmental benefits.

Solution. A review of electrical equipment to determine the most effective way to reduce power consumption without affecting availability and reliability was undertaken.

The first step was simply walking through the plant conducting an informal energy audit to help identify waste or inefficiency where power could easily be saved. Examples: Turn off lights in buildings when not in use; adjust thermostats up or down a couple of degrees. We also determined we could turn off two of the three cooling-water fan motors while the units are on cool-down control, thereby reducing the starting and stopping of the motors.

In the second phase of the project, personnel reviewed the maintenance PMs and determined that we could reduce the operating time of some equipment and save on maintenance as well. As an example, we reduced the time units are on turning gear. During months that the units were not operating, we routinely placed them on turning gear from six to eight hours; now it is four hours or less. We also complete our equipment runs while the units are on turning gear or operating, better managing service hours.

The final step was to replace equipment with more energy-efficient equipment when failures occurred. We also replaced old CRT computer monitors with newer flat-screen monitors and changed-out exit and emergency lighting with newer more efficient alternatives.

Results. Power consumption has dropped considerably with the electric bill now averaging $21,600 per month, saving almost $100,000 per year.

Project participants:

Ralph Chandler	Tim Stevens
Derek Boatright	Robby Riddle
Joe Vaughn	Randy Morton

2014 BEST PRACTICES Awards

Combined-cycle, cogeneration, and simple-cycle generating units powered by gas turbines

Deadline for entry: December 31, 2013

The editors of the COMBINED CYCLE Journal have tweaked the categories for the magazine's annual Best Practices Awards program, focusing them on industry issues to maximize the value of the solutions presented in the entries. Some general categories for years past, like design and management, have not attracted much interest of late and Senior Editor Scott Schwieger, who manages the program, and the CTOTF Leadership Committee, which provides the judges, collaborated on the changes.

At virtually all of this year's user group meetings, the concerns of owner/operators with grid requirements for fast-start assets, right-staffing and skills development, performance improvement, among others, took center stage. The entry categories listed below enable users to share ideas on these timely subjects for the benefit of all.

The bullet points that accompany each category are "grey-matter triggers" to stimulate thinking on possible subjects for your entries. They are not meant to be specific subjects for entries, although they might be in a few cases. The administrative rules for the awards program essentially remain the same, the most important being the deadline for entries: December 31, 2013.

ENTRY CATEGORIES

1. FAST STARTS

- Engine/fuel system/controls/emissions uprates/improvements/enhancements to enable fast starting of existing gas turbines in both simple- and combined-cycle service.
- Improvements/enhancements to enable other grid ancillary services—such as black start, synchronous condenser, etc.

2. NEW SKILLS/WORKFORCE DEVELOPMENT

- O&M staffing plan (permanent employees) for the next 10 years in terms of numbers, skills development required, etc, for peaking and combined-cycle facilities.
- Training program for single plant or fleet (rotating staff).
- Multi-skills training—e.g., operator/mechanic.
- Specialized training—e.g. controls, cycle chemistry, etc.
- Capturing intelligence.
- Training for simple-cycle facilities running more.
- Finding time for combined-cycle training at high capacity factors.
- Scenario training—e.g., what-if problem solving, how to respond to off-normal and emergency conditions.
- Retraining programs.
- Qualifying employees for advancement.
- Repurposing coal-plant personnel for peaker and combined-cycle duty.

3. WATER MANAGEMENT

Water-use restrictions and higher prices, plus bans in many areas on plant liquid discharges, have placed additional burdens on owner/operators. What are your best practices for such things as:

- Water-use survey and ongoing monitoring.
- Demand reduction—for example, reducing boiler blowdown, raising cycles of concentration.
- Onsite treatment of drains for reuse.
- Treatment and use of municipal and industrial wastewaters for plant makeup.
- Alternative uses for plant wastewater streams.
- Sampling and pretreatment of ground and surface waters.

4. PERFORMANCE IMPROVEMENTS

- Starting reliability.
- Availability.
- Emissions reduction.
- Thermal performance monitoring program.
- Benchmarking.
- Data retention and analysis.
- On-staff or contract service for monitoring.
- Program for identifying/correcting deficiencies; trigger points for action.
- Staff awareness/training.
- Condition-based maintenance program.

5. PLANT SAFETY PROCEDURES

Goal is to identify successful equipment/methods/procedures for assuring the safety of plant and contractor personnel, and compliance with critical standards developed by such industry organizations and professional societies as:

- NFPA (56, 70E, 85, 850, etc).
- ASME Boiler & Pressure Vessel Code.
- IEEE.

6. OUTAGE MANAGEMENT

- Planning process.
- Outage safety programs.
- Pitfalls to avoid from previous outages.

- Personnel responsibilities—plant staff, fleet specialists, contractors.
- Improving upon past performance—e.g., reducing outage cost, shortening the schedule.
- Planned-outage strategy—e.g., shut down or run 1 × 1 while working on one GT and HRSG.
- Forced-outage strategy.
- Pre-outage inspection program to fine-tune outage scope.
- Review process for OEM alerts.

7. O&M—GENERATORS, TRANSFORMERS, HIGH-VOLTAGE ELECTRICAL GEAR

Best practices for:

- Inspection.
- Maintenance.
- Repair.
- Upgrade.
- Safety.

8. O&M—MECHANICAL: MAJOR EQUIPMENT, BALANCE-OF-PLANT

BOP includes condensers, cooling towers, high-energy piping systems, major valves and pumps, water treatment, fuel handling and treatment, plant auxiliaries, etc.

- Inspection.
- Maintenance.
- Repair.
- Upgrade.

9. PREDICTIVE ANALYTICS/ M&D CENTERS

Shrinking staffs and inexperienced operators demand new solutions to "watch over" plant systems and equipment for impending problems and to maintain desired levels of availability and reliability. Two such solutions are M&D centers and software packages to warn of developing issues. What best practices can you offer in these areas, among others:

- Vulnerability analysis: How do you determine what's most likely to cause a forced outage at your plant?
- How do you decide which software packages best meet plant needs?
- How to evaluate the economic value of software packages.
- Staff capabilities/training necessary to successfully implement a software solution.
- How to evaluate in-house versus contract M&D center
- Capabilities required in an in-house M&D center, staffing, communication, decision-making regarding plant shutdown, etc.
- Alternatives to predictive analytics.

JUDGING/RECOGNITION

All entries will receive industry recognition by way of a profile in a special editorial section on Best Practices published in the Q1/2014 issue of the COMBINED CYCLE Journal. A panel of judges with asset management experience will select for formal recognition at an industry event next spring, the Best Practices they believe offer the greatest benefit to the industry given today's demanding goals of improving performance, reliability/availability, and safety, and reducing costs, while satisfying the requirements of ever more challenging regulations promulgated by EPA, NERC, OSHA, regional grids, etc.

RULES

1. Entries accepted only from employees of powerplant owners and third-party firms with direct responsibility for managing the operation and maintenance of gas-turbine-based electric generating facilities in the Western Hemisphere.
2. Maximum of four entries from the same power plant.
3. Entries must be received by midnight December 31, 2013 via regular mail/courier, fax, email, or online submission (http://www.ccj-online.com/best-practices/enter).

TO ENTER

1. Award category (select one):
   - Fast starts.
   - New skills/workforce development.
   - Water management
   - Performance improvements.
   - Plant safety procedures.
   - Outage management.
   - O&M: Generators, transformers, HV electrical.
   - O&M, mechanical: Major equipment, BOP.
   - Predictive analytics/M&D centers
2. Title of Best Practice.
3. Challenge: Description of business or technical challenge motivating the development of a Best Practice.
4. Solution: Description of the Best Practice.
5. Results: Document the benefits gained by implementing the Best Practice. For example, percent improvement in starting reliability or plant availability, dollar or percent saving in annual operating cost or reduction in annual maintenance cost, improvement in man-hours worked without a lost-time accident, etc. Please limit your response for Section 5 to the equivalent of three pages of single-spaced 12-pt. type. Add photos, drawings, tables, etc.,
6. Na me of plant.
7. Plant owner.
8. Plant personnel (and their titles and company affiliation) to be recognized for developing and implementing the Best Practice.
9. Contact for more information (name, title, company, phone, fax, e-mail).

Refer questions/submit entries to:

Scott Schwieger, senior editor, COMBINED CYCLE Journal, 7628 Belmondo Lane, Las Vegas, NV 89128.

Voice: 702-612-9406. Fax: 702-869-6867. E-mail: scott@ccj-online.com

Inspect steam valves for stellite delamination

By Kim Bezzant, Structural Integrity Associates Inc

Stellite liberation from large valves installed in high-pressure (HP) and hot reheat (HRH) steam systems serving F-class combined cycles has emerged as an important industry concern. Tight shutoff of parallel-slide gate and non-return globe valves has been compromised in some cases, based on feedback from plant personnel; steam-turbine components also have been damaged.

EPRI has established a committee on "Cracking and Disbonding of Hardfacing Alloys in Combined-Cycle Plant Valves" to dig into the details. The work, funded by several sponsors, began early this year. John Shingledecker (jshingledecker@epri.com), the technical manager for this program, said the project timeline is estimated at 14 months. The first formal review of industry experience is incorporated into the program for the upcoming EPRI Fossil Materials and Repair Program Technology Transfer Week, June 24-28, in Destin, Fla.

Owner/operators, valve manufacturers and service organizations, and other interested parties expect one outcome of the R&D effort will be a more reliable process for the bonding of stellite to discs, seats, and slides for valves subjected to steam temperatures approaching 1100F, as well as to rapid quenching caused by improperly operating desuperheaters and/or drain systems. The solution also may require changes to current industry inspection, operating, and maintenance procedures.

Industry experience suggests inspection of large steam valves at plants built during the late 1990s and early 2000s at the next hot-gas-path (HGP) or major inspection if this has not been done previously (see sidebar that follows this article). A visual inspection will confirm stellite liberation, dye penetrant testing will reveal cracking not visible with the naked eye, and a *straight-beam* ultrasonic examination will identify disbonding.

But before opening your valves, be sure to have a game plan for repair or replacement in case you find damage. Failure to plan ahead could significantly add to your outage schedule. Here are your options if damage is found:

- Replace the existing valve with a new one.
- Cut the valve out of the line and send it to the manufacturer or a *qualified* third-party shop for repair.
- Repair the valve inline.

Owner/operators who have already faced repair/replace decisions suggest that you factor the following facts into your decision:

1. Cracking in evidence is typical of that found in stellite seats for combined stop and control valves on steam turbines

- The lead time for new valves may extend beyond a year.
- Shops capable of doing quality valve work and welding generally have a backlog.
- Quality repairs are difficult to make inline because of preheat and access requirements.
- Field-service organizations with the requisite in-situ valve repair experience are extremely busy.
- There is no industry standard for applying hardfacing. Manufacturers and repair firms have their own procedures and they should be qualified metallurgically before work begins on your valves. Plus, owner/operators are advised to carefully monitor repair work to the qualified written procedure.

Case history

The D11 steam turbine for a 2 × 1 7FA-powered combined cycle recently experienced an increase in HP-cylinder inlet pressure as well as a slight decrease in electrical output. Design steam conditions for the HRSGs were 1450 psig/1070F at the HP outlets and 450 psig/1067F at the HRH outlets. Lifetime operating hours totaled about 45,000, starts (mostly warm) 150.

Plant personnel began their investigation by following the recommendations of the OEM's Technical Information Letter (TIL) 1629-R1, "Combined Stop and Control Valve Seat Stellite Liberation," released Dec 31, 2010. The inspection team found that no stellite had been liberated from the valve seat; however, multiple cracks were found in the stellite inlay (Fig 1).

Important to note is that the two stellite alloys typically used for hardfacing of valve seats and discs are Stellite 6 and Stellite 21, trademarked products of Deloro Stellite Group. Since investigators did not know whether Deloro cobalt-based hardfacing alloys were used in the fabrication of these valves, the generic names Alloy 6 and Alloy 21 are used here.

This was not the first inspection of the combined stop and control valve (CSCV). It had been inspected during the 2009 major, shortly after the TIL was first published on Jan 30, 2009. The original TIL 1629 only called for visual (VT) and liquid-penetrant (PT) inspections. No cracking was found at that time. As noted above, Rev 1 of the TIL requires ultrasonic inspection, to identify any lack of bonding between the inlay and the base metal, if the unit has less than 50 starts.

Significance of the 50 starts: After that number of cycles, metallurgists believed any disbonding would have propagated to the edge of the inlay and could be identified with VT or PT. While

the steamer had more than 50 starts at the time of the 2009 inspection, no PT indications were found at the edge of the hardfacing inlay. However, the ultrasonic inspection in 2012 revealed significant disbonding of the inlay.

A borescope inspection of the HP turbine revealed significant damage to diaphragms and rotating blades in several stages. During CSCV disassembly, metallic debris was found in the valve's strainer (Fig 2). Analysis verified that its composition was consistent with the hardfacing alloy used on valve seats. Some debris had cut through the strainer and damaged HP turbine components.

The next step was to identify the source of the hardfacing debris. A key clue: Operations personnel had reported that the HP stop valves were not sealing during shutdown. They were disassembled and the Unit 2 HP line stop was found with stellite missing from both the upstream and downstream seats (Fig 3). The Unit 1 HP line stop had its stellite in place, but showed signs of significant disbonding.

Based on these findings, plant management decided to check other high-temperature valves for damage. The inspection list included these eight valves on each unit:

- Three HP gates.
- One HP non-return globe.
- One CSCV.
- One HRH gate.
- One IP gate.

2. Hardfacing debris was removed from the strainer for a combined stop and control valve

- One cold reheat (CRH) check.

Inspection results: Disbonding of hardfacing was identified on all HP and HRH valve seats; also on the seats and guide rails of the HP non-return globe valves. The IP and CRH valves showed no disbonding. Further investigation revealed that the hardfacing for the HP and HRH valves was applied using the Plasma Transferred Arc Welding (PTAW) process and for the HP non-return globes it was the Shielded Metal Arc Welding (SMAW) process.

Also, hardfacing on the HP and HRH gate-valve seats and discs was of bi-layered construction: An Alloy 21 buffer layer applied to the Grade 91 seat rings and an Alloy 6 finishing layer. The former is a low-carbon CoCrMo alloy with the AWS/ASME solid-wire

3. Delamination of the upstream seat ring (left) and downstream seat ring (right) for an HP stop valve is in progress filler-metal designation ERCoCr-E. It is characterized by reasonable ductility and metal-to-metal wear resistance at elevated temperatures. By contrast, Alloy 6 is a high-carbon CoCrW alloy with an AWS/ASME solid-wire designation of ERCoCr-A having improved metal-to-metal wear resistance at elevated temperatures.

The valve manufacturer's service technician said that prior to the millennium, Alloy 6 typically was used for hardfacing of valve seats. But multiple disbonding incidents prompted his company to adopt the bi-layered approach. The thinking was that the improved ductility of Alloy 21 would minimize the risk of disbonding while the finishing layer of Alloy 6 would maintain a high degree of metal-to-metal wear resistance. Research revealed other valve manufacturers had similar issues with disbonding and they are using Alloy 21, stainless steel, or Inconel as buffer layers.

Evaluation of the fracture surface raised concern that the failures were located in the Grade 91 base metal and might be similar to other creep-related dissimilar-metal failures found in Grade 91 piping (Fig 4). However, examination of the Grade 91 base metal revealed a tempered martensitic structure consistent with material that had been properly heat treated.

The heat-affected zone (HAZ) created by the deposition of hardfacing, while of a normal structure for Grade 91 material, was wider than normally would be expected given the thickness of the overlay. This indicated that relatively high heat inputs were used during the PTAW application of at least the buffer layer of Alloy 21. There was no evidence of creep damage in the Grade 91 HAZ.

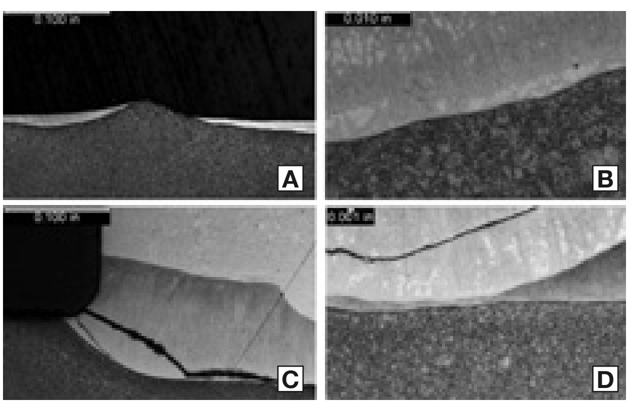
Cracking that contributed to the disbonding of the hardfacing from the base metal developed near the interface between the valve seat and the stellite. It was caused largely by brittle fracture that had propagated through the Alloy 21 buffer layer. In some areas, the cracking propagated very close to, or along, the dissimilar-metal interface between the Grade 91 and Alloy 21.

However, in these areas the fracture location appeared to be the result of the orientation of the brittle fracture rather than any unique "weakness" associated with the interface (weld fusion). Metallurgical evidence suggested that the dissimilar metal interface was not uniquely susceptible to the cracking and was only directly involved in the accumulation of damage (Fig 5).

4. Valve-seat fracture surface typically looks like this

Energy-dispersive X-ray spectroscopy (EDS) was performed on several samples to determine the chemical composition of the hardfacing layers. This analytical is used for elemental analysis of a material sample. The results showed high levels of iron dilution in the Alloy 21 buffer layer—ranging from 38% to nearly 70%.

Micro-hardness traverses also were taken to identify the hardness profiles of the



5. Weld fusion line between Grade 91 and Alloy 21 is shown at different magnifications: Fig A reveals remnant Alloy 21, B is a close up of the weld fusion line, C shows primary and secondary cracks in the Alloy 21 buffer layer, D reveals a primary crack and sound weld fusion line

materials involved. Grade 91 and Alloy 6 had hardness values within their expected ranges. But the Alloy 21 buffer-layer hardness, which ranged from 39 to 70 Rockwell C (most readings were above 50), was well outside the range expected for this material. Deloro Stellite says the hardness of its Stellite 21 typically is 27 HRC and can work-harden up to 40 HRC.

Cobalt-based hardfacing alloys usually are considered for high-temperature applications because of their wear- and oxidation-resistant properties at elevated temperatures. These alloys rely on carbides for wear resistance and typically contain 24% to 32% chromium for oxidation resistance, plus 3% to 14% tungsten or molybdenum for added strength and for their carbide-forming ability.

Low-carbon hardfacing alloys, such as Alloy 21, which has 0.15% to 0.45% carbon, are reasonably ductile and provide metal-to-metal sliding wear resistance and cavitation erosion resistance. High-carbon alloys, like Alloy 6 (0.9% to 1.4% carbon), have limited ductility, but offer increased abrasion resistance.

It would appear that the use of Alloy 21 as a buffer layer was an attempt to interpose between the Grade 91 base metal and the Alloy 6 wear layer a layer of more ductile material to better tolerate dynamic loads. However, the properties of the Alloy 21 buffer layer were altered significantly by changes in the weld-metal chemistry resulting from excessive dilution of the hardfacing during welding.

Fig 6 shows the correlation between hardness values and the level of iron dilution for the Alloy 21 buffer layer. While iron was used as the basis for calculating the percent dilution in this case, other key elements would have changed similarly. Note that as the level of dilution increases, the maximum hardness of the hardfacing deposit also increases. Thus the high rate of iron dilution into the Alloy 21 buffer layer of this valve seat produced a very hard layer with substantially reduced ductility.

As indicated above, investigators assumed that the intent of the Alloy 21 buffer layer was to provide a ductile layer under the final Alloy 6 layer. This is consistent with one of the recommendations from Stoody, a respected provider of hardfacing alloys (access "50 Hardfacing Tips" at http://victortechnologies.com/stoody): "Never put a tough ductile weld deposit on top of a harder, more brittle hardfacing deposit. Such deposits will spall, and lift off the part. The hardfacing alloy always should be applied on top of the more ductile material."

Although it appears that the valve

manufacturer attempted to do this by applying an Alloy 21 buffer layer, the level of iron dilution into the buffer layer apparently created the situation Stoody warned against—a softer deposit on top of a harder deposit, which resulted in disbonding of the hardfacing overlays.

To identify a possible driving force for crack growth, steady-state and transient heat-transfer and thermal stress analyses were performed using the finite-element method. The analyses included a postulated thermal shock (rapid cool-down) and a typical startup and shutdown thermal transient based on operational data provided by the owner/operator. Both the heat-up and thermal-shock stress analyses identified significant tensile axial stress at the Alloy 21/Grade 91 interface. This tensile stress is a possible driving force for crack growth.

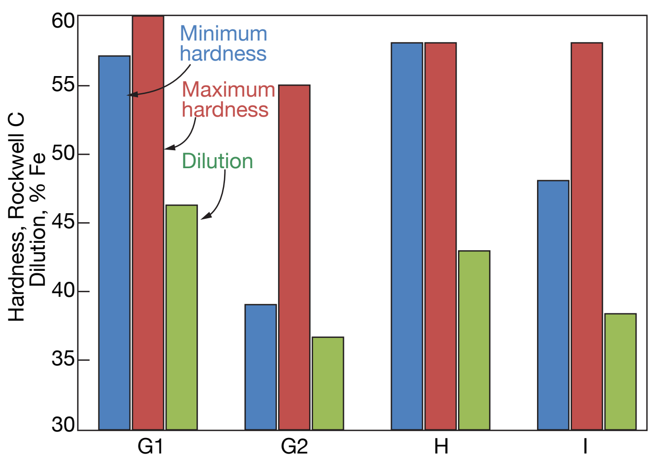
The type of failure associated with the HRSG valve seats described here typically has not been observed in conventional fossil-fired steam-plant valves. For this case, it appears that the disbonding of hardfacing is caused by several conditions, including the following:

- Higher operating temperatures than are normally experienced in conventional fossil-fired units, specifically 1050F to 1080F, versus 1005F.
- Higher rates of cycling, plus operating conditions capable of producing large quantities of condensate that contribute to thermal shock.
- Material combinations not typically found in fossil-fired steam plants—such as Alloy 21 and Alloy 6 deposited on Grade 91.
- Hardfacing layers with high hardness caused by excessive base-metal dilution into the hardfacing overlay.

Although the foregoing case history specifically deals with the valves from one manufacturer using composite Alloy 21/Alloy 6 hardfacing overlay, similar valve-seat failures have occurred in valves of various manufacturers not using buffer layers. Reports from several combined-cycle owner/operators leads investigators to believe the debonding described may be a generic issue.

Finally, if your inspection identifies disbonding, would you continue to operate or shut down to repair/replace the valve? This is not an easy decision to make for at least two reasons: First, the cause of disbonding is not yet fully established and, second, there is no data to predict the propagation rate of disbonding.

If repairs are needed, or if you're buying a new valve, it would be pru-



6. Correlation of buffer-layer hardness and iron dilution shows that hardness increases with increasing iron transport from the base metal to the hardfacing material dent to specify a limit on base-metal dilution into the first layer of hardfacing of between 10% and 20%, based on what investigators have learned to date. Minimizing base-metal dilution should reduce the hardness levels in the first layer of hardfacing and reduce the potential for disbonding. Qualify a prospective valve supplier or repair services provider by specifying a demonstration to prove their welding process can minimize dilution.

Whether you have experienced disbonding or not, be proactive regarding the review and modification of operating procedures to reduce the amount of condensate produced in superheater and reheater tube bundles during start-

Valves didn't get the respect they deserved

The editors first learned of stellite delamination in a large valve designed for high-pressure (HP)/high-temperature steam service at the 2009 7F Users Group conference. But all the attention that incident received was a brief mention late in a long user presentation profiling the major inspection of a combined-cycle plant. More than 200 owner/operators were in attendance, yet no questions were asked about the issue—at least none the editors can recall—and it was quickly dismissed. Fig 1 shows stellite liberated from the seat of a 20-in. hot-reheat block valve installed at that presenter's plant and collected in the strainer for the steam turbine's combined stop and control valve.

Another alert concerning stellite liberation came from GE Energy, which issued Technical Information Letter 1626 on Jan 30, 2009. It advised steam-turbine owners to check the condition of the stellite inlay sections used in fabricating seats for the OEM's combined stop and control valves. Revision 1 of that TIL, dated Dec 31, 2010, recommended a "one-time seat stellite inlay UT inspection during valve installation or next planned maintenance inspection."

Yet another alert regarding stellite cracking was sounded by Ed Sundheim, director of engineering for the North American Energy Alliance LLC, Princeton, NJ, who had intended presenting on the subject at the spring 2011 conference of the Combustion Turbine Operations Technical Forum™, but the lunch bell sounded before he got to the podium.

Instead, Sundheim provided the editors his notes to develop the CCJ article, "Don't forget to inspect your valves," a case history charting the inline repair of F91 parallel-slide gate valves at Newington Energy LLC. It was published in the 2011 Outage Handbook; access via www.ccj-online.com using the search function.

More recently, the Dogwood Energy Facility was recognized with a Best Practices Award at the spring 2013 conference of the CTOTF™ for its efforts in the identification and repair of a cracked seat on the 12-in. HP stop/check valve for one of its

A. Stellite liberated from a large block valve was captured by the strainer protecting the steam turbine. The origin of the file remains a mystery

HRSGs. Except here, the seat material was Type-316 stainless steel; no stellite was involved. Get the details on p 54.

The industry recently learned of many more incidents of stellite liberation. CFM/VR-TESCO LLC (formerly Continental Field Machining), a leading valve services company, reported earlier this year at a meeting of the Valve Manufacturers Assn (VMA) that in 2011 and 2012 it had repaired 50 valves manufactured from F91 (forged body) or C12A (cast body) and ranging in size from 12 to 24 in. More than half of these jobs involved stellite liberation.

The repair projects profiled were split roughly 50/50 between valves within the Code boundary and those that were part of the boiler external piping. Repairs on the former were performed according to guidelines presented in Section I of the ASME Boiler & Pressure Vessel Code and in the National Board Inspection Code as well as jurisdictional requirements. Valves outside the Code boundary were performed according to ASME B31.1.

Background

The editors spoke with owner/operators, a valve manufacturer, and a service firm, as well as with Kim Bezzant of Structural Integrity Associates Inc, regarding issues associated with high-temperature steam valves. It seems that many problems the industry is experiencing today can be traced to a general lack of respect for valves and inattention to detail regarding their manufacture, installation, operation, inspection, and maintenance.

Success in all aspects of equipment and system design and manufacture/construction hinges on good specifications and involvement by the owner, or its representative, in the work contracted to others. Price always is important until breakdowns force a plant out of service. Then the quality that should have been built into the equipment suddenly becomes important. As the Dutch are fond of saying, "Too soon we grow old, to late smart."

Speaking with owner/operators you get the feeling that valves were considered pedestrian equipment. No owner the editors spoke with went to the fab shop to inspect the product during manufacture or to verify inspection results. One said valves were part of the EPC contractor's scope of supply and only their employees were allowed in the shop, by contract. Did the EPC send someone to the shop? Certainly unlikely in one case examined where the welding was so poor even an inexperienced inspector likely would have rejected the job.

Someone else told the editors he thought his plant's valves had forged bodies, but they actually were less-expensive castings. At least some of those castings were made in far-off places where QC didn't exist 10 years ago, which is why the industry still hears about defects in valve bodies. You might also consider checking the bodies of your high-temperature valves when inspecting for stellite cracking and disbonding. Recall how surprised many users were when they found out that their P91 didn't meet hardness specs, the wrong weld filler up and shutdown. Verify, too, proper operation of attemperators to be sure excess water is not entering the steam path. Check your drain system to assure any condensate formed is being removed quickly and completely. CCJ

material was used, P91 was welded to P22 in error, etc.

One owner's experience

Discussions with a boiler engineer for an owner of multiple combined-cycle plants equipped with HRSGs and valves from several different suppliers revealed how pervasive the stellite cracking and disbonding issue is. His company implemented a fleet-wide survey of its large steam valves and now tracks on an ongoing basis the inspections, detailed findings, and repairs for each critical valve.

This owner's best practice today regarding inspection is to open and inspect valves on a two-year cycle, and have a capital spare. All components are checked—including springs, stems, discs, and seat rings. Straight-beam ultrasonic examination is used to locate any disbonding between the hardfacing material and the valve body. This is important: Where there is disbonding, cracking usually follows.

Don't chintz on inspections, the boiler engineer advised. A proper job requires top talent. The company you select should be experienced in this work, have the proper coupons for calibrating its instrumentation, and provide a savvy technician to conduct the inspection.

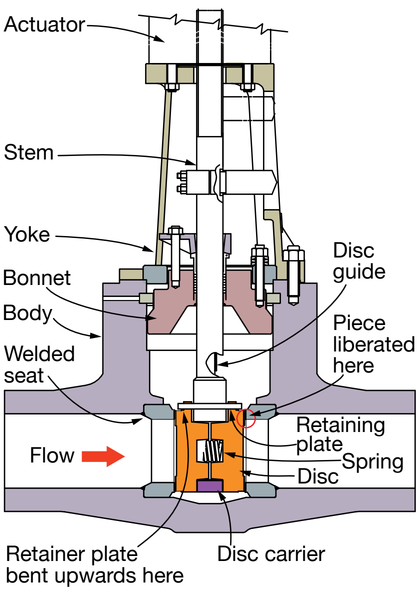
Corrective action by this owner, when necessary, is guided by inspection findings and may differ from plant to plant depending on the damage encountered, because there are no industry standards for hardfacing and some other required repairs. The utility expects the EPRI task force discussed in the main text to provide a much-needed guideline for applying hardfacing alloys in a manner that minimizes, and possibly eliminates, the damage being experienced today. Its expectation of a viable EPRI solution was echoed by virtually all industry participants interviewed—including other owners, operators, manufacturers, and repair firms.

At the first of this owner's F-class combined cycles to inspect its HP steam valves, engineers found cracks in the integral seat for a stop/check valve that propagated through the stellite and into the valve body. A field repair crew machined off the hardfacing, chased the cracks to the bottom and repaired the body with Grade 91, and then refaced the seat with stellite.

Operability issues experienced with a parallel-slide gate in HP steam service at another plant in the fleet raised a red flag and engineers inspected all four HP valves on its two HRSGs during an outage planned for 10 days. That outage was extended by about a month and half because of the valve work.

Cracking of seats and discs was found on both parallel-slide gate valves (Fig B) and both stop/checks (Fig C). Some of the liberated stellite still has not been found. All four valves were removed and send to a qualified shop for repairs.

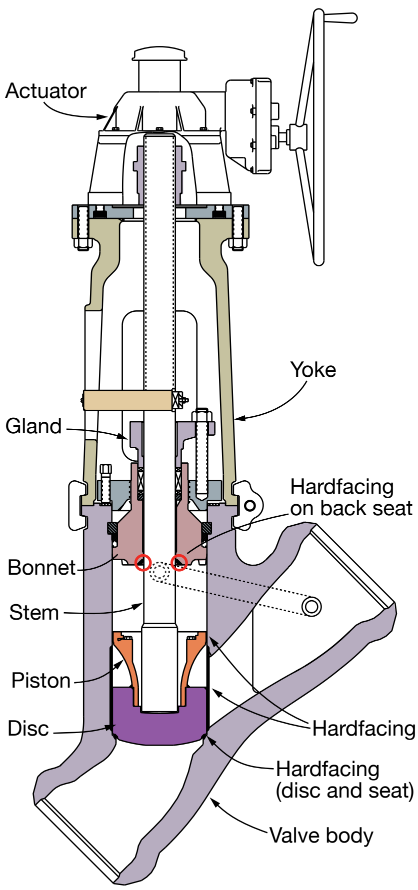
The parallel-slide gates had serious issues. The retainer plates in both either broke or bent and contributed to body damage; pieces of stellite liberated from the seat rings on both gates. In addition, the disc came off the stem on one of the valves and resultant chattering caused still more damage. These valves were completely overhauled and repaired; Grade 91 material was built up where necessary and Stellite 21 hardfacing was applied in wear areas. In effect,



B. Parallel-slide gate valve with forged body and electric actuator was rendered inoperable by damage. The retainer plate bent upwards, a piece of the seat was liberated, and the disc broke free from the stem (above)

C. Stellite liberated from the stop/check valve but was not replaced after repairs (right)

the valves were restored to their original condition.



For the stop/checks, hardfacing was machined off and the Grade 91 material dressed; stellite was not reapplied. Given the company's experience and the state-of-the-art in hardfacing, Grade 91 seating surfaces were viewed as the least-risk alternative.

Another F-class 2 × 1 combined cycle in the fleet recently inspected its HP valves. Seats for the gate valves are integral with the bodies and dye penetrant identified cracks in both, but there was no evidence of disbonding. Cracking of the stop/check seats also was in evidence, with no disbonding. However, the guide ribs were galled. Stellite was removed and the guides are now Grade 91 with no hardfacing.

Lessons learned. Before the owner inspects for the first time valves on another of its combined cycles approaching 10 years of service it will take delivery on two new HP gates and stop/checks. Experience indicates that the chances of finding valves as-new is unlikely and alternative with least schedule impact is to cut out the existing valves and drop in new ones.

In sum, the owner's near-term strategy has been to minimize operational risk by verifying the integrity of the fleet's HP valves first. These valves, it believes, have the most severe service conditions. Long-term thinking is that EPRI will have established best practices for steam valves before inspection of hot-reheat and other valves is necessary.

The manufacturer's view

Dr Nabil T Tarfa, who recently joined Velan as VP materials and process technologies, shared his thoughts on cracking and disbonding of hardfacing in combined-cycle service. Montreal-based Velan is one of the electric-power industry's leading suppliers of valves for high-pressure/high-temperature steam service. Most of company's valves have forged bodies, Tarfa said, because forgings have a more uniform structure than castings and generally are of a higher quality.

Asked why he believes steam valves for F-class combined-cycles are experiencing so many problems of late, Tarfa summed up his thoughts succinctly: There's a gap between the service conditions specified by the buyer and how the equipment is being operated. He said Velan is investing considerable time and effort to determine both the root causes of the problems experienced and how to address them.

The company is a participant in the EPRI research program on cracking and disbonding of hardfacing alloys and also is sponsoring a research project with a Canadian university to identify factors contributing to the failures and how to address them. He believes that an effective solution hinges upon an open exchange with users, to learn more about how plants are operated in the competitive generation industry.

Tarfa said there are several important factors to consider in analyzing the cracking/disbonding problem, including these:

- The metallurgical nature of the bond between the hardfacing material and base metal.
- Temperatures involved, and the times at those temperatures. Plus, numbers of cycles, ramp characteristics, thermal shock caused by quenching of hot metal by condensate, etc.

Pentair, which provides a wide range of valves to power producers under several brands—including Crosby, Sempell, Dewarance, and Clarkson—offered a brief overview of hardfacing issues at recent meeting. The speaker acknowledged that "stellite failures are an industry issue," and stated the following:

- Each OEM must have a written procedure, which must consider (1) the shape, dimension, and accessibility of parts to be welded, (2) range of dilution to achieve a specified hardness, (3) where the job will be performed—in the field or in the shop, (4) welding position, and (5) level of automation.
- The application is a consideration that must be reviewed.
- The application of weld overlay is critical.
- The right material for the right application.

Finally, "For determination of hardfacing procedures and application of weld material, shape of components, used materials, and operating conditions must be considered. A general rule to have a unique standard for deposition of of hardfacings is not feasible. Each manufacturer has to select and qualify individual processes for hardfacing."

Field repairs

CFM/VR-TESCO LLC (it stands for Continental Field Machining/Valve Repair-Technical Service Co LLC) does the lion's share of its business in powerplants—about 90%, in fact. Several people the editors spoke with believe it to be the "go to" firm for in-situ valve repairs. An overview of what

CFM presented before the VMA meeting mentioned earlier offers combined-cycle owner/operators valuable perspective on the extent of the industry's valve challenges.

Most of the ASME Section I repairs the company has completed can be segregated into these three groups:

- Valves requiring seat replacement.
- Removal and rewelding of integral seats.
- Repair of cracks in the valve body, guide ribs, and/or disc guides.

Half of CFM's "R" stamp repairs were on valves with SA217-C12A bodies that required replacement of seat rings. The partial-penetration welds holding the seat rings to their respective valve bodies were cracked—the majority all the way around, allowing the ring to fall out of the seat pocket. Portions of the hardfacing was missing from some of the seats. All of the valves with Type-316 stainless steel seats were cracked 360 deg and were replaced with seats of A182-F91or A387 Grade 91 Class II materials.

The remainder of the repairs were on integral valve seats. Most (85%) of those valve bodies also were made from SA217-C12A material. All valves had cracks in the seat-area hardfacing going back into the base material. The majority also had cracking in the guide ribs. In some cases, the stellite had become disbonded from the base material and had moved downstream. This required removal of the remaining stellite and undercutting of the base material. After the base metal was built up, hardfacing was applied.

The majority of the valves repaired under B31.1 (those outside the ASME Code boundary) were parallel-slide gate valves with bodies of A217-C12A. Seat rings were of F91 and P22 materials. Defects were the same as those found on the Section I valves: (1) Seats cracking in the heat-affected zone on the body side of the body-to-seat-ring weld. (2) Stellite breaking off the seat-ring face and entering the steam system.

Welding procedures. Users might consider investing time to learn about stellite and welding procedures for hardfacing. If you have responsibilities on the steam side of the plant, you're likely to be involved in valve repairs at some point. The Deloro Stellite website offers a good backgrounder on hardfacing materials and such pertinent welding processes as manual metal arc, tungsten inert gas, metal inert gas/metal inactive gas, and plasma transferred arc.

Casey succeeds Kimble as president of world's largest aero user group supporting power generators

Jon Kimble told the large assembly of attendees participating in the opening session of the WTUI's 23rd Annual Conference and Exhibition at the San Diego Convention Center on March 11 that he was stepping down as president of the Western Turbine Users Inc after five years at the helm because of demanding business and personal commitments. The announcement came as a surprise to virtually all in the room except the officers and directors.


Kimble


Casey


Merritt


Boyd

Chuck Casey, general manager for Riverside Public Utilities and the organization's secretary, was elected to succeed Kimble. Other organizational changes: David Merritt, a board member and deputy general manager of power operations for Kings River Conservation District, was elected a vice president, while Alvin Boyd, O&M manager for Kings River, was elevated from his director position to secretary.

In addition, Board Member Brad Hans, plant supervisor at Lincoln Electric System's Terry Bundy Generating Station, completed his three-year term, leaving three vacancies on the board of directors. The following were elected by the membership to fill those positions: Bryan Atkisson, a plant manager for Riverside Public Utilities; Charles Byrom, Anaheim Public Service; and Daniel Arellano of Calpine Outage Services.

Treasurer Wayne Kawamoto was next to the podium to review WTUI's financial statement, which was accepted unanimously by the membership. The plant manager for Corona Energy Partners Ltd announced that attendance was expected to surpass the 1000 mark, which would make the 2013 conference the second largest in the organization's history. Kawamoto added that the 2014 meeting will be held March 23-26 at the Renaissance Hotel/Palm Springs Convention Center. Venue for the 2015 meeting is Long Beach; no other details were available.

The Western Turbine conference is dominated by breakout sessions focusing on O&M issues associated with the LM2500, LM5000, LM6000, and LMS100. There also are multiple tracks featuring presentations in special interest areas. Social events and meals round out the program. This article covers topics from the San Diego meeting of general interest to the LM (land and marine) community, and in some cases, owner/operators of other types of engines as well. Technical details are reserved for a special report in 3Q/2013 covering the specifics of the four gas turbines.

Depot presentations

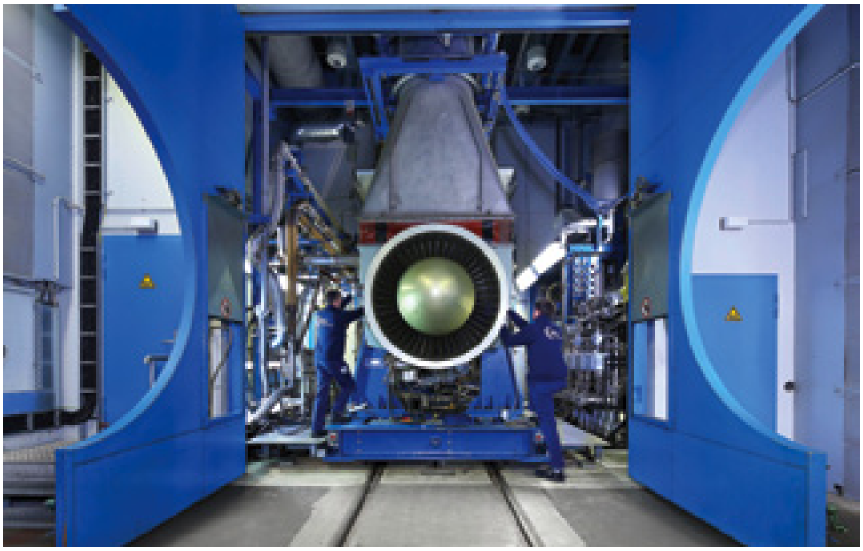
The success of the Western Turbine meeting is underpinned by the technical and financial support of the OEM and the five depots licensed by the GE to inspect and repair the four engines addressed by the group: TransCanada Turbines (TCT), Calgary; MTU Maintenance Berlin-Brandenburg GmbH, Ludwigsfelde, Germany; Air New Zealand Gas Turbines (ANZGT), Auckland; Avio SpA, Rivalta de Torno, Italy, and IHI Corp, Tokyo.

Representatives of the depots work closely with the WTUI leadership to prepare "lessons" for each of the breakout sessions. Deliverables include notebooks, given to participants, which review recent service bulletins and service letters issued by the OEM; summarize depot findings since the last meeting; explain causes of performance loss and how to correct them; and provide the fundamentals of critical-parts life management.

The knowledge contained in the notebooks, and that shared by LM experts during the meeting, provide comprehensive, low-cost training for all those involved in the operation, inspection, and maintenance of aero engines. Electric power generators obviously agree with the value proposition offered by Western Turbine because each year first-timers comprise between one-third and one-half of the user attendees.

Each depot provided a thumbnail sketch of recent activities during the opening session of the meeting. Here are key take-aways:

ANZGT. General Manager John Callesen of Air New Zealand Gas Turbines, first to present, introduced his team; Bob Cox, business development manager, reminded the group that ANZGT had partnered with Consolidated Asset Management Services (CAMS), Bakersfield, Calif, in 2011 to better serve the heavy concentration of LM users in the US—with specific



1. MTU recently remodeled its test cell in Ludwigsfelde to accommodate the testing of a broader spectrum of industrial gas turbines, such as the LM6000PF and the LM2500+G4

focus on LM5000 owner/operators. GM of the US operation is Frank Oldread. Both he and his Bakersfield colleague, Jimmie Wooten, are well known to WTUI members, both having served the group as directors.

Avio, IHI. Avio's capabilities as a Level 4 independent services provider for LM2500 engines were described by Commercial Manager Luca Agliati. Next, IHI's Kojiro Umene, GM for customer support, and Eiji Okuyama, VP business development, revealed the company's new corporate message ("Realize your dreams"), reviewed the history of the 160-year-old firm, and discussed the capabilities of its new Level 2 shop in Cheyenne—a partnership with Reed Services Inc. The Wyoming organization also offers Level 1 and 2 onsite maintenance and troubleshooting services, and it has an LM6000PC lease engine and rotable modules. Ken Ueda, who was station engineer for IHI's West Coast operation, is now the Cheyenne service manager.

In Japan, IHI has a Level 4 GE-authorized shop for the LM2500 and LM6000. Parts repairs are done in-house. LM6000PC and LM6000PD lease engines are available. The company also has a dedicated test cell for LM engines.

MTU Maintenance Berlin-Brandenburg's Level 4 Ludwigsfelde shop is the company's center of excellence for the repair of industrial gas turbines. It is an authorized service provider for all models of GE LM2500, LM5000, and LM6000 engines. This lead facility closely cooperates with MTU's support shops in Hannover, Munich, Kuala Lumpur (Malaysia), New Braunfels (Tex), Ayutthaya (Thailand), Sao Paulo (Brazil), and Norway.

The company recently remodeled its test cell in Ludwigsfelde to accommodate the testing of a broader spectrum of industrial gas turbines, such as the LM6000PF and the LM2500+G4. Among the improvements are an enhanced monitoring database and data acquisition system, a six-valve fuel skid, and Mark VIe control system. Four LM engines had already been tested in the new facility by the time of the meeting: LM2500+(DLE), LM2500 (SAC), LM 6000PC, and LM6000PF (Fig 1).

A milestone was recorded in September 2012 when MTU overhauled its 1000th industrial gas turbine, nearly 900 of those LM engines. The MTU speakers encouraged attendees to visit its plant near Berlin and offered an entertaining video on music, dance, art, and fashion to show how a serious business trip could be extended into a good time.

TransCanada Turbine's Dale Goehring discussed the company's shop capabilities and excellent safety record: No lost-time accident in the last three years (more than 1.5-million man-hours). Most of the presentation focused on TCT's facilities—including its new Level 4 Airdrie plant about 20 minutes north of Calgary, which handles the LM6000, LM2500+, and LM2500. The joint-venture company (TransCanada Corp and Wood Group GTS) also has Level 2 "hospital shops" for small jobs in Houston, Bakersfield, Syracuse, Cumbernauld (UK), Singapore, and Perth (Australia).

Mention was made of the TCT's 15th anniversary in June 2013 and its experienced people resources available worldwide. Goehring also discussed TCT's LM6000 test facility, which opened last December. It enables the company to provide incoming engine testing, troubleshooting, and diagnostic services for LM6000 PA, PB, PC, PD, and PF engines. Test-cell design features—including quick-release mechanisms for essential engine services and load banks—will enhance TCT's ability to respond quickly to customer requirements.

Highlights of the OEM's presentation were the following:

- There are now more than 2200 LM engines worldwide.
- Safety is a top priority; every employee is empowered to stop a job for a safety violation.
- The first overhauls, on LM6000s, have gone through GE's Level 4 facility in Brazil.
- A new Level 2 shop was recently completed in Australia.
- A new leadership team is in place at the Houston Service Center. Investments have been made in tooling and personnel to improve service response. The new Brazil shop also will help in this regard by freeing up capacity previously reserved for Latin American customers.
- Reduced the cycle time for field-event investigations in the last year by one-third. Additional personnel resources were a major factor in this improvement.
- Investments are being made in monitoring and diagnostics capabilities to warn owner/operators of impending issues.

Engine assessments

One of the most valuable services provided by Strategic Power Systems Inc, Charlotte, to WTUI members is its annual assessment of leading contributors to force outages for each of the engines supported by the Western Turbine Users. The assessments were presented during the breakout sessions. Interestingly, control systems and their components—including controllers, cards, and gas-fuel modulating valves—were the major contributors to forced outages in 2012 for all four fleets—LM2500, LM5000, LM6000, and LMS100.

LM2500. Details on the Top Ten contributors to forced-outage incidents involving the LM2500 were presented to the breakout session chaired by John Baker, plant manager, Riverside Public Utilities, by SPS's Cindy Alicea and Karl Maier. The company's Operational Reliability Analysis Program (ORAP®) provides engineers and analysts the data and tools to develop

and track performance metrics for gas and steam turbines across all OEMs and a broad range of owner/operators.

Alicea and Maier began their presentation by reviewing the performance of LM2500s in electric generation service from January 2008 through December 2012. Note that this study covered the base engine only, not the LM2500+ or the LM2500+G4. Over the five-year evaluation period, peaking machines (service factor of less than 10%) accumulated 44 unit-years of service; cycling (service factor from 10% up to 50%), 146 unit-years; and base-load engines (service factor of 50% and above), 400 unit-years.

Highlights of the analysis, which incorporated data for the 134 LM2500s participating in ORAP, revealed the following:

- Fleet availability (simple-cycle plant), 98.3%.
- Forced-outage factor, 0.8%—with peaking engines at 2.6%.
- Maintenance outage factor, 0.2%.
- Planned outage factor, 0.7%.
- Service factor (the percentage of time units are generating power), 66.1%.

By consensus, the LM2500 is the most versatile engine in GE's aero portfolio. The machine has been uprated and improved several times since its commercial introduction at the dawn of the 1970s and has recorded more than 60-million operating hours over the years. You can find the LM2500 in utility/IPP peaking, cogeneration, and combined-cycle plants, as well as in trailer-mounted emergency/standby packages, drilling-platform service, mechanical-drive applications (gas pipeline compressor drivers, for example), industrial combined heat and power, and marine main propulsion systems.

Interestingly, six of the Top Ten contributors to forced-outage incidents for the LM2500 also are among the LM6000's Top Ten. *Grid instability* is No. 2 on both lists, *external circumstances* is No. 3 on the LM2500 and No. 4 on the LM6000. Other causes of outages common to both engines are *gas-pipeline conditions, distributed control system (DCS),* and *gas-fuel modulating valve.* Failures associated with control systems—controllers, DCSs, and gas-fuel modulating valves—accounted for 37% of the forced outages charged against the Top Ten contributors in 2012, two percentage points higher than for the LM6000.

SPS engineers broke down the Top Ten leader, *controls/controllers/communication,* into subcategories, as they had done for the other engines investigated. It was no surprise that incidents involving control cards was at the top of the list. But for the LM2500 they accounted for 41% of the incidents in the No. 1 category, nearly double the 21% recorded for the LM6000. Logic suggests a higher percentage of "old" cards in the more mature LM2500 fleet.

Loose cabling was second, accounting for 18% forced outages among the subcategories in *controls/controllers/communication.* Causes of the remaining outages were distributed about equally among communication error, software, power supply, human error, testing, and unknown.

Nearly half (44%) of the incidents within the No. 2 *grid instability* category were attributed to "relay trip." *External circumstances,* third among the 10 leading causes of outages, was dominated by a mixed bag of host-site issues for LM2500s in cogeneration service, poor gas quality, and strikes by union employees. More than half of the outages attributed to *gas pipeline conditions,* No. 4, were caused by users or valve issues. *Failure to start* was fifth in the ranking, with root causes not mentioned in virtually all instances.

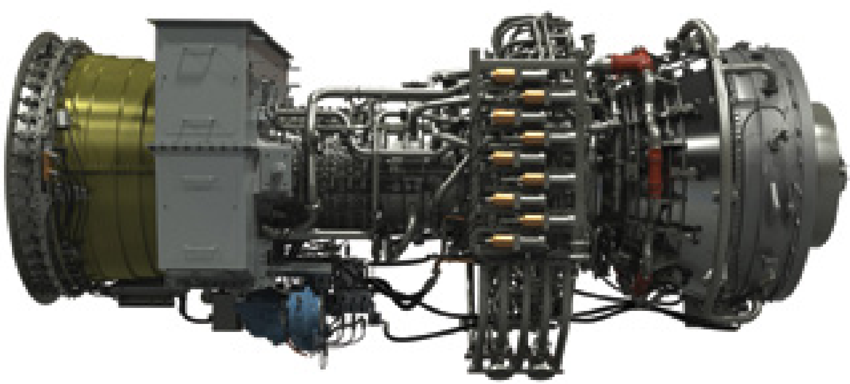
Likewise, causes of outages involving *flame detectors,* No. 6, were unknown in 65% of the incidents. Most of the remainder were attributed to dirty detectors, which operated correctly after cleaning. Nearly half of the failures of the *distributed control system,* No. 7, were caused by communication signal loss. Remainder were divided among out-of-tune, blown fuse, electrical short, and unknown.

Lightning outages amounted to 10 incidents that lasted less than five hours each and five more than 10 hours each. The data submitted to SPS indicated that more than half the outages attributed to issues with the *gas-fuel modulating valve* probably could have been avoided with periodic checking of calibration. *Battery* (125 Vdc) incidents finished at the bottom of the Top Ten. Age was a significant factor, as more than 90% of the failures were related to mismatched battery age/condition.

Only two categories on the Top Ten list of contributors to forced outages by numbers of events—*controls/controllers/communication* and *external circumstances*—made SPS's Top Ten ranking by outage hours. In fact, the average outage for all incidents in categories two through 10 lasted only six and a half hours; the average outage attributed to *controls/controllers/communication* was much longer at 29.5 hours.

The Top Ten list of outage causes by hours of downtime was dominated by issues that rarely occurred. For example, No. 1 on this list was outages caused by incorrect positions of compressor process valves—each of the three incidents averaging five weeks of downtime. Causes of other high-hours outages include compressor, power turbine, airfoil issues, etc—even the lowly exhaust plenum.

LM5000. Tom Christiansen summarized the results of SPS's analysis of LM5000 engines contributing to the ORAP data pool in 2012. The LM5000 breakout session was chaired by Andrew Gundershaug, plant manager,



2. DLE-equipped LM6000 is popular among Western Turbine users

Solano Peakers, Calpine Corp. Fleet simple-cycle availability, according to ORAP, was 94.1%, with the forced-outage factor at 4.1%. Service factor was 37.5% last year. The Top Ten contributors to forced-outage incidents at simple-cycle plants for 2012 were the following:

1. Controls/controllers/modules.
2. Gas-fuel control and regulating valves.
3 Compressor accelerometers.
4. Flame detectors.
5. Engine lubrication system.
6. Steam-injection control and regulating valves.
7. Emissions monitoring system.
8. Gas supply curtailed.
9. Power-turbine lubrication system.
10. Hydraulic control filters.

LM6000. SPS's Steve Giaquinto reviewed the performance of the LM6000 fleet for the past five years during one of the breakout sessions chaired by Kings River's David Merritt. At the end of 2012, the operating LM6000 fleet numbered 798 units, 44% of them participating in ORAP (Fig 2). Highlights of the analysis for this group of engines revealed the following:

- Fleet availability (simple-cycle plant), 96.5%.
- Forced-outage factor, 1.6%.
- Maintenance outage factor, 0.5%.
- Planned outage factor, 1.4%.
- Service factor (the percentage of time units are generating power), 34%.

Over the five-year evaluation period, Giaquinto told the group, peaking machines (service factor of less than 10%) had accumulated 568 unit-years of service; cycling (service factor from 10% up to 50%), 467 unit-years; and base-load engines (service factor of 50% and above), 476 unit-years. The mean time between engine removals for the fleet was 22,283 hours. There were 38 forced removal incidents and 163 scheduled removal events during the period investigated.

Base-load units had the highest mean time between engine removals at 27,639 hours, three times that of peaking units; cycling fell in between. Base-load machines led in forced-removal events with 21 and in scheduled removal incidents with 98.

More than one-third of the 550 incidents that defined The Top Ten contributors to forced-outage incidents in 2012 involved *control systems and their components*. *Controllers and cards* were ranked first with 106 incidents (62 units at 41 sites). Here's a partial breakdown of the subcategory, with the number of incidents in parentheses:

- Card failures (22).
- Engine controller (21)—12 incidents charged against the Mark V, nine against the Mark VI.
- Circuit board (15).
- Loss of communication (14).
- Unidentified controls issues (13).
- Woodward Netcon controller issues (13).

Tied for fifth place in the Top Ten were forced outages of the *distributed control system* and of the *gas fuel modulating valve* with 44 incidents each. For the DCS, 11 incidents were attributed to erratic behavior of the system with undetermined root causes; eight were caused by loose, grounded, or faulty wiring; six were a result of card failures; and five caused by software modifications and logic issues. DCS incidents were reported by 35 units at 21 sites.

Most of the incidents involving gas fuel modulating valves (36) were attributed to calibration problems. Interestingly, one plant reported 38 of the 44 incidents in this category, 32 of which resulted in a failure to start. Total outage hours charged to controls-related incidents totaled 2374 hours.

Grid instability ranked second in the Top Ten with 93 incidents totaling 2201 hours and involving 27 sites. The most costly incident in terms of outage time (1350 hours) involved the sudden shutdown of a main gas valve which dictated a lengthy investigation.

Combustion issues were in third place with 57 incidents involving 20 units at 15 sites. Total outage time was 1447 hours, with a cracked combustion liner accounting for all but 175 of those. Forty incidents were reported as "flameout, causes undetermined/not reported." Another 10 were a result of tuning problems and adjustments. *External circumstances* were ranked fourth with 46 incidents encompassing 1681 hours.

The final four of the Top Ten forced-outage incidents were the following:

- *Gas fuel compressor,* 43 incidents/251 hours.
- *Generator breaker,* 40 incidents/670 hours. Nearly half of the incidents were reported as "failure to open or close" with no additional information provided.
- Aero engine, 39 incidents/516 hours. This is a catch-all category for incidents attributed to the engine but where no information is known or given as to the specific issue forcing the shutdown.
- *Gas supply issues,* 38 incidents/2889 hours, involving 25 units at 15 sites.

The Top Ten contributors to forced-outage hours accounted for 55% of the 46,600 fleet-wide total. The first-place category, *economic decision,* amounted to 7736 outage hours for two incidents: 5448 taken by a unit with severe cracking in the first-stage nozzle segments of the low-pressure turbine; 2288 attributed to degradation of tip material on first-stage blades of the high-pressure turbine of another unit.

No. 2 was *Hurricane Sandy* and the 2890 outage hours it caused—all but 48 at one site, which was down for almost a month. The 2889 outage hours attributed to *gas supply issues* ranked third. More than half of the hours were reported by sites in the Middle East because gas was unavailable. In fourth place was two failures of l*oad compartment vent fans* that caused 2264 outage hours. In the fifth to 10th positions were *grid instability, drive-shaft failure, external circumstances, controllers and cards, emissions,* and *generator neutral ground.*

The LMS100 put up all-star stats, SPS CEO Sal DellaVilla told the user breakout session chaired by Don Haines, who manages the Panoche Energy Center for O&M contractor Wood Group Power Plant Solutions. Fleet performance stats compiled over the last five years:

- Fleet availability, 96.7%.
- Forced-outage factor, 1.5%.
- Maintenance-outage factor, 1.4%.
- Planned-outage factor, 0.4%.
- Service factor (the percentage of time units are generating power), 21.1%.

At the end of 2012, the LMS100 simple-cycle fleet numbered 26 units, 23 of them (88%) participating in the ORAP program. Over the five-year period, DellaVilla told the group, peaking machines had accumulated 22 unit-years of service; cycling, 33; and base-load units, six unit-years. The mean time between engine removals for the fleet was 9813 service hours. There were two forced removal events and nine scheduled removal events during the period investigated. Interestingly, base-load machines had a mean time between engine removals of almost double the fleet average.

Last year, 226 incidents were reported across the fleet, with the Top Ten accounting for 45% of them. *Engine controllers, I/O,* and *software* were at the top of the list with 33 incidents reported—20 of those charged against *communications/controller failures.* However, these failures were short-lived, all 33 accounting for only 127 outage hours.

No. 2 on the list was 17 *combustion-system incidents* averaging 10 outage hours each. The lion's share of the issues (15 of the 17) were attributed to the inability to start because exhaust thermocouple (T48) temperature was not within prescribed limits. *Variable-bleed-valve LVDT incidents* ranked No. 3 with a dozen incidents (only seven hours). All 12 were caused by position-feedback failure of the LVDT. This was a known issue, DellaVilla told the group. It is being addressed in the latest control software upgrades.

Eleven incidents affecting four sites put *grid instability* in fourth place. Liquid-fuel drain valves suffered six incidents with a total outage time of only half an hour. All six were caused by an electrical issue on one unit that prevented the unit from starting. *Inlet-air-filter incidents* tied for the fifth position. All occurred at one site and were caused by high differential pressure. Total outage time: 27 hours.

Five lightning incidents accounting for 491 outage hours were next on the list. Two incidents at one site accounted for about 80% of the total downtime because battery chargers were damaged. The other three incidents at two sites each averaged only about a day and a half.

Rounding out the TopTen were *hot SCR,* five incidents totaling nine hours; *automatic voltage regulator issues* with no known root cause, four incidents totaling 23 hours; and one *lube-oil check valve* that jammed shut three times preventing a unit start in each case.

The Top Ten contributors to forced-outage hours accounted for 72% of the total 3829 outage hours. *Blade damage* in one low-pressure compressor (LPC) accounted for 720 hours. *Lightning,* as noted above, caused 491 hours of lost outage time and was No. 2 on the list. *Variable-bleed-valve damage* on one unit caused 375 hours of downtime. Damage to first-stage LPC blades on one unit initiated a 196-hour outage, putting it in fourth place. However, this outage was extended an additional 30 days because of delays in parts delivery.

Closing out this Top Ten compilation, in order, were *generator breaker arcing, combustion-system issues, faulty transducer in an emergency lube-oil pump starter, faulty accelerometer for the high-pressure turbine, cracked lube-oil vent tube, engine controller/software issues,* and *power-turbine shaft cooling fan.*

Special presentations

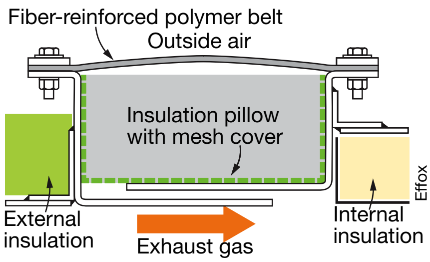
An important part of the technical program at all annual meetings of the Western Turbine Users Inc are the six special presentations on the afternoon of the second day covering topics of importance to attendees not addressed in the engine breakout sessions. These hour-long presentations (including a brief open discussion period after each) are arranged in two time slots, each with three concurrent sessions.

Since it's not possible for any delegate to attend more than two presentations, WTUI Webmaster Wayne Feragen, a plant manager for E I Colton LLC, posts the PowerPoints in the user-only section of the organization's website at www.wtui.com. Owner/operators of LM engines not already registered on the website are encouraged by the officers and board of directors to sign up to access this information. Benefits of WTUI membership also include participation in the group's discussion forum.

Summaries of four presentations made available to the editors follow. Note that two address Rankine cycle concerns because many cogeneration and combined-cycle plants are powered by LM2500s, LM5000s, and LM6000s. In fact, three WTUI breakout chairs or board members manage LM combined cycles: John Baker, Brad Hans, and Don Stahl, Pueblo (Colo) Airport Generating Station.

Combined cycles with LM6000s have emerged as a popular option among power producers looking for higher efficiency and greater flexibility to compete against frame and other generation options when requirements are in the nominal 100- to 350-MW

3, 4. Hot expansion joint (above) couples exhaust end of the gas turbine to the transition piece for the heat-recovery steam generator. A typical expansion-joint arrangement is above. Pillow must be kept intact to prevent leakage of exhaust gas. Note that the fiber-reinforced polymer belt at the top is only able to withstand temperatures up to about 500F



range. Recent examples: (1) The 3 × 1 LM6000-powered combined cycle commissioned earlier this year by Chugach Electric Association Inc and Anchorage Municipal Light & Power, and (2) Calpine Corp's conversion of a four-unit LM6000 peaking plant in California to combined cycle, expected in service this summer.

HRSG inlet-duct challenges

Ned Congdon, PE, one of HRST Inc's (Eden Prairie, Minn) top field experts on heat-recovery steam generators, crammed a half-day seminar into the hour he had available, leaving an audience of more than 75 lots to think about when they returned to their plants.

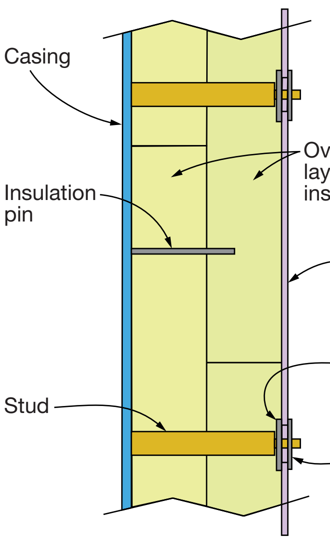
There was considerable pent up demand for the information Congdon shared because no other industry forum effectively serves users with small drum-type and once-through HRSGs—such as those supplied by WTUI exhibitors Express Integrated Technologies Inc, Innovative Steam Technologies, and Rentech Boiler Systems Inc (represented at WTUI by California-based AHM Associates Inc).

After a brief summary of HRST's specialty products and services, the hands-on boiler troubleshooter and solutions provider delved into the nitty gritty of HRSG inlet ducts—focusing on expansion joints and liner and insulation systems. Not many topics more mundane than inlet ducts, but healthy expansion joints and liner systems are critical to top performance and safe operation. Consider that failure to maintain liner integrity can mean insulation going downstream and fouling catalyst and finned heat-transfer surfaces. Casing hot spots caused by insulation loss also are safety hazards. Likewise, expansion-joint failures can create safety hazards as well as allow gas-turbine exhaust to bypass emissions controls.

Congdon didn't spend much time on expansion joints. He focused his attention on the hot-end joint between the gas turbine exhaust ductwork and transition section in front of the HRSG (Fig 3), barely mentioning the cold-end joint between the boiler and stack because of time constraints.

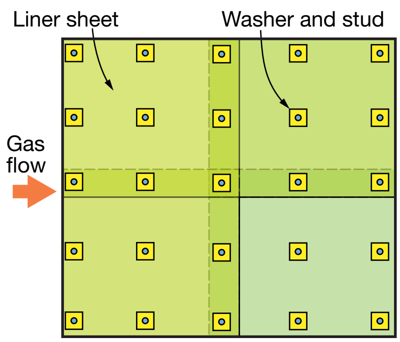
Fig 4 is a cutaway drawing of a typical hot-end expansion joint.

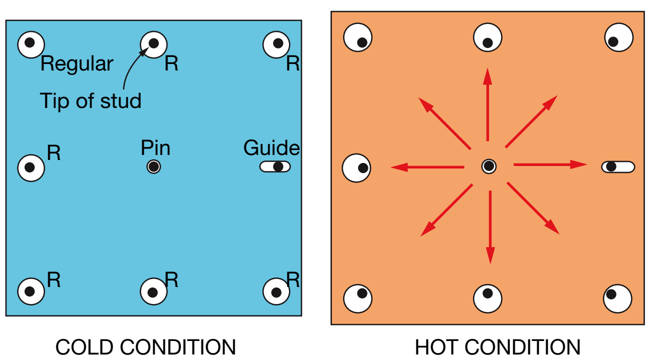
The boiler expert stressed the need to maintain the integrity of the insulation pillow to maintain a leak-tight joint. The fabric belt at the top of the joint shown is designed only for temperatures up to 500F, he said, and it won't hold up for long against flue gas, which at this location is at 1000F or more.



5. Typical insulation arrangement for an HRSG consists of overlapped layers of ceramic fiber sandwiched between the outer casing and inner liner (left)

6. Liner sheets are lapped, like fish scales, in the direction of gas flow (below)





7. Liner sheet in cold condition at left reveals a clear space of about 0.625 in. between pin and the edge of the liner hole. Hot condition at right shows holes have moved outward

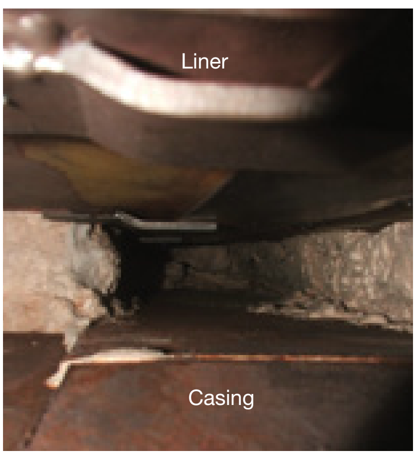
Two issues with expansion joints of this design known to Congdon were failure of the protective flashing at the bottom of the assembly attributed to the turbulent high-temperature environment and destruction of the pillow's mesh cover because of improper material selection. He suggested a bolted solution, rather than a welded one, when the plate must be replaced—this to reduce the likelihood of the shield cracking in service.

Switching subjects, Congdon said liner systems generally are designed like the one illustrated in Fig 5, with ceramic-fiber blanket insulation compressed between an outer casing of plate steel and floating-sheet steel inner liner. Note that the liner sheets are lapped, like fish scales, in the direction of gas flow (Fig 6).

Important: Expansion and contraction of the liner sheets demand that adequate space be provided between the pins and liner plate to assure system integrity. Holes in the liner plates normally are 2 in. in diameter and the overlap between adjacent plants typically is 4 in. Recommendation is that in the cold condition, there should be about 0.625 in. of clear space between the pin and the edge of the hole in all directions (Fig 7).

Congdon advised conducting a thorough HRSG inspection yearly, and checking the inlet- and firing-duct liners at every opportunity. The latter obviously applies only to units equipped with duct burners. Look for loose and cracked liner panels near the GT, he advised, as well as for spinning washers and exposed insulation. This was said to be especially important at plants with LM6000s because of the engine's reputation for highly turbulent exhaust flow. Con-

8, 9. Washer free to spin after spot weld failed scribed a circle in liner plate (left). If spinning is allowed to continue, a slot can be cut in the washer (right) and/or the bolt head cut off



10. Hot spots arise when insulation migrates from between the liner and casing

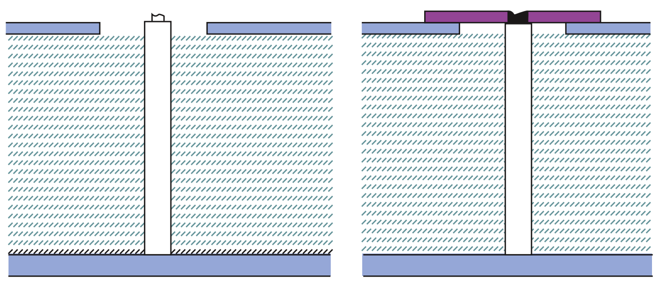
gdon urged all in the room to fix inlet-duct liner problems without delay—and not to weld liner sheets together.

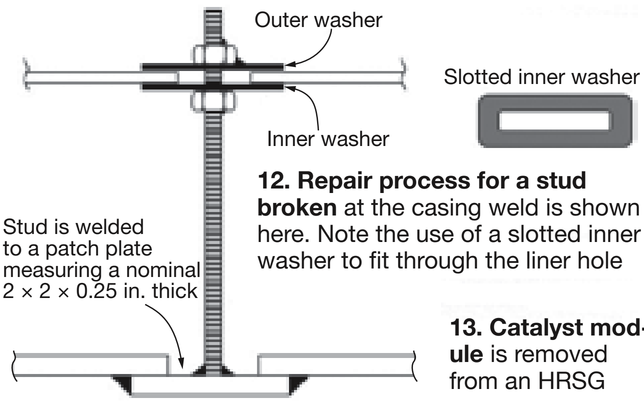
Spinning washers, both external to the liner plate and underneath it, can do considerable damage. Fig 8 shows an external washer free to spin because the spot weld holding the stud nut to the washer failed. Note the circle scribed in the liner plate by the spinning washer. If spinning were allowed to continue, a slot would likely be cut through the washer (Fig 9) and/or the top of the bolt would be sliced off. When the liner fails and insulation escapes, hot spots are created (Fig 10). Congdon recommended the relatively simple plug-welding procedure illustrated in Fig 11 to attach washer to a stud in cases where stud tips are cut off.

When a stud is broken at the casing weld, the fix illustrated in Fig 12 is recommended. The replacement stud should be of Type 304 stainless steel, or Type 409, and 0.75 or 0.875 in. in diameter. For rework required in high-turbulence areas, Congdon suggested the following:

- Add studs on the perimeter, and especially on the leading edge. HRST engineers use a stud spacing of 12 in. or less.
- Increase stud strength. Consider a stud of larger diameter than installed originally.

11. Liner studs must be repaired when they fail, to protect insulation integrity. Fixing a missing stud tip is relatively simple as plug weld at right illustrates





12. Repair process for a stud broken at the casing weld is shown here. Note the use of a slotted inner washer to fit through the liner hole

13. Catalyst module is removed from an HRSG

- Use a full circumferential weld between the stud and outer washer; a tack weld between the stud and inner washer.
- Increase liner thickness to 10 gage.
- Compress insulation under the liner. Never use mineral wool in HRSG inlet ducts.
- If the boiler casing is vibrating visibly, add external stiffeners.

Integrating SCR and CO catalysts

Many in the ageing workforce remember gas turbines without SCRs. When NO_x emissions were first targeted by federal, state, and local environmental agencies, owner/operators opted for water injection to quench flame temperature and reduce the production of thermal NO_x. That was acceptable for a while, but as pollutant emissions limits were ratcheted downward, the OEMs developed more prudent dry low-NO_x combustion systems.

However, low is never quite low enough when it comes to emissions and SCRs were installed to reduce NO_x out the stack to as low as 2 ppm in some areas. Along the way, carbon monoxide was blacklisted and oxidation catalyst was installed to keep CO emissions below about 10 ppm, generally speaking.

Nathan White, director of business development for Haldor Topsoe Inc, the Danish company's US subsidiary, discussed the technology of catalysts for NO_x- and CO-emissions control in his hour before LM owners and operators. The PowerPoint he spoke from, which is available for viewing by registered Western Turbine users at www.wtui.com, was developed by Niklas Jakobsson and Francesco Castellino.

White began with a review of basic catalyst structures, offered chemical equations to characterize SCR and CO oxidation reactions, and discussed how catalysts work. Next, he showed SCR arrangements for simple-cycle GTs—those with tempering air and those without—describing the differences between low- and high-temperature catalysts and where each fits.

White also offered several arrangements of SCR and CO catalyst modules in heat-recovery steam generators—two with the CO catalyst located before the SCR in the direction of flow, two with the SCR located first (Fig 13). The latter arrangement certainly came as a surprise to some in the room because the prevailing industry wisdom is that CO catalyst should be located ahead of the SCR, where the GT exhaust-gas temperature is higher—thereby minimizing the volume of noble-metal CO catalyst typically used in this service and maximizing oxidation activity.

What differentiated this presentation from many others the editors have heard was that the SCR and CO catalysts were approached complementarily—as an emissions control system. Most presentations focus on the attributes of a given CO catalyst, or SCR catalyst, to satisfy specific requirements—an approach certainly of value to personnel at plants challenged to reduce their emissions profiles. But in some retrofit situations, and for new plants in particular, the system approach presented by White may be preferable given the benefits he cited.

White presented the features and benefits of Haldor Topsoe's DNX® GT-series of catalysts tailored specifically for gas-turbine service. They comprise a range of product offerings for NO_x reduction and CO oxidation. The SCR catalysts in this series, he said, have physical and chemical features that promote high activity and low pressure drop. The CO-oxidation catalysts, designated GTC, originate from the DNX SCR catalyst and are characterized as dual-function catalysts—that is, they are active in the SCR reaction as well as in CO and VOC oxidation.

The dual-function nature of the GTC CO-oxidation catalyst allows its location downstream of the SCR in the HRSG, permitting operation of the latter at a higher-than-traditional outlet NO_x and at a higher-than-design ammonia slip. The GTC catalyst completes the NO_x reduction process while oxidizing CO. A significant benefit of this approach is said to be a reduction in SCR catalyst volume. Also, locating the oxidation catalyst in a region of lower temperature reduces pressure drop because of lower volumetric gas flow.

More specifically, the work done by Jakobsson and his colleagues at Haldor Topsoe concludes the following, depending on HRSG layout: Installing the DNX GT and GTC catalysts in series and locating the CO-oxidation catalyst downstream of the SCR can reduce SCR catalyst volume by more than 40% and lower the total pressure drop across the catalyst beds by 25% or more.

Ammonia absorption chiller

One of the first things you learn about gas turbines, in school or on the deck plates, is that their performance drops off rapidly as ambient air temperature increases above about 60F; also, that you can restore at least some lost performance by cooling compressor inlet air. At electric generating stations, cooling generally is accomplished by evaporation, using either wetted media or fogging technology, or by mechanical refrigeration systems with motor-driven compressors. Much has been written on these subjects.

Absorption refrigeration systems are another option, but these usually are specified for relatively small plants serving industry and/or institutions that have a source of waste heat or low-pressure steam to drive the process. The majority of absorption systems use water as the refrigerant and lithium bromide as the absorbent salt. Alternatively, ammonia can be used as the refrigerant and water as the absorbent.

Chris Mieckowski and Luke Buntz of Kiewit reminded users of the benefits of ammonia absorption conditioning. Compared to evaporative cooling, Mieckowski said the benefits offered by Kiewit's Arctic ammonia absorption product include the flexibility to heat or chill with the same system and the ability to serve at sites with no water. However, as noted above, a heat source is required, and Arctic's capital cost is higher than for evaporative cooling.

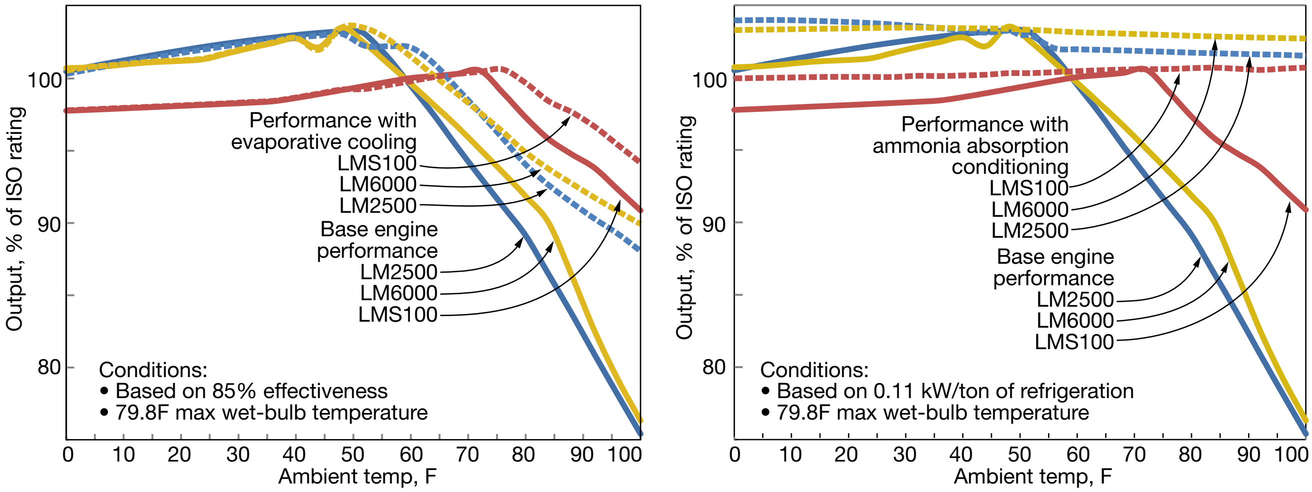
The curves presented in Figs 14 and 15 compare the cooling capability of Arctic to the evaporative alternative for the LM2500, LM6000, and LMS100. Note that the output of each engine remains at or above its ISO rating at temperatures up to 100F with the absorption system in service.

Wrapping up, the product manager said the absorption system offers the greatest "amount of flexibility to operate a turbine in the most economical sense—that is, maximum output or highest efficiency/minimum emissions." A detailed economic analysis factoring in such variables as output needed in hot weather, requirements for performance heating, parasitic load, O&M costs, etc, is recommended to determine if Arctic fits your situation.

ORAP simplifies NERC reporting

Some things you can't say too many times. One of them: As of 2013, all thermal generating units having a gross nameplate rating above 20 MVA, as well as a direct connection to the bulk power system at more than 100 kV, must report certain operating information to the North American Electric Reliability Corp. NERC is responsible to FERC for improving the reliability and security of the bulk power system.

Other generating facilities subject to NERC reporting include black-start resources material to, and designated a part of, a transmission operator's restoration plan; plus, generating units material to the reliability of the bulk power system.



14, 15. Evaporative cooling improves gas turbine performance, as most readers are well aware (left), but ammonia absorption conditioning does the same job more effectively (right). What's optimal for your plant depends on its location, annual operating hours, capital cost, and other factors

To help users come up to speed on a subject that many owner/operators knew little about, Charlotte-based Strategic Power Systems Inc (SPS) participated in the Special Technical Presentations portion of the WTUI program and also sponsored a special seminar at the San Diego Convention Center the afternoon after the Western Turbine meeting officially closed.

During the latter, presentations by SPS CEO Sal DellaVilla and Senior VP Tom Christiansen, and Mike Curley, president of Generation Consulting Services LLC (previously manager of NERC GADS Services), covered among other things, NERC GADS's reporting requirements and how ORAP users could do that through SPS.

The trio began by tracing the ongoing complementary relationship between NERC and SPS that extends over more than 25 years. Each organization uses some of the same data for different purposes. NERC electronically and automatically verifies information supplied by generators to support reliable operation of the bulk power system. By contrast, SPS captures more detailed data, which is reviewed by engineers for accuracy and vetted for quality, to support industry benchmarking efforts and other activities.

The accuracy of data gathered by SPS is such that NERC has designated the company a Designated Reporting Entity (DRE), meaning it can submit data directly to NERC on behalf of its ORAP users. SPS is the only non-ISO (Independent System Operator) to have this distinction. The benefits to SPS clients are obvious: Plant personnel have one less reporting requirement, data are traceable and verifiable, SPS is a resource for clients if NERC has questions. Currently, more than 100 ORAP-participant sites report data to NERC GADS through SPS.

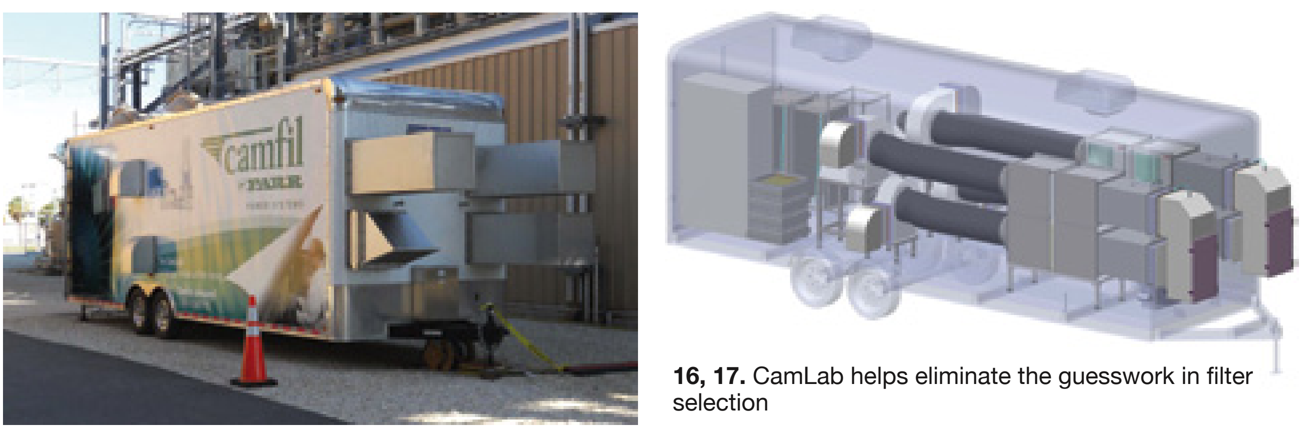
HEPA filters still performing well

A few years ago, when a frame OEM gave suppliers of HEPA filters a big assist by strongly suggesting water not be used in engines of its manufacture for boosting gas-turbine output and/or compressor cleaning, several high-runtime users told the editors they did not expect to get more than a year or two from a set of HEPAs.

At that time, HEPA filters cost as much as four or five times the asking price for conventional panel filters. With little hard data on HEPA-filter performance in powerplant and pipeline service, most GT owners were reluctant to pay such a premium for a product unproven in their industry. That's no longer generally true.

In his Special Technical Presentation at the 2012 Western Turbine conference, Rob McMahon of Alliance Pipeline gave HEPA filters a "thumbs up" based on two years of experience on an LM2500+G4 at its Windfall pumping station and on an LM2500 at Kerrobert in west-central Saskatchewan. So positive was his company's assessment of HEPA value that it decided to switch all of its GTs to the more efficient filters. Incidentally, the Alliance G4, the first of its class to enter commercial service, was equipped with filters from W L Gore & Associates that did not have the now-recommended coalescer wrap. Filters for the other 18 Alliance GTs have the coalescer wrap.

The editors caught up with McMa-



16, 17. CamLab helps eliminate the guesswork in filter selection hon just before the 2013 meeting to get a current assessment of performance. The two units he spoke about last year were now approaching three years of service and the pressure drop across the filters on each turbine, monitored by the company's M&D center, is virtually the same as it was in 2012—about 1.5 in. H_2O. McMahon said the only pressure-drop excursions experienced were caused by hoar frost and they were short-lived.

A user wouldn't be doing his or her job without assuming the good news was the result of cleaner air than most GT owner/operators might have access to. Not true, McMahon said. The Kerrobert unit is in an agricultural area and the delta p is the same as it is for units that don't ingest large amounts of airborne particulates. Yet another Alliance engine is in a section of Minnesota with a light peat-type soil. Results are the same.

McMahon said his company wanted to eliminate water washing to avoid shutdowns for compressor cleaning. He pointed out that compressor seals do not tolerate start/stop operation well and that being able to run continuously boosts reliability and availability; plus it eliminates the cost of manpower, water, and chemicals for washing. McMahon is looking forward to the G4 overhaul in January 2014 to see if any other benefits accrue from the use of HEPA filters.

Exhibit hall

Control system retrofits for aeros, LM6000s in particular, were a top discussion topic among users walking the exhibit hall. The Western Turbine meeting features the most robust exhibition among the user groups serving gas turbine owners and operators with well over 150 companies participating. WTUI's expo also offers more face time with vendors than the other groups; no other activities are on the schedule for nine of the 20 hours the exhibit hall is open.

The ageing LM6000 fleet has many units with control systems facing obsolescence and/or increased scrutiny by grid operators and the North American Electric Reliability Corp (NERC). Competition for retrofit business is keen and the OEM and third-party suppliers were at the San Diego Convention Center talking up recent successes. Here are some of the things CCJ's editors learned:

Wood Group GTS, which introduced its latest control system upgrade for the LM6000 last fall, is offering an integrated solution to replace the original proprietary hardware and software with an open-architecture design. Engineers at the company's booth stressed that the new system enables operators to reconfigure turbine operation in-house without incurring costly support and service charges. They said the company would support the control system, which is based on Rockwell Automation's Plant PAx™ platform, to the degree users want.

The editors were told Wood Group GTS has completed over 500 installations using proven Rockwell Automation technology. Platforms the company considers as candidates for its new upgrade solution include NetCon™, Micronet™, and GE Mark V™ and Mark VI™. Several owners already are operating LM6000s with this system, having benefitted from close relationships with the supplier for pre-release installations.

Among the first users internationally are plants in Brazil and Australia. In the US, Jonesboro (Ark) City Water & Light replaced the Woodward NetCon 5000 controls on one of its LM6000s. Similarly, Wood Group upgraded, at the end of last year, an LM6000 equipped with Mark VLM controls for Southwest Generation Operating Co, Las Vegas.

Wunderlich-Malec, a Phoenix-based controls integrator with a booth on the show floor alongside Wood Group, also was involved in the controls upgrade project at Southwest Gen, providing a balance-of-plant (BOP) solution. The editors learned from users that the company provides controls support on a continuing basis for several LM owner/operators.

Emerson Process Management Power & Water Solutions recently received a contract from Ameren-Missouri to retrofit four LM6000s at Pinckneyville Generating Station with its Ovation™ control system. Emerson will replace Woodward NetCon 5000 controls on the engines, as well as Rockwell/Allen-Bradley PLC5/SLC BOP controls and the Wonderware HMIs serving the gas turbines and BOP. Interestingly, the Ovation system will interface with four GE 6B frame engines at the site equipped with Mark V and Cimplicity HMI controls, plus Harris RTUs, fire alarm systems, emissions monitoring equipment, and the PI-API node.

GE Power & Water, recently completed the retrofit of four 2004-vintage LM6000s at CPS Energy's (San Antonio) Leon Creek Power Plant from Mark VI Millennium to Mark VIe.

CSE, HPI, Petrotech. LM6000s and LM2500s were not the only engines discussed regarding control system upgrades. CSE Engineering Inc and representatives of Wellhead Electric Co met with the editors to review the successful conversion of a Wellhead FT4 TwinPac from a Hamilton Standard SPC (Servo Position Control) system with analog fuel controls to a PLC-based solution configured by CSE engineers.

Representatives of HPI LLC, which calls Houston home in the US, discussed their company's involvement in the replacement of OEM controls on two FT8 TwinPacs at Klamath (Ore) Cogeneration Plant with a standalone ABB DCS featuring open-code architecture (see p 32 for details).

Steve Cernik talked up Petrotech Inc's recent success in upgrading three ageing Frame 5 engines at Kentucky Utilities Co from early Speedtronic to the Houston-based company's PLC-based solution.

Don't get the impression that only control-system suppliers and integrators were present in the exhibition hall. Far from it: Products and services from A to Z were on display. Examples include the following:

- Boilers and related services were offered by Babcock & Wilcox, Bremco, Express Integrated Technologies, HRST, Hamon Deltak, Innovative Steam Technologies, and Nationwide Boiler, among others. An interesting new product in this sector was a collaborative development effort between HRST and G R Werth & Associates (Duct Balloon) to bring to market an inflatable stack damper that can be deployed and retracted with the simple push of a button in the control room. System was in beta testing at two plants at the time of the meeting.
- Lube-oil and LO filter suppliers also were easy to find on the expo floor—including, Hy-Pro Filtration, C C Jensen Oil Maintenance, and Parker Hannifin. The latest offering in this category may be Jensen's Varnish Removal Unit, which uses enhanced filter discs to remove varnish to very low levels.
- Air inlet filters were visible on virtually every aisle. Among the suppliers were AAF International, Advanced Filtration Concepts, Braden Manufacturing, Camfil Farr Power Systems, Donaldson, DRB Industries, W L Gore & Associates, Pneumafil, and TVS Filters. Most interesting service on display, perhaps, was Camfil Farr's lab on wheels (The CamLab), which allow users to evaluate in real time under the actual operating conditions at their sites, alternative filtration solutions simultaneously with no risk to operating equipment (Figs 16, 17). CCJ

Benefit professionally by attending a user-group meeting this fall

The fall calendar reveals five user-group meetings focused on serving owner/operators of generating facilities powered by gas turbines. It's in your best interest to attend at least one; all are first-rate conferences. The learning experience offered is incomparable. The thumbnails below, arranged by date, direct you to program and other necessary information.

September 3-5

Arizona Biltmore, Phoenix
Visit www.ccusers.org.

Distinguishing characteristics: Technical presentations and discussion on the integrated combined cycle with a focus on equipment and systems other than the gas turbine; no exhibition, no tours. Attendees are a nominal 50/50 mixture of users and others—including equipment suppliers, field-service firms, consultants, EPC contractors, etc).

Key sessions:
- Strategic and financial planning.
- Experience with fast-start plants.
- Challenges of modern control systems.
- Electrical, with emphasis on generators and transformers.
- Operating challenges and changing paradigms.
- Water management, cycle chemistry, and corrosion control.
- Performance software, diagnostic monitoring and assessment.
- Safety management

Sponsors: InStep Software LLC, Siemens Energy Inc, GP Strategies, Wood Group GTS, Nalco Company, Toshiba, Babcock Power, and Emerson Process Management.

September 8-12

The Coeur d'Alene (Idaho) Resort
Visit www.ctotf.org.

Distinguishing characteristics: The most demanding user group meeting in the industry. Workaholics are never disappointed; neither are those who like to eat well. Days begin with breakfast at 7 am and end at 9 pm. This is a user-only meeting with sessions closed to all but owner/operators. CTOTF, now in its 38th year, is the granddaddy of gas-turbine users groups. Its content spans all gas-turbine types and includes a robust high-voltage electrical program as well as detailed coverage of regulatory and compliance issues.

Between Monday morning at 8 am and Thursday at 5 pm, attendees have the opportunity to participate in 14 roundtables (sessions) totaling 68 hours of presentation and discussion time (there are multiple roundtables in some time slots), plus a trade show Monday evening and special three-hour night-time sessions on Tuesday (compressor maintenance and repair) and Wednesday (generator operational theory). All evening programs include dinner.

Key roundtables:
- Industry issues.
- O&M and business practices.
- GE F class.
- Regulatory and compliance.

- Solar turbines.
- Alstom.
- GE E and legacy class.
- Combined cycle.
- Siemens V and H class.
- GE aero.
- Mitsubishi.
- Pratt & Whitney.
- Generator, HV electrical, I&C.
- Siemens F and G class.

Sponsors: Super Champions are 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, and Young & Franklin Inc.

Champions are 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, and Veracity Technology Solutions.

October 14-17

Red Rock Resort & Spa, Summerlin, Nev
Visit www.acc-usersgroup.org

Distinguishing characteristics. Presentations and discussions focus on the design, operation, and maintenance of air-cooled condensers—that's it. If you are responsible for one or more ACCs anywhere in the world, this is the meeting for you. Speakers will offer both a global and local perspective. Attendees are nominal 50/50 mixture of users and others—including equipment suppliers, field-service firms, consultants, EPC contractors, etc). There is no exhibition with this meeting, but plant tours have been arranged with NV Energy, the US leader in terms of number of dry cooling cells in operation.

Key sessions:
- Operation and maintenance.
- Design and performance.
- Chemistry and corrosion.

Sponsors include Howden, Evapco-BLCT Inc, and Conco Systems Inc.

October 21-23

IAGT

Fairmont Banff Springs, Alberta, Canada
Visit www.iagtcommittee.com

Distinguishing characteristics. The IAGT (Industrial Application of Gas Turbines) Committee, formed in 1973, operates today under the sponsorship of the Canadian Gas Assn and the National Research Council. Its specific functions relate to the organization of a biennial technical symposium for the presentation of technical papers and discussion panels covering all aspects of industrial gas turbine operation, as well as providing a forum for reviewing directives, guidelines, codes, and practices, as issued by regulatory agencies, which impact directly on the application of GTs. Users, as well as others aligned with the electric power and gas transmission industries, are invited to attend.

Key sessions. This meeting does not have a standard format for sessions—such as compressors, turbines, etc. However, IAGT offers specific training sessions, which are integrated into the meeting. These include: gas-turbine basics, cogen and combined cycles, LNG, emissions regulations and emissions control, repair technologies, controls upgrades.

Sponsors: IST, Union Gas, Spectra Energy, and Rolls-Royce.

October 22-24

Hyatt Regency Monterey (Calif)
Visit http://ge7ea.users-groups.com

Distinguishing characteristics. The 7EA Users Group has been meeting annually for more than 20 years.

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Presentations and discussions generally pertain to the GE 7B-E engine models, as well as to the EA. A seasoned steering committee typically keeps you guessing on specific topics that will be covered until a few weeks from the meeting, but it never disappoints on content. Follow the website for specifics, but be sure to reserve a seat by registering. This is a user-only meeting with sessions closed to all but owner/operators. A vendor fair is incorporated into the program.

Key sessions. This meeting does not have a standard format for sessions, like the IAGT.

Sponsor names have not yet been made public.

Eight bells

Felix A Fuentes stood his final watch on Earth, as an operations supervisor for Duke Energy at a combined-cycle plant in Florida, last January 9. The editors learned of Fuentes' sudden passing at age 48 in early April while visiting with his former colleagues at NV Energy's Walter M Higgins Generating Station in Primm, Nev. It was a shock. Fuentes was a well-conditioned knowledgeable and caring person always willing to share his expertise in combined-cycle operations—and dog training—with his coworkers as well the editors.

Everyone the CCJ spoke with had only good things to say about the man, born in the Bronx in the shadow of Yankee Stadium and raised in New Jersey, who went on to serve nearly five years in the US Air Force as a power-systems troubleshooter. After leaving the service in early 1987, Fuentes migrated through a series of hands-on positions, growing with each step: lead mechanic for FedEx, CRO at the Linden (NJ) Cogen Plant across from New York City, shift supervisor at Ogden Martin Systems of Union, senior CRO at Eldorado Energy, and operations manager at Higgins.

Felix Fuentes (left) walks CCJ Editor Bob Schwieger through the complexities of an outage to replace turbine blades at NV Energy's Higgins Station

Fuentes began working at Higgins before it was commissioned by Reliant Energy as the Bighorn Power Plant in 2004. He hired the plant's O&M staff, initiated its operator training and qualification program, implemented standard operating procedures and work management practices, and championed excellence in both safety and operations. Fuentes transitioned to Progress Energy (now Duke Energy) in March 2011 to be closer to family.

The editors heard from several members of NV Energy's close-knit generation organization about how they remembered Felix the leader, the mentor, the friend. The following thoughts were excerpted from about 1000 words of commentary provided by Kevin Newcomb, maintenance manager, Edward W Clark Generating Station; Jose Otero and Chris Jackson, plant operators at Higgins, Dave Rettke, mechanical maintenance specialist at Higgins, and Ron McCallum, production manager, Harry Allen Generating Station.

Felix. . .would go to any length to ensure plant reliability and safety. . .was a great encourager. . .understood the importance of having a well-documented and well–maintained operator training program. . .always said "good morning" and always asked if any issues were reported by the night shift; plus, he always said "good bye" on his way out of the plant in the afternoon and asked if there were any issues of concern before he left the site.

Believed "dignity and respect" were due everyone, no matter what their position. . .periodically would have his lunch in the control room and share some light moments and Felixisms. . .would always end performance reviews with the offer of guidance and help. . .encouraged operators to make decisions when necessary after ensuring safety of personnel and equipment. . .always asked the CRO's permission before touching a control screen, even though he was the man in charge. . .had a way of making people work well together and when he was in the room there usually was laughter.

Was one of the most positive and engaged managers I've worked with. . .cared about the people in the plant and was the first to point out the best in everybody. . .had a sense of humor that would brighten your day. . .always available to listen to professional and personal issues at the plant and from home. . .gave me a chance to get back into the workforce and start over. . .supported his "guys" on every decision they made—right or wrong.

Organization news

TICA, the Turbine Inlet Cooling Assn, Naperville, Ill, has extended its offer of complimentary membership (one year) and participation in its online forum to gas-turbine owner/operators. The group also sponsors webinars on turbine inlet cooling (TIC) technologies for users. Visit http://turbineinletcooling.org for more information and access to a comprehensive TIC bibliography as well as a list of installations. The website also has an online calculator for evaluating the performance of various cooling technologies.

IGTC, the International Generator Technical Community, reports that it now has 1500 members. The webmaster paused at this milestone to thank the many generator experts who have shared their time, ideas, and expertise to create and sustain the largest online community of generator subject-matter experts in the world. If this is news to you, go to www.generatortechnicalforum.org and benefit by registering for access. And if you haven't visited the site for a few months, be sure to check out the new "Generator Evaluation Memo" (GEM) section of the IGTC Resource Center. This growing body of information was developed with the invaluable assistance of consultant Clyde Maughan. It offers well-illustrated bulletins on more than 20 generator failure modes. Others are encouraged to add to the collection.

People

Paul White, respected throughout the industry for his deep knowledge of gas-turbine design, operation, and maintenance, and for his mentoring of tomorrow's industry leaders, is appointed Consulting Engineer by Dominion Resources Services Inc. White, who was the company's manager of O&M, will be transitioning into retirement over the next couple of years. John Gundy has been promoted to Manager F and H Engineering, replacing Paul. White's new responsibilities include new generation technology, LTSA development and administration for Dominion's latest combined cycles, and knowledge transfer/mentoring.

Andrea Colombo, is appointed Chromalloy's VP Energy, a new position. He comes to the Sequa Corp subsidiary from GE Oil & Gas.

Dr Haldor Topsoe, celebrates a century of life. The centenarian is best known in this industry sector for his pioneering work in the development of catalysts for reducing emissions of NO_x and CO from stationary combustion sources—including gas turbines and coal-fired boilers.

Sue Comiskey, director of communications for Emerson Process Management Power & Water Solutions, opts for the good life over work, taking early retirement despite pleas to the contrary by company and industry colleagues.

Duncan Brown joins NAES Corp as director of corporate development for engineering services. His background includes senior positions at Science Applications International Corp, Calpine Corp, and DesignPower New Zealand Ltd.

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