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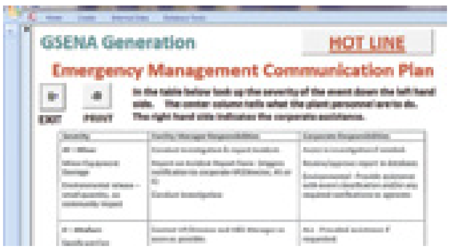

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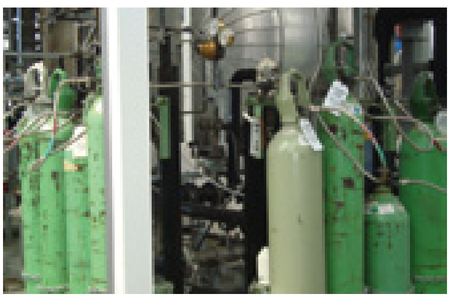

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INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

COMMENTARY

Why the energy industry should invest in high-school education

The demand for new technologies and energy have created two parallel workforce phenomena— the development of new careers in the energy industry and the increased competency skills for technicians. From construction to business management, energy management issues are growing very important in a number of career pathways.

These jobs are high-skill, high-wage and in high demand. Unfortunately, there is a shortage of individuals with the necessary skills in energy practices, and employers seeking more technical workers often face bleak prospects. In many instances, while the technologies to support the energy industry have been or are being created, the industry lacks the skilled workforce necessary to implement and use these technologies. To some capacity, the need for human capital is proving to be a barrier to the continued growth and expansion in energy efficiency and sustainability.

Career and Technical Education (CTE) programs are poised and ready to ease the workforce bottleneck that could limit job growth in the energy sector and meet the need for energy job training across career areas. Community and political leaders, along with local business and industry, should look to CTE programs as the answer to this workforce challenge, and aim to invest in and expand these programs and opportunities so that even more students can participate. CTE programs are flexible and responsive to economic and workforce needs, placing them in a prime position to serve the growing and evolving energy industry.

The majority of our CTE programs include science, technology, and mathematics instruction coordinated with academic instruction; clearly articulated pathways to careers and postsecondary education; and some opportunities for work-based learning. CTE offers early exposure to students regarding energy career options through curriculum integration, provides the "cutting edge" training necessary to ensure future employees meet workforce pipeline needs. At all levels of education, from career exploration to specific job training, CTE has an essential role to play in energy and environmental sectors.

Not only does our economy need high-school and community-college graduates to fill nearly 1 million Science, Technology, Engineering, and Math (STEM) jobs in the next decade, but those students will reap enormous benefits from an education that prepares them for these jobs. The STEM report available at ccj-online.com/stem finds that people with a high-school diploma or less have higher lifetime earnings working in STEM jobs than in any other field. STEM jobs also pay more than all other fields for people with an associate's degree, some college, or a postsecondary certificate.

We in the energy industry need to become important players in promoting STEM in high school. Around the country, CTE programs focused on a wide variety of energy technology ideas and practices have stepped up to ensure the continued pipeline of skilled workers with a strong knowledge foundation. These programs should be recognized for their leadership, and expanded so that even more students can participate. Community and political leaders, along with local business and industry, should look to CTE programs as the answer to the future energy workforce challenge.

Dr Robert Mayfield
Chairman: Virginia Dept of Education Career and Technical Education Advisory Committee
Plant Manager: Tenaska Virginia Generating Station

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Wind slips, gas dominates announced US capacity additions

With small marginal power-industry growth, current renewable mandates consume a relatively large portion of new generation leaving traditional fossil fuels less room to expand. Low gas prices, upcoming environmental regulations, and a mini-boom in GT-based capacity announcements help gas gain market share at coal's expense

By Adam Picketts, Energy Ventures Analysis Inc

Coal, combined-cycle, and renewable fleets will experience the most dramatic capacity shifts from 2011 through 2018. The Cross-State Air Pollution Rule (CSAPR), Mercury and Air Toxics Standards (MATS), new-unit capital costs, Renewable Portfolio Standards (RPS), and sluggish electricity market growth are the drivers of near-term US capacity dynamics. As mandates set aside nearly 100% of generation growth to renewables, gas will expand its base-load market share by displacing coal generation.

Across all fuels and technologies, capacity announcements for calendar years 2011-2018 total 163.1 GW (Fig 1). During this same period announced retirements total 40.9 GW, leaving net US capacity additions at 122.1 GW. GT-based combined-cycle, cogeneration, and simple-cycle plants account for 43% of this total. Although announced nameplate wind capacity is 51.7 GW, EVA estimates that only 25 GW actually will be installed (Sidebar 1). Also to wind's disadvantage, only roughly 10% of this nameplate capacity will be credited as firm capacity. GT technologies will be required to help fill the void between installed and credited wind capacity.

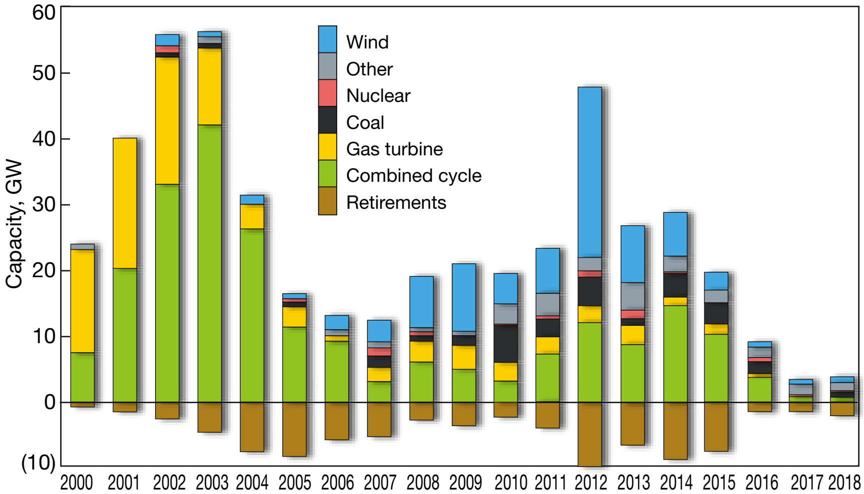
Robust mandates allow renewable technologies to capture a large portion of the power industry's relatively small incremental growth. With this sluggish short-term growth forecast, the only way for a fossil fuel to expand its generation share is at the expense of another fossil generating source. Fuel price economics and superior gas combined-cycle heat rates will expand gas base-load generation share at the expense of coal. EVA forecasts gas combined-cycle generation to reach 26% of total US power industry generation in 2018 (Fig 2).

From 2011 through 2018 over 70 GW of announced nameplate capacity additions are renewable technologies. However, because of high capital cost and tax credit uncertainty EVA estimates that only 52% of this announced capacity will reach commercialization. Prior to the American Recovery and Reinvestment Act renewable grants, renewable firms could apply for a tax credit to cover a portion of project costs. The stimulus package grant program expired at the end of 2011 and Congress has not yet extended it, so renewable developers must once again rely solely on the tax credit.

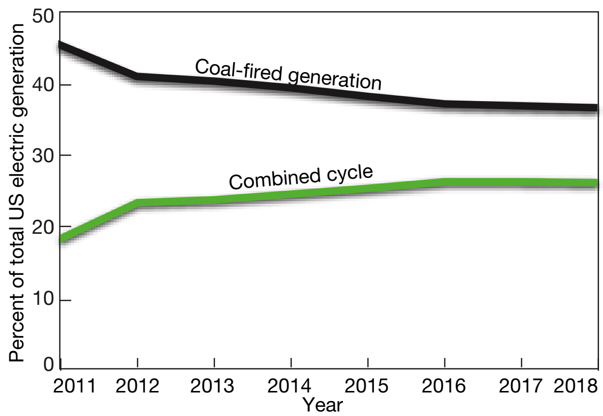
In addition, many renewable developers are small companies with relatively small tax bills who must rely on larger tax-equity partners to supply capital. Tax-equity partners are usually large financial institutions with larger tax bills who can take full advantage of these tax credits, then in turn finance renewable projects. The level of capital supply through tax-equity markets will determine the fate of many announced renewable projects. EVA believes this level of capital supply will be insufficient to maintain strong renewables growth.

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 17.3 GW of announced new coal capacity, EVA projects that only 9.3 GW will reach commercialization. From 2011 through 2018 announced coal retirements total 30.5 GW, resulting in a net loss of 21.2 GW of coal capacity.

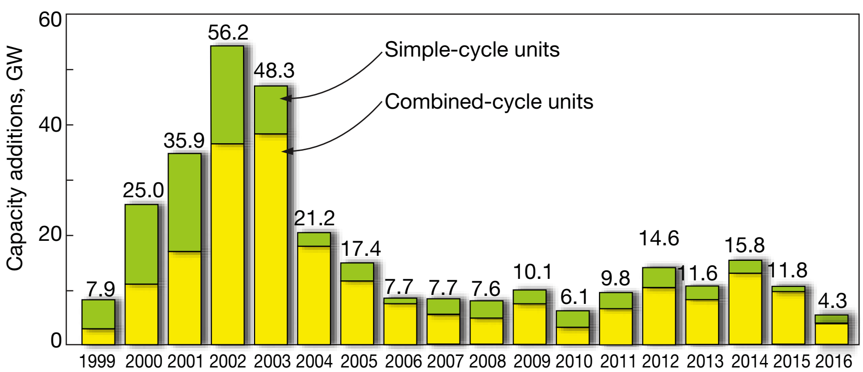
In addition to announced coal retirements, EVA forecasts an extra 27 GW will likely retire during this same period. EPA's CSAPR and MATS are the environmental regulations responsible for the majority of projected coal retirements. Gas combined-cycle units and a limited number of steam-plant conversions to gas will be the sources of replacement capacity.



1. Capacity additions announced for calendar years 2011-2018 total 163,128 MW. Natural gas announcements are 43% of the new capacity; wind, 32%; coal, 11%; nuclear, 4%; all other, 11%. 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 is represented by installed nameplate capacity while all others are summer capacity



2. Natural-gas-fueled combined-cycle generation is estimated to increase by 50.5% from 2011 levels and generate over 26% of US electricity in 2018. Coal generation will fall by 14.8%, leaving coal generating 36.8% of the nation's power, down from its 2011 market share of 45.4%



3. Bar graph of GT-based additions suggests that a min-boom is underway. New units are required to replace coal-fired retirements, cancelled coal plants, and to balance growing intermittent renewable generation. For the period evaluated, current announcements suggest that 83% 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

EVA projects coal generation to decline at a faster rate than coal retirements alone would indicate, resulting in a net decrease in fleet utilization. Displacement of coal-fired capacity by gas combined cycles and renewable growth mandates are responsible for coal's declining generation share. Fig 2 shows forecasted coal generation as a percent of total generation.

Coal-to-gas fuel switching increased in 2011 and displaced an estimated 140 TWh of coal generation with natural gas (from 2007-2008 generation levels). This is the equivalent of roughly 71 million tons of coal or 2.8 billion ft^3/day of gas.

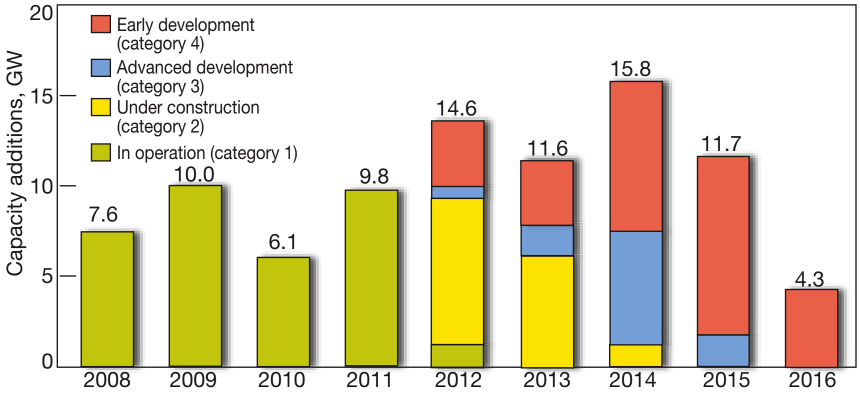
The mild winter of 2011-2012 has increased displacement even more because of excess gas supply throughout the nation. The additional gas supplies and storage withdrawals normally would have been used by the residential and commercial sectors for heating, but the mild temperatures significantly reduced demand. The combination of low gas prices and excess supplies is resulting in record levels of coal-to-gas fuel switching. Gas prices remaining below $3/million Btu in 2012 will ensure that a record amount of coal is displaced this year.

In addition to economic coal-to-gas displacement, utilities will displace coal units to comply with CSAPR in 2013. They may elect to environmentally dispatch combined-cycle units ahead of coal units because of tight CSAPR allowance markets and to retain banked allowances. In addition to economic displacement, EVA estimates that 31 to 42 TWh of environmental displacement could achieve full CSAPR compliance in 2013.

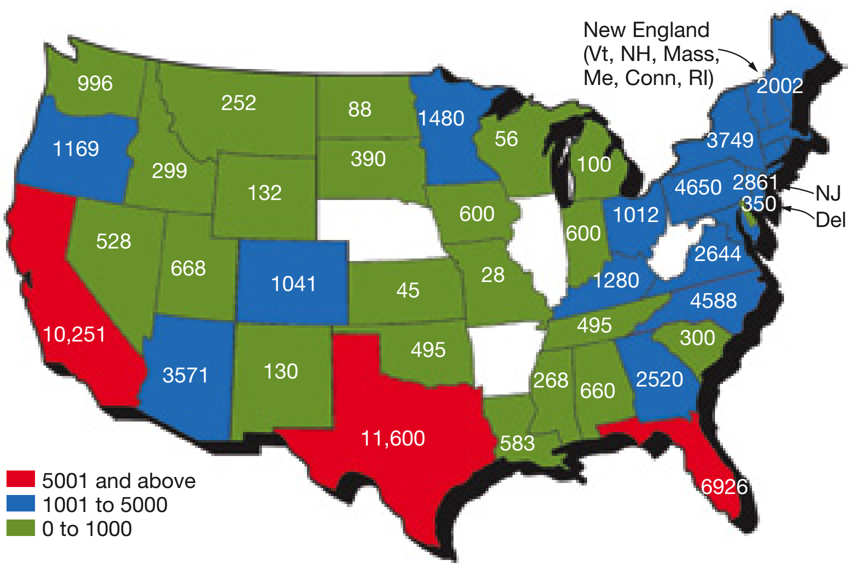
Fig 3 presents recent history and a look ahead for GT-based capacity additions. The illustration shows the spectacular growth of this industry sector in the 2000-2005 period, when more than 200 GW was installed.

A mini-boom is currently underway and over 50 GW is expected online from 2012 through 2015. Of the total 69.5 GW announced through 2018, 83% of capacity is combined-cycle technology, the remainder simple cycle. This ratio will likely decrease over time since peaking turbines are ordered much closer to their operation date. 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 45% of GT-based capacity from



4. Gas-turbine-based capacity by stage of development profiles 69.5 GW of announced capacity for the calendar years 2011 through 2018. Stagnant electricity demand will likely delay some projects and possibly force the cancellation of a few. Gas turbines are installed relatively quickly and 45% of the capacity is in the early development stage, making it relatively easy to tweak startup dates. Approximately 16% of the capacity is in an advanced stage of development, and another 23% is under construction. As of February 2012, an estimated 16% of announced capacity through the forecast period is already in operation



5. Looking at GT-based capacity additions by state from calendar years 2011 through 2018, states with the most announced new capacity are Texas (11,600 MW), California (10,251), and Florida (6926)

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.

2011-2018 is in the early development stage (Fig 4). These plants are the most vulnerable to changes in developers' plans. Another 16% of capacity is in advanced development, 23% is under construction, and 16% entered operation in 2011 or through February 2012. Over 41% of this announced new capacity is located in Texas, California, and Florida (Fig 5).

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

2. EVA's project tracking methodology

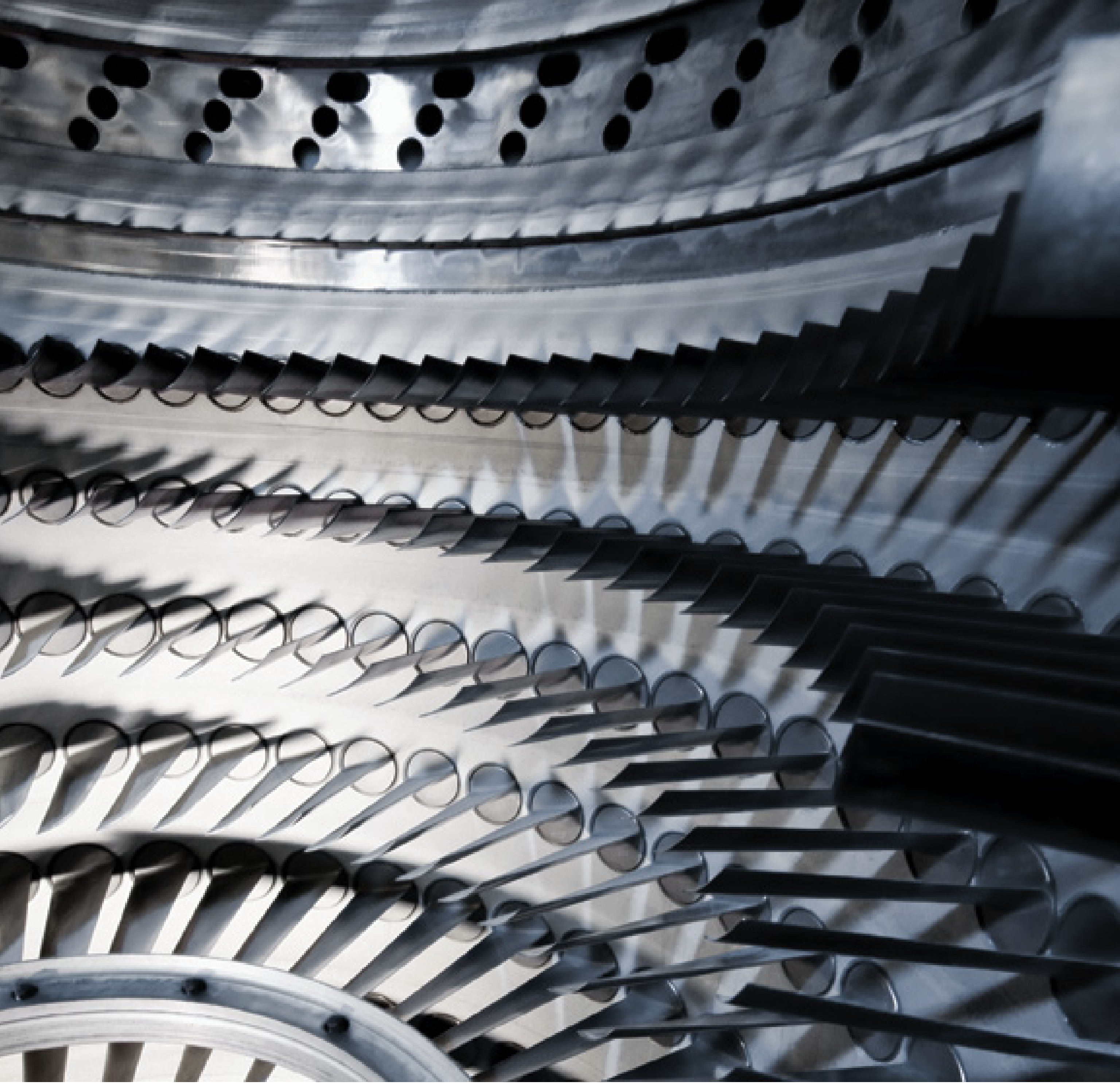
Today's mixed bag of regulation and deregulation make it far more difficult to access information on power-project development than in the regulated era. EVA has continually tracked announcements of changes to powerplant capacity since 1998. This includes new plants, retirements, uprates, and derates 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). EVA's seasonal methodology counts capacity in service by June 1 only; units added thereafter are attributed to the following year.

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.



Updating gas-turbine reliability, availability

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

Preparation by Strategic Power Systems Inc (SPS) for the **CCJ's** annual By the Numbers report normally begins with a careful look at ORAP® (Operational Reliability Analysis Program) performance metrics for aeroderivative (aero), "E" class, and "F" class technologies across all OEMs and a wide range of owner/operators. For 25 years, SPS's ORAP data have provided the opportunity to assess and understand trends in equipment duty and performance.

The table presents ORAP data for 2011, 2006 to 2010, and 2001 to 2005. The intent of using these three time periods is to highlight performance trends over significant periods of time—including the most current.

The reliability/availability/maintainability (RAM) metrics discussed below include service factor (the percentage of time a unit is generating power) and the ratio of service hours (the amount of time power was supplied to the grid) to starts. These numbers are indicative of the duty cycle or period of demand filled by the generating equipment.

Don't confuse service factor with capacity factor, which also appears in the table. The latter is the ratio of the power an engine produced in a given time period to that which it was capable of generating. Finally, availability and forced-outage factor show the impact of lost time and generation attributed to outages—both planned and forced.

Aero metrics

- The aeroderivative metrics show a decreasing service factor, period over period, since 2001-2005. In 2011, aeros operated 3539 annual service hours, a decrease of 192.8 hours when compared with 2006-2010, and a decrease of 332.9 hours when compared with 2001-2005.
- The service hours/start ratio decreased as well—from 37.1 hours/start for 2001-2005 to 34.2 in 2011. Annual starts were relatively constant for 2011 when compared with 2001-2005 (104 annual starts). However, 2011 starts were substantially lower when compared with 2006-2010 (average of 117 annual starts).
- Capacity factor shows a continual decrease, period over period, since 2001-2005. This indicates a reduced level of power output.
- Availability continually decreased, period over period. Annual outage hours increased from 516.8 hours in 2001-2005 to 657 in 2006-2010 to 788.4 in 2011. Annual forced-outage hours and maintenance outage hours increased, period over period.
- Forced-outage hours represented 45.6% of all outage time in 2011 compared with 44% in 2006-2010 and 39% in 2001-2005.

Data in this report are SPS ORAP Verified

"E" class metrics

- The "E" class metrics show an increasing service factor, period over period, since 2005. In 2011, "E" class units operated 3434 hours, an increase of 192.7 hours when compared with 2006-2010 and an increase of 254 hours when compared with 2001-2005.
- The service hours/start ratio increased from 42.4 hours/start in 2001-2005 to 56.0 in 2011. Annual starts decreased, period over period, from 75 in 2001-2005 to 68 in 2006-2010 to 63 in 2011.
- Capacity factor increased, period over period, since 2001-2005. This indicates an increased level of power output.
- Availability decreased slightly, period over period. Unavailability went from 5.3% in 2001-2005 to 5.5% in 2006-2010 to 6.0% in 2011. Unavailability was driven by an increase in maintenance outage hours, period over period.
- Forced-outage hours represented 19% of all outage time in 2011 compared with 23.6% in 2006-2010 and 20.8% in 2001-2005.

ORAP RAM metrics: Historical perspective

	2011	2006-2010	2001-2005
Aeroderivative			
Service factor, %	40.3	42.6	44.2
Service hours per start	34.2	32.0	37.1
Capacity factor, %	30.5	33.5	36.0
Availability, %	90.7	92.5	94.1
Forced outage factor, %	4.1	3.3	2.3
"E" class			
Service factor, %	39.3	37.0	36.3
Service hours per start	56.0	47.9	42.4
Capacity factor, %	37.2	35.0	34.1
Availability, %	94.0	94.5	94.7
Forced outage factor, %	1.1	1.3	1.1
"F" class			
Service factor, %	55.1	53.9	55.2
Service hours per start	68.3	53.7	47.5
Capacity factor, %	49.0	47.2	50.1
Availability, %	91.4	93.0	92.6
Forced outage factor, %	2.6	1.7	2.0

"F" class metrics

- The "F" class metrics show the highest level of service factor when compared with both aero and "E" class units, period over period. In 2011, "F" class units operated 4853 hours in 2011, compared with 4721.6 in 2006-2010 and 4835.5 in 2001-2005.
- The service hours/start ratio increased, period over period, from 47.5 hours/start in 2001-2005 to 53.7 in 2006-2010 to 68.3 in 2011. Annual starts decreased from a high of a 102 in 2001-2005 to 72 in 2011. The nominal 30% decrease in annual starts in the last 11 years reduces the

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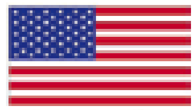

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Based on this real-life experience, more plant maintenance supervisors and planners are choosing to replace original lower-quality, foreign-made valves with new Conval Camseal ball valves, Swivldisc gate valves and Clampseal globe valves.

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Long-term view

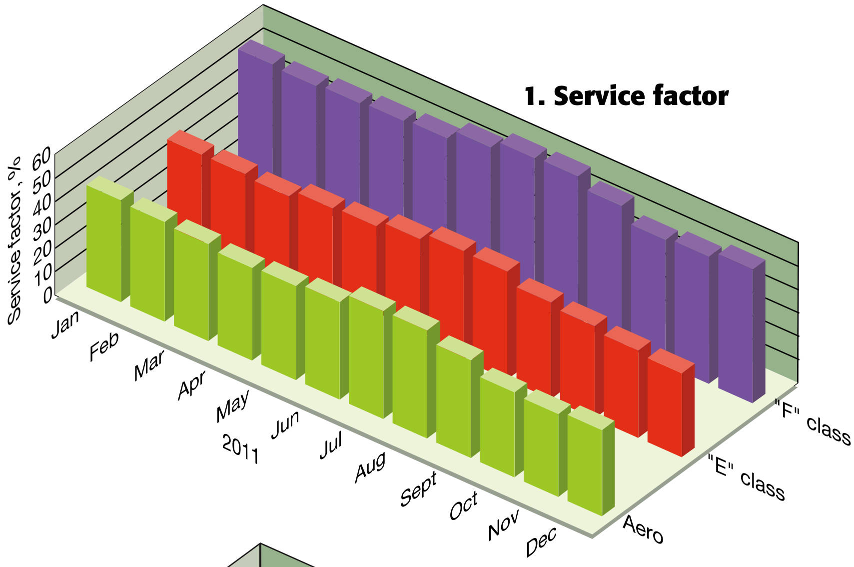
Black & Veatch, Kansas City, made some bold predictions in its December 2011 *Energy Strategies Report* regarding how the energy mix for power generation in 2036 would compare with that for 2012.

Over the next 25 years, the company expects the share of electric power generated from natural gas in the US to increase from 24% to 44% while coal drops from 41% to 16%. Renewables' share of electric power production would increase from 6% to 13% over the same period.

Robert Patrylak, managing director of B&V's Energy Market Perspective (EMP) service, was quoted in the article as saying that up to 61,500 MW (approximately 20% of today's coal fleet) could be retired by 2020. This is in close agreement with the EVA data presented in the first article for this special section.

The EMP forecast predicts renewable generating capacity to more than triple over the 25-yr period, mostly from wind resources.

Generation mix	Production, % of kWh generated 2012	Production, % of kWh generated 2036
Natural gas	24	44
Coal	41	16
Renewables	6	13
Nuclear	20	19
Hydro	9	8



1. Service factor

2. Service hours per start

adverse impacts of cyclic duty for these "F" class units.

- Capacity factor was higher than it was for the aero and "E" class units.
- Availability was relatively consistent, period over period, with 2011 showing the lowest level of any reporting period. In 2011, "F" class units were unavailable 8.6% of the time, or 753.4 outage hours. This was an increase of 140 outage hours when compared with 2006-2010 and an increase of 105 hours when compared with 2001-2005.
- Forced-outage hours represented 30.2% of all outage time in 2011, compared with 24.3% in 2006-2010 and 27% in 2001-2005.

End notes

The illustrations show 2011 ORAP data on a monthly basis. Note from Fig 1 that there is little variability in service factor in each of the three technology classes. This indicates that service hours and starts are relatively uniform on a monthly basis by engine class. No significant summer or winter peak is evident from the metrics.

Interestingly, however, both "E" and "F" class units have higher service hours per start ratios in both the first and last three months of 2011 (Fig 2). Perhaps this reflects the need for longer run cycles without increasing monthly service hours. The service hours per start ratio for aeros is relatively consistent month-to-month. CCJ

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Axford: 2011GT orders better than predicted, 2012 better still

Stealing a line from an old brokerage ad, when Mark Axford talks, everyone listens. That certainly was true at Western Turbine XXII, where the Houston-based turbine consultant one again attracted a larger audience than any other speaker. It's not easy to fill a cavernous ballroom in the Pasadena Convention Center at 8 a.m. following an evening of celebration but Axford did because of the respect he has earned among aero owner/operators over the years.

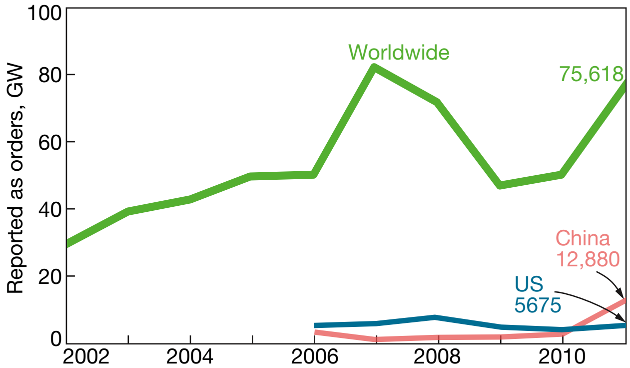
Axford's delivery was impeccable. He began his well-prepared remarks almost apologetically for greatly underestimating last year's orders. At the previous meeting of the Western Turbine Users Inc (WTUI) in March 2010, Axford predicted that US orders would be up 25% in 2011 versus 2010, worldwide orders up 15%.

US orders actually were up 31%, pretty much on target. But global orders were up 54% (to 75,618 MW), producing the second largest year-over-year increase in gas-turbine orders worldwide ever (Fig 1). "If orders from China had been up only 10% instead of 315%, then the forecasted global orders would have been up about 34%, similar to the US," Axford said.

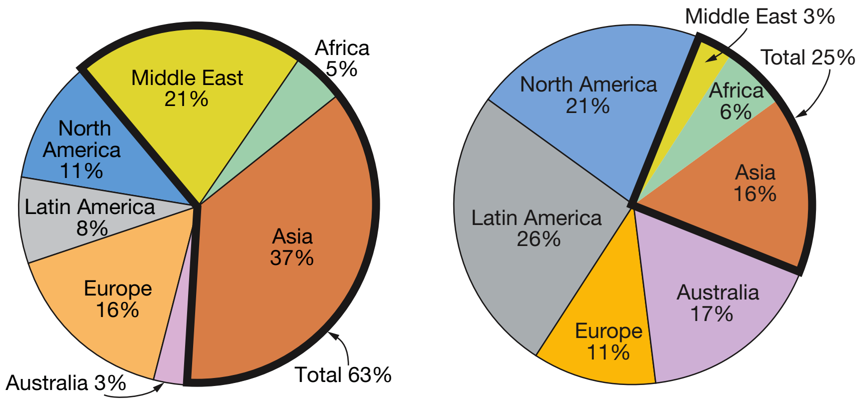
In the US, orders for gas turbines larger than 10 MW totaled 5675 MW, 39% for simple-cycle service. Orders were stimulated primarily by the reassessment of nuclear safety, the low cost of natural gas, closures of coal-fired plants, and positive economic news in some regions.

Overseas, the bulge in orders was attributed to the closing of nuclear plants in Japan and Germany because of the Fukushima disaster, new gas finds, air pollution concerns, and unexpected growth in emerging markets—such as China (12,880 MW). Figs 2 and 3 show that nearly two-thirds of the gas turbine capacity ordered in 2011 will be installed in the Middle East, Africa, and Asia; 13% of the new capacity will be produced by aero engines.

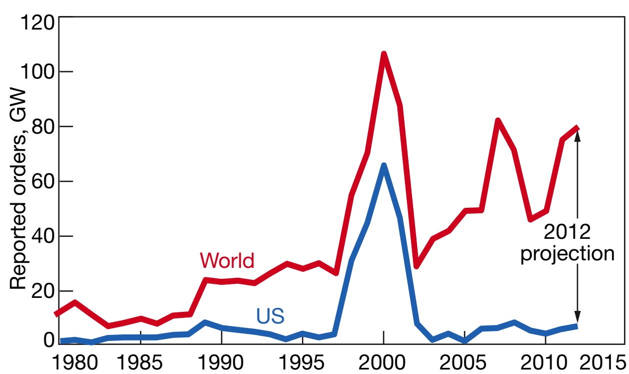
Next, Axford analyzed worldwide orders by OEM. In the five-year period, 2007-2011, he said GE and Siemens together captured between 73% and 82% of the market—the highest percentages coming in years with the fewest orders. Each year, GE was slightly more successful than Siemens. In 2011, the consultant said GE had 40% of the market, Siemens 36%. Rounding out the 2011 stats, Mitsubishi garnered about 12% of the orders, Alstom just shy of 5% , and everyone else slightly more than 7%.



1. Worldwide orders of gas turbines larger than 10 MW totaled 75,618 in 2011. China ordered more than twice the capacity that the US did (12,880 MW versus 5675). Turbine Consultant Mark Axford noted that in 1985, US orders were one-quarter of the worldwide total, today they're less than 8%. In China, gas turbine capacity was up 315% over 2010; 95% of the total is combined cycle



2, 3. More than 60% of the gas-turbine capacity ordered in 2011 will be installed in the Middle East, Asia, and Africa (left). Orders of aero engines in 2011 was up 44% from a year earlier and totaled 9902 MW (right)



4. The big picture and history of gas turbine orders reveals three booms worldwide, one in the US

In the competition between frames and aeros, heavy frame turbines have captured between 84% and 87% of the global market since 2007—87% in 2011. Aeros are the clear choice among users for gas turbines rated between 18 and 65 MW, which includes all the LM engines supported by WTUI. Global orders for LM6000s totaled 44 engines in 2011, with the "big deal" being a dozen units going to an Australian LNG project. Axford said that was only the second time the LM6000 has been ordered for mechanical-drive purposes.

Last year, aeros were preferred over frames in the 18-to-65-MW range by nearly 2:1. Interestingly, Fig 3 shows that Asia, Africa, and the Middle East purchased only 25% of the 9902 MW of aeros sold in 2011, while buying 63% of all the gas turbines ordered worldwide.

Looking at the North American market separately, Axford told the group that 2011 frame orders in the region totaled 6124 MW, with GE capturing 40% of that capacity and Siemens 39%. Mitsubishi had 13% of the market on the sale of three 501Gs, Alstom 3% on the sale of one GT24. Aero orders in North America came to 2095 MW with GE getting a whopping 80% of the market, Pratt & Whitney 14%, and Rolls Royce the balance.

Axford's forecast for 2012, the nutshell version: Orders of gas turbines larger than 10 MW up 20% (megawatt basis) in the US, up 5% worldwide. In round numbers, Axford sees 80,000 MW being ordered globally this year. Here's some of the thinking that went into the projections:

- Europe. In recession, electric demand is soft; orders for gas turbines will slow.
- US. Mild economic recovery and low natural gas prices with coal under pressure combine for an optimistic outlook for gas turbine orders.
- Asia. Torrid order rate for gas turbines, which Axford said is not sustainable without major new supplies of natural gas. In Japan, 53 of the country's 54 nuclear reactors—approximately 50,000 MW—are idled for safety reviews and other considerations. In the near term, more LNG will be required by Japan; in the longer term, perhaps significant new GT capacity.

Finally, Axford noted that the US is "awash in natural gas," a market dislocation that is expected to promote exports of LNG (reversing the import terminals), maximize electricity production with that fuel (now at $2.30/million Btu compared to coal at about $3), and promote the use of natural gas in vehicles. CCJ

Gas below $5 until 2016

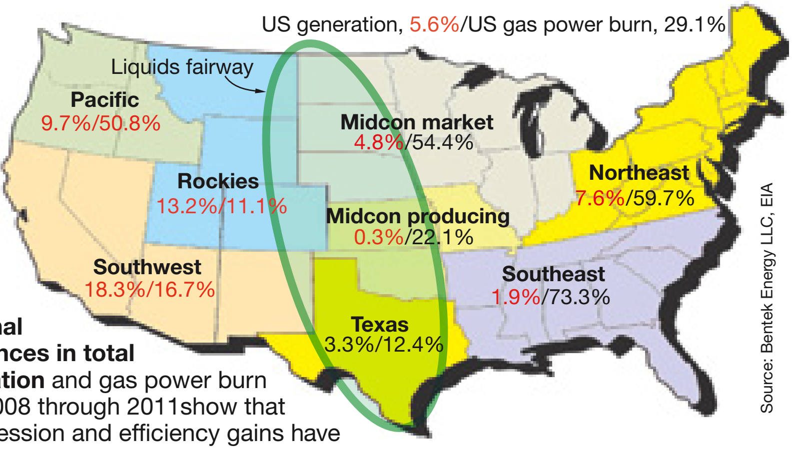
"Natural gas market fundamentals and forecasting," the first broadcast (mid March) in the *Current Intelligence* webinar series sponsored by GDF Suez Energy Resources NA, proved valuable to generation professionals as well as to commercial, industrial, and institutional electricity buyers. Access the webinar series at http://gdfsuezenergyresources.com.

Robinson

The featured speaker, Jennifer Robinson, a senior energy analyst at Bentek Energy LLC, Evergreen, Colo, treated the cyber audience of over 400 to a wealth of information on domestic production and explanations of both supply- and demand-side metrics affecting the price of natural gas (natgas). Robinson is responsible for Bentek's *Northeast Observer* and *NE Market Call* publications.

Highlights of the presentation:

- Significant drilling in the center of the country is driving supply growth, which continues to outpace increasing demand—at least for now. Producers in the so-called "Liquids fairway" (area of the map defined by the green line) have added rigs at a blistering pace to extract high-value natgas liquids and condensates from shale formations. Rig count in the Eagle Ford, Permian, Anadarko, and Williston fields alone increased by 245 in the past year.
- Storage inventories are headed for all-time highs because of increased production and a mild winter. If this summer is mild as well, there is the potential for supply to "bump up against constraints and test [storage] capacity" in the shoulder months. If this happens, Robinson warned, downward pressure on prices would be "severe" and gas prices could drop below $2 by October.
- According to Bentek, low prices are fueling strong demand growth in the near term. Market indicators include increasing electric production by natgas-fired powerplants, an uptick in orders for gas-turbine-powered generating stations (see previous article), and the retirement of coal-fired units east of the Mississippi River.
- Fuel switching: In the long term, infrastructure changes in the Northeast to replace fuel oil with natural gas for heating also will buoy demand.
- Total generation is down in the US by 5.6% since 2008, while the gas power burn has increased by 29.1% (map). From a regional perspective, displacing coal power in the Northeast and Southeast has led to tremendous gains in market share for gas-fired generation.
- What will the future bring? Gas prices will most certainly rise. The Cross-State Air Pollution Rule will make it uneconomical for coal-fired plants to operate in some areas. Several LNG terminals, originally slated for import, will be converted for export service and cut into domestic supply. All this leads to the addition and increased use of gas-fired plants, especially in renewables-stricken areas east of the Mississippi River. Bentek Energy estimates that supply and demand will gradually converge, with gas prices hitting the $5 mark sometime in 2016. CCJ



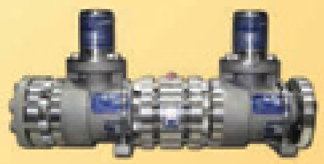
Regional differences in total generation and gas power burn from 2008 through 2011show that the recession and efficiency gains have taken a bite out of total generation in all markets except Texas and that coal displacement by gas is a dominant market indicator east of the Mississippi River

THE YF ELECTRIC FAMILY

BASIC SHUTOFF

The Y&F 9200 Series Isolation Valve

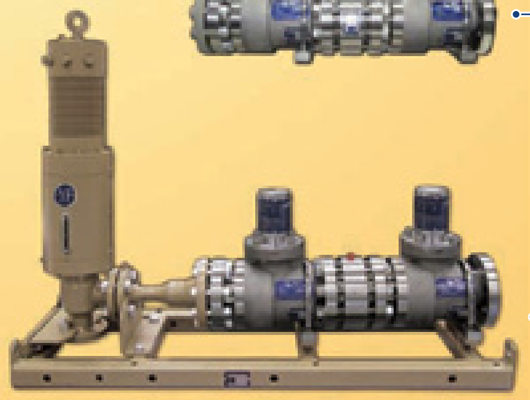
This solenoid operated, pilot controlled isolation valve meets the requirements for a fast acting, high temperature shutoff valve for use on GE Energy, Pratt & Whitney and Rolls-Royce turbine engines.



REDUNDANT SHUTOFF

The 9200D490-G001 Series Isolation Valve in Double Block & Bleed Format

Comprised of two 9200's, this valve is used to rapidly shut off gas fuel flow upstream of the primary gas control valve(s) in the event of a turbine trip condition. The valve then isolates the fuel source from the turbine engine.



COMPLETE RAIL

The Y&F 8609 Series Gas Fuel Rail

THE standard used for pipelines.

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The Y&F Frame 5002E Fuel Skid

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Best Practices Awards


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GTAA Cogen


McClain


Tenaska Virginia

One of the biggest challenges facing owners and operators of gas-turbine-based powerplants 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 COMBINED CYCLE Journal has as its primary objective the recognition of the valuable contributions made by plant staffs—and headquarters engineering and asset-management personnel as well—to improve the performance of GT-based generating facilities. Entries for the 2012 awards in Operation and Maintenance (two categories this year: Balance of Plant, Business), Design, Environmental Stewardship, and Safety (two categories: Procedures & Administration, Equipment & Systems) are presented in the more than two-dozen pages that comprise this report—all edited for style, some for length. A quick read is sure to uncover an idea or two that can be repurposed at your plant to increase reliability/availability, boost efficiency, reduce air and water emissions, and/or improve safety.

The entries were judged by seven members of the CTOTF Leadership Committee, chaired by Bob Kirn of the Tennessee Valley Authority. The Combustion Turbine Operations Technical Forum, the nation's oldest GT user group, and the one with the broadest coverage in terms of manufacturers and models served, will host the presentation of awards during the organization's Spring Turbine Forum at the Williamsburg Lodge in Williamsburg, Va, April 16.

There are two levels of awards to recognize the achievements at individual plants: Best Practices and The Best of the Best, as determined by the judges. Award recipients will be announced in the next issue.

Please judge the entries on your own, using the guidelines and scorecard presented at the end of this report. E-mail Senior Editor Scott Schwieger (scott@ccj-online.com) with your choices in each category and tell him why you selected the plants you did. We welcome your input and will include it in the next issue along with the judges' results.

Announcement of the 2013 awards program is made elsewhere in this issue. Alternatively, you can get details at www.ccj-online.com/best-practices. Entries should not take more than a couple of hours to prepare and can be submitted to Schwieger at any time on or before Dec 31, 2012. This is one way to get the recognition your plant, your staff, and you have earned by your collective resourcefulness. Please plan to participate.


Higgins

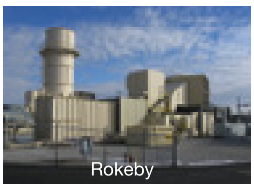

Faribault Energy Park


Ceredo


Ospray


Hopewell Cogen


River Road


Rokeby


Termoemcali


Central Alabama


Wharton

Contents

20 Safety Procedures & Administration
42 Safety Equipment & Systems
56 Environmental Stewardship
66 O&M Balance of Plant
76 O&M Business
82 Design
85 How entries were judged
86 You be the judge
87 Sponsors of the awards program

Achieving elevated safety awareness standards through an employee-developed hazard recognition course

T H Wharton Generating Station

NRG Energy

Challenge. "Safety First" is virtually every organization's *given* top priority and goal. NRG Energy and T H Wharton employees share this top priority. However, maintaining a constant, high level of safety awareness is challenging as focus often diminishes over time, regardless of the numerous safety programs employed.

The trends of T H Wharton safety audits and inspections highlighted several issues that were continually being identified. One example was labeling of secondary containers. Audit teams found that employees transferring chemicals into a secondary container were either attaching incorrect information to the container or not attaching proper identification at all.

In order to correct this issue and improve employee awareness, Roger W McConnell, plant manager, suggested increasing employee engagement in safety by having multiple examples of both correctly and incorrectly labeled containers and having a competition where employees would identify the errors. This worked very well both in substantially decreasing incorrectly labeled containers and winning positive feedback from employees.

Success in hand, McConnell suggested the creation of a larger employee safety immersion project where groups of employees could walk through process a hazard recognition course and identify staged safety issues.

Solution. This OSHA VPP Star site upped the ante on safety by challenging its employees to develop a program to increase safety awareness through hazard recognition. Acknowledging that safety starts with employee involvement and a good hazard recognition foundation, the TH Wharton plant manager and the site safety coordinator led a core leadership team to design a hazard recognition course and competitive program at the plant's retired Unit 2.

Designating the course, "Hogan's Alley," the subcommittee populated it with the issues identified by safety audits and inspection findings. The intent was to create an area that personnel could walk safely through and view hazards while not being directly exposed to any of the dangers it illustrated.

The hazard recognition course is staged with hazards throughout the unit, from the basement to the control room and turbine deck (photos). Employees traverse the course and identify the hazards along the way. At the end of the course, employees review the hazards key and are graded on their level of hazard recognition. Top finishers win a lunch date with the plant manager.

Originally we had 79 separate hazards, but by the end of the initial testing, employees had identified 89 additional items that were not included in the original hazard list. With the new hazards identified we were ready to have all plant personnel compete.

Results. This "out-of-the-box," uncon-

T H Wharton Generating Station

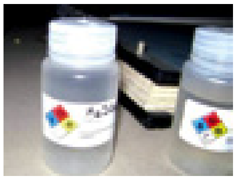
1025-MW, gas-fired, combined-cycle and peaking facility located in Houston, Tex

Plant manager: Roger W McConnell

Key project participants:
- Billy Merritt, I&C technician (Site VPP coordinator)
- Raymond Taylor, electrician
- Zachry Loessin, mechanic
- Jimmy Bryant, supervisor
- David Reyna, supervisor
- NRG Energy safety professionals and coordinators

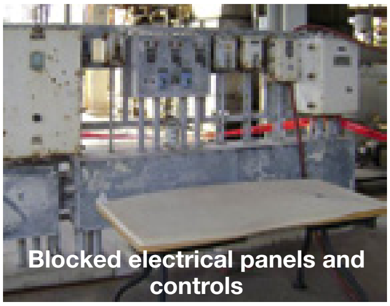
Real-life hazard recognition at T H Wharton


No pre-use inspection sheet


Mislabled chemical

Damaged signage


Valves locked without any information provided


Blocked electrical panels and controls


Meet Hogan! Lanyard tied off to handrail, not wearing fall protection, using a cheater bar, no safety toe shoes, pipe wrench handle bent


Good housekeeping: Improperly stored equipment


Nuts stacked on lip of water box


Valve wrench improperly stored


Damaged flexible conduit with exposed wiring

ventional, and non-classroom training program increases employee involvement, sharpens hazard recognition acumen, provides the foundation for other plant safety programs, and helps maintain the plant's excellent safety standards and targets. Hogan's Alley and its success have been shared and adopted throughout the company.

Other regional plants have sent teams to the site, and some have developed their own hazard recognition courses. Our employees are now more proactive and the quality of safety concerns has seen a marked improvement. Employees also come away from the training with a greater understanding of hazards.

Currently, T H Wharton and its sister plant are sending employees proficient in hazard recognition to a cross-town plant's new course for a friendly "Top Gun" competition. Additionally, Hogan's Alley has also been shared and recognized at OSHA VPP conferences.

Personnel at T H Wharton encourage employees at other plants to set up a program like this at your facility. You don't need an abandoned unit to accomplish this process. Any open area, or even a conference room, can be barricaded off to fashion a course.

Finally, if you decide to institute a Hogan's Alley, please ensure your employees are properly protected from the hazards you put in place. This small step is of the utmost importance.

Computerized emergency action plan expedites response

Hopewell Cogeneration Facility

IPR-GDF Suez Energy North America

Challenge. Most plants have a large binder with all the required action plans and procedures. The volume of this binder is a safety hazard in itself. Most plants have tabs to find the correct procedure, but seasoned operators have these emergencies memorized. This is a good practice, but the follow-up action is sometimes delayed because the operator is looking up the procedure to be sure he/she has not forgotten any steps.

Solution. One thing that can help is having the procedures for emergencies in a Microsoft® Access database or Excel spreadsheet. Both of these methods work very well to expedite response to an emergency. Placing an icon on all computers throughout the plant adds an extra level of preparedness. A simple click on the icon brings up the screen with a list of emergencies (Fig 1).

Results. Illustrating an example of an oil leak on the steam turbine that catches fire shows the program's effectiveness (Fig 2). As engineers, we want lubricating oil to flow in case of a pump failure and normally there is a battery powered backup pump in case of loss of electrical power. In this case, however,

Hopewell Cogeneration Facility

365-MW, gas-fired, 3 × 1 combined-cycle cogeneration facility located in Hopewell, Va

Plant manager: Bob Greene

Key project participants:
Chuck Barnes, plant engineer
Entire Hopewell staff

the lube oil is feeding the fire and it needs to be turned off. The procedure indicates what has to be done and a button also links to a list of breakers and their locations to take the lube-oil pumps offline.

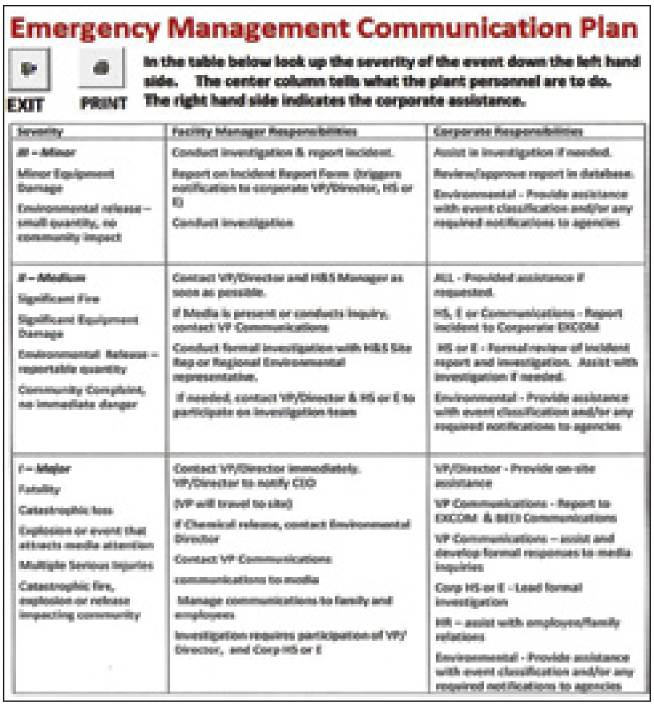
Another area in the database lists whom to contact depending on the severity of the event (Fig 3). The communications plan tells whom to contact under what conditions, and a task force that has just been formed to handle news media and help with state and federal offices.

Another important feature of the system locates sensitive areas, such

Emergency Information

- Ammonia Leak
- Black-out of the Plant
- Bomb Threat
- Civil Disturbance (Protestors, Pickets, etc.)
- Cold Weather
- Communications Plan
- Complaint or Request for Information
- Earthquake
- Emergency Action and Evacuation Plan
- Emergency Phone Numbers
- Fire
- Flooding
- Gas Leak from another plant
- High Winds
- Insurance Phone # if Fire System is Out
- Lube Oil Fire on Gas Turbine
- Lube Oil Fire on Steam Turbine
- Natural Gas Leak
- Notify OSHA of death, 3 or more Hospitalized
- Oil or Chemical Spill
- OSHA Inspection unannounced
- Rail or Tractor Trailer Incident
- Security Incidents (Break-in, etc.)
- Sensitive Areas and Hazardous Chemical List
- Spill Calculator (Who to Call)
- EXIT

1. Instructions on how to handle emergencies are only a mouse-click away

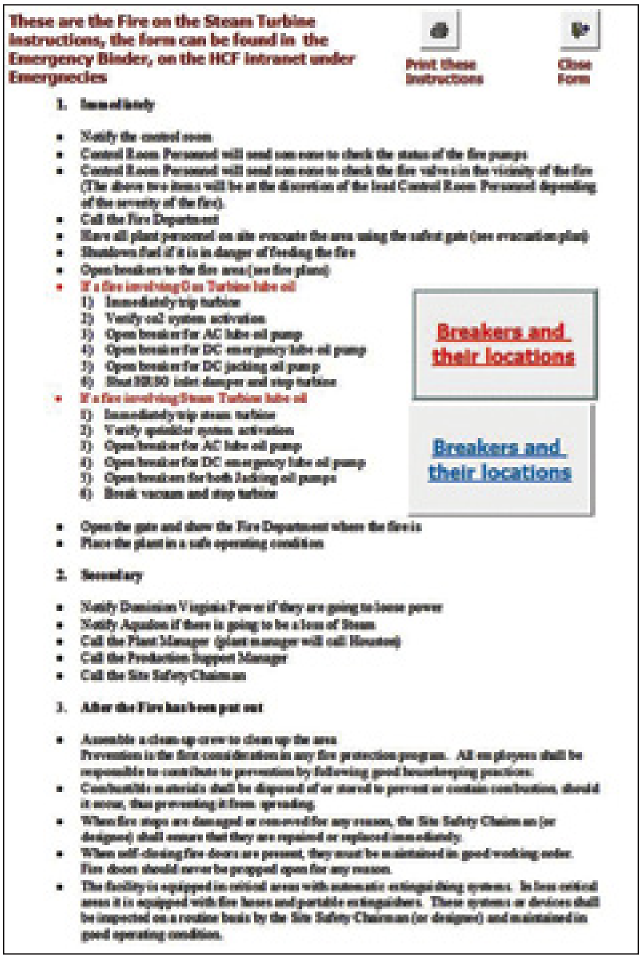


Emergency Management Communication Plan

EXIT PRINT

In the table below look up the severity of the event down the left hand side. The center column tells what the plant personnel are to do. The right hand side indicates the corporate assistance.

Severity	Facility Manager Responsibilities	Corporate Responsibilities
III – Minor Minor Equipment Damage Environmental release – small quantity, no community impact	Conduct investigation & report incident. Report on Incident Report Form (triggers notification to corporate VP/Director, HS or E) Conduct investigation	Assist in investigation if needed. Review/approve report in database. Environmental - Provide assistance with event classification and/or any required notifications to agencies
II – Medium Significant Fire Significant Equipment Damage Environmental Release – reportable quantity Community Complaint, no immediate danger	Contact VP/Director and H&S Manager as soon as possible. If Media is present or conducts inquiry, contact VP Communications Conduct formal investigation with H&S Site Rep or Regional Environmental representative. If needed, contact VP/Director & HS or E to participate on investigation team	ALL - Provided assistance if requested. HS, E or Communications - Report incident to Corporate EXCOM HS or E - Formal review of incident report and investigation. Assist with investigation if needed. Environmental - Provide assistance with event classification and/or any required notifications to agencies
I – Major Fatality Catastrophic loss Explosion or event that attracts media attention Multiple Serious Injuries Catastrophic fire, explosion or release impacting community	Contact VP/Director immediately. VP/Director to notify CEO (VP will travel to site) If Chemical release, contact Environmental Director Contact VP Communications communications to media Manage communications to family and employees Investigation requires participation of VP/Director, and Corp HS or E	VP/Director - Provide on-site assistance VP Communications - Report to EXCOM & BEI Communications VP Communications – assist and develop formal responses to media inquiries Corp HS or E - Lead formal investigation HR – assist with employee/family relations Environmental - Provide assistance with event classification and/or any required notifications to agencies



These are the Fire on the Steam Turbine instructions, the form can be found in the Emergency Binder, on the HCF intranet under Emergencies

Print these Instructions

Close Form

1. Immediately

- Notify the control room
- Control Room Personnel will send someone to check the status of the fire pumps
- Control Room Personnel will send someone to check the fire valves in the vicinity of the fire (The above two items will be at the discretion of the lead Control Room Personnel depending of the severity of the fire).
- Call the Fire Department
- Have all plant personnel on site evacuate the area using the safest gate (see evacuation plan)
- Shutdown fuel if it is in danger of feeding the fire
- Open breakers to the fire area (see fire plans)
- If a fire involving Gas Turbine lube oil
  1) Immediately trip turbine
  2) Verify co2 system activation
  3) Open breaker for AC lube oil pump
  4) Open breaker for DC emergency lube oil pump
  5) Open breaker for DC jacking oil pump
  6) Shut HRSG inlet damper and stop turbine
- If a fire involving Steam Turbine lube oil
  1) Immediately trip steam turbine
  2) Verify sprinkler system activation
  3) Open breaker for AC lube oil pump
  4) Open breaker for DC emergency lube oil pump
  5) Open breakers for both Jacking oil pumps
  6) Break vacuum and stop turbine
- Open the gate and show the Fire Department where the fire is
- Place the plant in a safe operating condition

Breakers and their locations

Breakers and their locations

2. Secondary

- Notify Dominion Virginia Power if they are going to loose power
- Notify Aqualon if there is going to be a loss of Steam
- Call the Plant Manager (plant manager will call Houston)
- Call the Production Support Manager
- Call the Site Safety Chairman

3. After the Fire has been put out

- Assemble a clean-up crew to clean up the area
  Prevention is the first consideration in any fire protection program. All employees shall be responsible to contribute to prevention by following good housekeeping practices.
- Combustible materials shall be disposed of or stored to prevent or contain combustion, should it occur, thus preventing it from spreading.
- When fire stops are damaged or removed for any reason, the Site Safety Chairman (or designee) shall ensure that they are repaired or replaced immediately.
- When self-closing fire doors are present, they must be maintained in good working order. Fire doors should never be propped open for any reason.
- The facility is equipped in critical areas with automatic extinguishing systems. In less critical areas it is equipped with fire hoses and portable extinguishers. These systems or devices shall be inspected on a routine basis by the Site Safety Chairman (or designee) and maintained in good operating condition.

2. Example: Instructions on what to do if oil leaks from a turbine and catches fire (above)

3. Emergency management communication plan provides clear, concise instructions (left)

4. Sensitive areas onsite and locations of hazardous chemicals are easy to find

as the onsite habitats for bald eagles (Fig 4). Also, from any plant computer, a list of hazardous chemicals, unannounced OSHA inspection checklists, and a spill calculator can be accessed to find out if a spill has to be reported.

Safety permit stations streamline maintenance

Granite Ridge Energy

Owned by Granite Ridge Energy LLC
Operated by NAES Corp

Challenge. Our plant issues multiple safety permits for safe work, confined space, and hot work to contractors and employees during routine maintenance and major outages which must be maintained at the work location. These permits identify hazards and controls for each job so that all workers are informed and work is done safely.

Permits must remain visible and as close to the work area as possible. In the past, permits have been difficult to locate and sometimes end up in tool boxes, on top of equipment, taped to a wall, or thrown in the trash. These practices have impeded work efficiency while workers hunt for either current permits or look for expired permits at the end of the shift.

Solution. Operator-designed and -implemented safety permit stations are strategically placed at each piece of major equipment so that permits can be prominently displayed. Some stations are permanent while others will be used only for outage events. Each station is boldly colored and accommodates all of the required safety permits (Fig 5). Confined space permits are attached to a clip board for easy sign in and sign out.

Results. The installation of the safety permit stations in fixed designated areas has not only raised awareness of the work hazards and controls but has increased the efficiency of issuing and collecting safety permits. Contractors know where to find permits for daily safety briefings and know where to return permits that have been removed for verification. For plant employees, it allows expeditious retrieval of expired permits at shift change and quick renewal so that work continues with minimal interruption. In addition, inspection of permits by safety officers and supervisors is more efficient.

5. Safety permit stations are strategically located and very visible

Granite Ridge Energy

730-MW, gas-fired, two-unit, 1 × 1 combined cycle located in Londonderry, NH

Plant manager: William Vogel

Key project participants: Robert Kirby, power block operator

Outage safety procedures eliminate tripping hazards

Walter M Higgins Generating Station

NV Energy

Challenge. In past outages, while working in and around the turbine enclosures, several near-misses occurred. Cords, air lines, and welding cables caused tripping hazards when personnel entered and exited the enclosures. Fortunately, nobody has been injured, but as we all know, near-misses will eventually add up to a lost-time incident.

Solution. During a Lessons Learned session after one such outage, the issue of tripping hazards was brought up. Several ideas were kicked around, but many of them were not doable because of fire systems codes and other safety-related reasons.

The final solution was brought up and thought out by our lead plant mechanic, Dave Cairns. His idea was to place penetrations on the enclosures in several places to facilitate lines, cords, and leads (Figs 6-8). While not in use, 'blind flanges' would block or seal the opening inside and outside the enclosures.

Another idea was brought up and discussed by plant personnel that having another source for 110-V plug-ins near the units would help alleviate these issues as well. In the past, portable power stations were set up and all extension cords ran from them. This resulted in numerous electrical cords lying around crossing long distances to reach areas where they were needed.

An area behind the electrical package for the generator was decided to be the best place to locate some plug-ins. Four 110-V ac plugs as well as two 100-amp and two 60-amp, 480-V 3-phase switch/plugs were installed on both units (Fig 9).

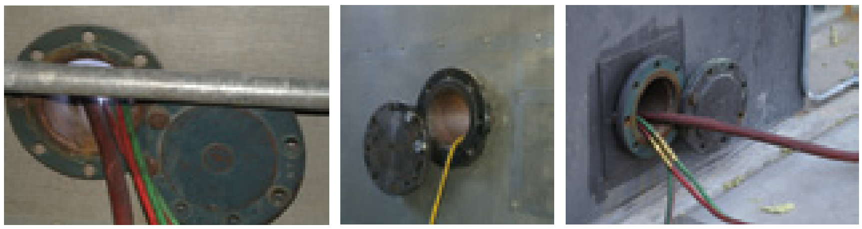
Results. These changes resulted in shorter electrical cord runs while working on and around the equipment and help keep walkways and paths clear of tripping hazards as well. Outage work at any time can be full of hazards and near misses. In working to avoid

Walter M Higgins Generating Station

530-MW, gas-fired, 2 × 1 combined cycle located in Primm, Nev

Plant regional director: Tom Price

Key project participants:
David Cairns, lead plant mechanic
Entire Higgins staff



6-8. Penetrations on enclosures eliminate the need to run lines, cords, and leads through doorways

9. Plug-ins eliminate need for portable power stations

incidents and the potential of lost-time accidents, everyone needs to be aware and to be thinking of better and safer ways to do things. At our plant, that is part of the work ethic that each plant employee displays daily.

Installation was completed in 2010 and the 2011 spring outage proved how well this idea worked. The outage was completed without a single near-miss involving tripping over cords, air lines, or welding leads while entering or leaving the enclosures.

Keeping employees safe from potential arc-flash hazards

Gateway Generating Station

Pacific Gas & Electric Co

Challenge. The plant's 4160-V and 480-V switchgear installations present a great risk to employees when racking and grounding. Even with 100-cal flash gear and the installation

Gateway Generating Station

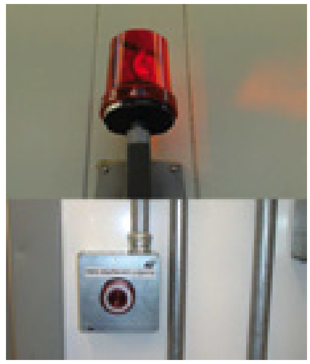
530-MW, gas-fired, 2 × 1 combined cycle located in Antioch, Calif

Plant manager: Ronald A Gawer

Key project participants:
- Steven Eck, power plant technician
- Adam Hankins, power plant technician
- Steven Anderson, maintenance supervisor
- Ben Stanley, operations supervisor

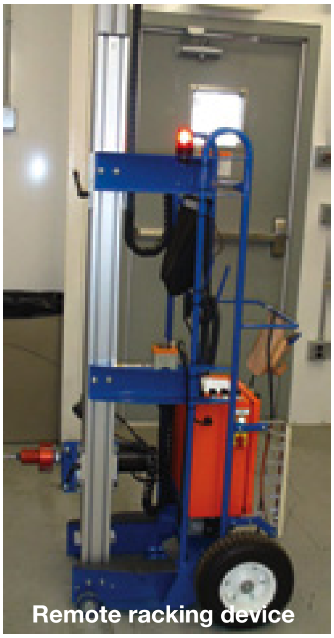
Racking breakers at Gateway

Signs posted on the entry to each room



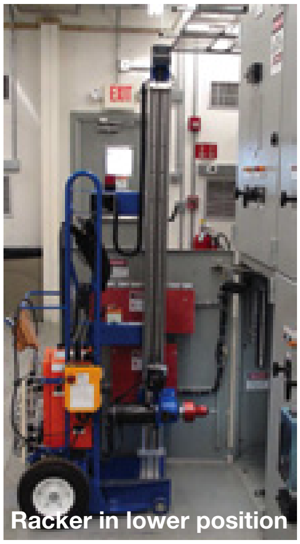
Rotating beacon and pushbutton

Video monitor



Remote racking device

Wireless remote



Racker in lower position

Front view of camera and light

4160-V switchgear room

100 cal flash suits

of maintenance switches, the potential for arc-flash hazards has always been of concern to the employees, management, and regulators.

Solution. It was decided that a fully remote-controllable system would be the safest way to mitigate the hazard. The plant team worked together to spec and procure an upgraded remote racking device that would fit all of the site's 4160-V and 480-V load-center breakers, contactors, and grounding buggies (photos).

CBS ArcSafe, Denton, Tex, supplied a remotely operated, wireless-actuated racking device which is also equipped with a camera and lighting system, so that the technician can see the breaker, contactor, or grounding buggy while it is being racked in or out. This is all done outside of the room well beyond the arc-flash boundary.

In addition to the remote racking device, plant personnel implemented a warning beacon and signage on all of the switchgear-room entrances to warn others when work is in progress.

Results. Employees are completely out of the arc-flash boundary when racking in breakers, contactors, and grounding buggies. Personnel that are not involved in the racking evolution are warned to stay out of the area.

In addition to the obvious benefit of keeping the employees out of the potential hazard, it's important to note that the employees helped to drive the changes and upgrades and participated in the design and implementation. Management reviewed and approved the changes and supported the initiative financially. In doing so, it demonstrates a strong and continual commitment from the entire staff towards safety and an incredibly strong safety culture.

Area-specific hazard awareness SRAs (Safety Risk Assessments)

River Road Generating Plant

Owned by Clark Public Utilities
Operated by GE Energy Power Generation Services O&M

Challenge. Plant personnel identified that specific areas (not task specific) have inherent potential safety risks. By and large, work that does not require a work order and job safety analysis does not get potential risks reviewed. General safety-risk awareness of specific areas is often reliant on personal knowledge and experiences. General awareness of area-specific risks that may be obvious to site employees may not be as obvious to contractors and site visitors. Over time, if safety risks are not reviewed, the awareness diminishes.

Solution. Plant personnel collaborated to create area-specific safety risk assessments (SRAs) for various areas or zones in the plant and posted them at the entry of the area in order to raise awareness of safety risks for contractors, visitors, and new employees during orientation. A goal of the procedures is to review them with employees and update them as area hazards change.

Some examples of the hazards included in the document (Fig 10):

- Noise (hearing oncoming traffic)
- Ongoing breaker operation
- Fire system actuation
- Lighting
- Gating and doorways
- Area chemicals
- Machinery
- Surface conditions
- Surface temperatures
- Traffic areas
- Communication
- Required PPE.

Results. Besides providing heightened awareness of safety risks in many areas of the plant, the benefits of our SRA program include:

- Provided opportunity to evaluate engineered hazard controls
- All site employees' experiences and expertise are utilized in updating documents
- Area-specific hazard assessments can be added to work permits
- Expedites work permitting process, increasing work productivity with enhanced safety
- SRAs posted at entry to areas for "in the field" review
- Part of annual review process
- Communicates hazards to contractors prior to mobilizing to assist with work plans and task specific work permits.

10. Safety risk assessment

River Road Generating Plant

250-MW, gas-fired, 1 × 1 combined cycle located in Vancouver, Wash

Plant manager: Chetan Chauhan

Key project participants:
Steve Ellsworth, shift supervisor
Kenneth Roach, operations manager

OSHA Voluntary Protection Program (VPP)

Klamath Cogeneration Plant

Iberdrola Renewables

Challenge. The challenge put forth to our crew was to prove to ourselves and to OSHA that our safety policies and procedures are of premium quality. After graduating from the OSHA Safety and Heath Achievement Recognition Program (SHARP) we felt it was time to take the next step and advance our safety programs to the highest level.

Solution. During construction, all plant employees recognized the need for the facility to have a written safety and health management system. Employees, with management support, were responsible for the development of each part of the written plan. Management implemented the program in this manner to ensure ownership and buy-in from all employees. The plan has improved over the years and is considered a living set of documents.

Plant staff utilized OSHA members in a consulting role. Each safety program was scrutinized from a useful aspect and a regulatory aspect to ensure compliance but still maintain functionality. Once all of our policies and procedures were in place, we applied for OSHA SHARP status.

The OSHA SHARP program is limited to five years of participation,

which we completed in 2007. During the graduation ceremony, pursuing the OSHA Voluntary Protection Program (VPP) was recognized as the next step in advancing our health and safety programs. The leading factor in seeking this recognition was to prove to ourselves and to OSHA that our facility is going beyond the minimum compliance in regards to health and safety.

During a monthly safety meeting, the concept of VPP was presented with discussions of the requirements necessary to achieve this distinction. There was a clear consensus that applying for VPP was both desirable and appropriate to advance our health and safety programs. At the start of the VPP application process, all employees were informed of the process and how they could help in completing the application.

Employees were divided into four groups and tasked with reviewing the entire safety program to develop answers to the five sections of the application as they apply to our site. Each group had a team leader, who was a safety committee member that scheduled meetings and tasked others in the group to gather information. When a group finished with their section, they would exchange information with another group to get more input. After all of the information was compiled, the VPP application was developed. The five major categories for the application are:

- Management leadership and employee involvement
- Worksite analysis
- Hazard prevention and control
- Safety and health training
- Process safety management (PSM) supplement.

Upon completion, the application was submitted to OSHA for review. Our application passed the initial review process and a formal site audit was scheduled. The audit was extensive and extremely thorough. A punch list of deficiencies was generated, particularly in our PSM system and a 90-day deadline was set for implementation of all corrective actions.

A tremendous amount of effort from all members of the staff began. The larger holes were in the mechanical-integrity section of our PSM. Most of this work was associated with determining the Recognized and Generally Accepted Good Engineering Practices for every component of our ammonia system. This entailed identifying all items associated with the system including the injection grid, catalyst, and the control system hardware, and developing a life assessment and maintenance plan for each.

Klamath Cogeneration

500-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Klamath Falls, Ore

Plant manager: Ray Martens

Key project participants:
Tim Kelly, EH&S engineer
Greg Dolezal, maintenance manager
Bruce Willard, operations and engineering manager

There were also remedial efforts regarding operating procedures and document control of P&IDs used for lockouts. We also had to develop an Electrical Work Permit program in accordance with NFPA 70E and make several small wording changes throughout our programs.

Results. At the end of the 90-day period, another audit was performed to address the open issues. Our efforts were rewarded with VPP Star status, the highest level possible. Now we have the challenge of maintaining our program while continually improving it. VPP status allows us to network with other VPP industries and businesses to share ideas and help each other improve. Safety is not proprietary and it will always be our policy to improve our programs, as well as help others improve.

Calculating risk factors to ensure personnel safety

New Covert Generating Facility

Owned by New Covert Generating Company LLC
Operated by NAES Corp

Background. The Teams Operating Plants Safely program (TOPS) at Wolf Hills Energy LLC was awarded the "Best of the Best" for Safety in

New Covert Generating Facility

1100-MW, gas-fired, three-unit, 1 × 1 combined cycle located in Covert, Mich

Plant manager: Rich Evans

Key project participants:
The entire New Covert team

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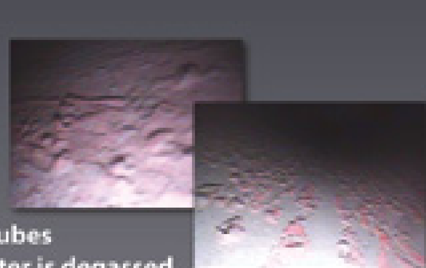

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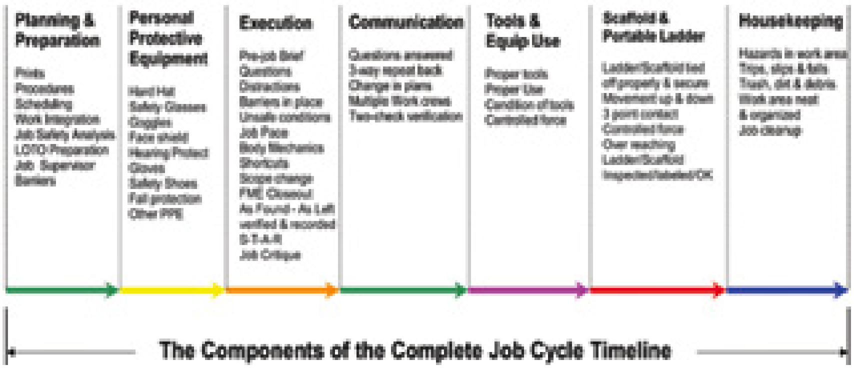
the "Best of the Best" for Safety in 2005. Since then, the program has matured significantly and has taken root at New Covert Generating Facility. Employees completed over 500 observations in 2011 and identified many opportunities to decrease risk of safety incidents along the way. The program now includes a complex database with a built-in "Risk Factor Calculator."

Challenge. If not handled appropriately, powerplant work can be risky business. Accidents, injuries, equipment failure, and other significant events all impact the quality of life for employees, as well as the bottom line. The foundation of the TOPS program is that all accidents, injuries, and events can be prevented, and they will be, if the interweaving risk factors are collectively understood and managed.

Solution. The Risk Factor Calculator used in the TOPS program helps to expose the compounding factors of risk often hidden in conventional analysis. Conventional risk analysis frequently excludes various causal factors that add to risk. Operating together, these factors can lead to accidents, injuries, and major plant and system events. We are routinely challenged by risk in our daily work. Success can easily mask and desensitize exposure to risk.



11. Observable job activities and conditions that influence risk

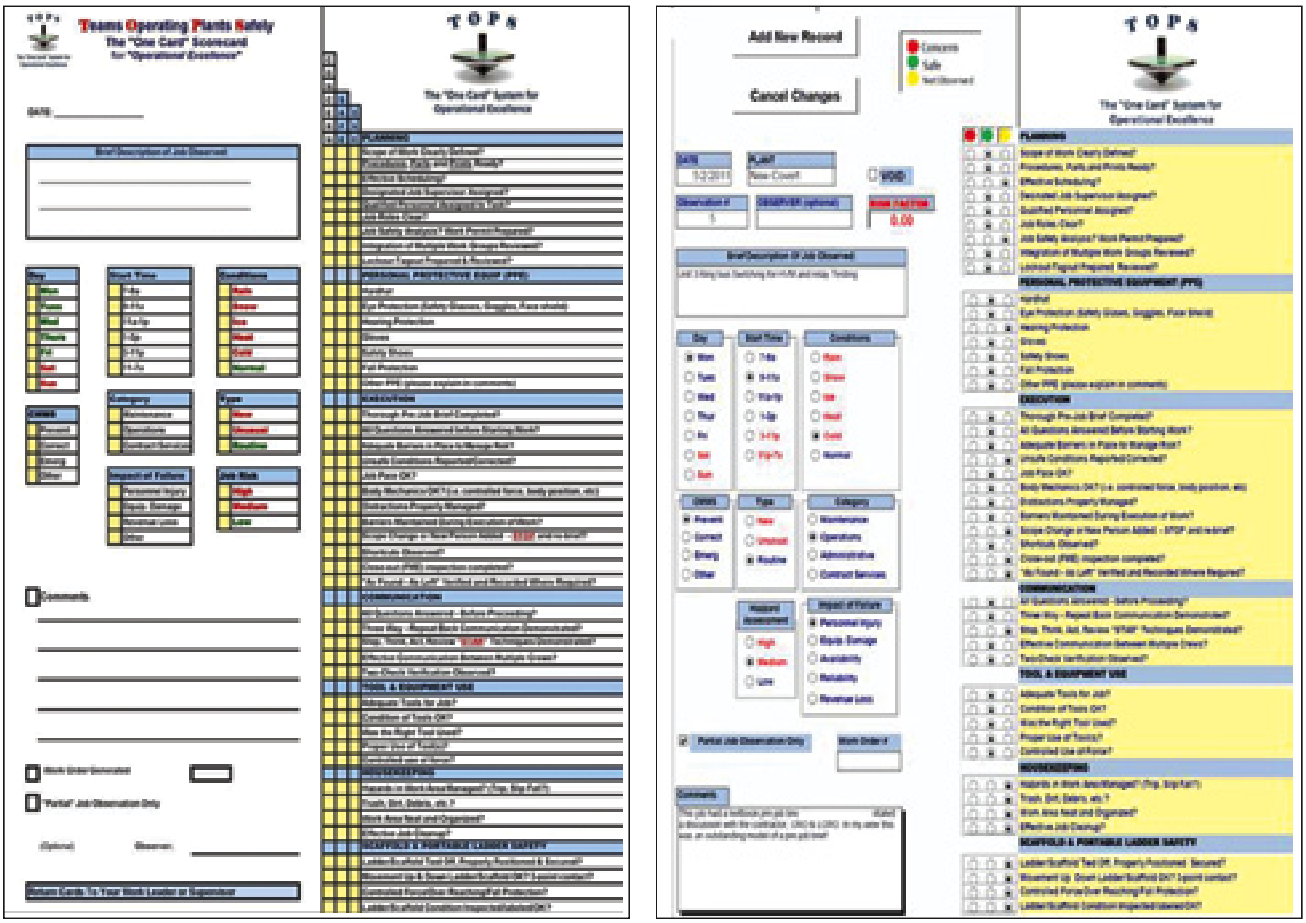
The TOPS observation findings conclude that many jobs ordinarily considered successful may actually contain a significant amount of risky activity. Root cause analysis (RCA) has proven over and over that the enemy of success is often the achievement of success. The TOPS approach for maintaining a safe workplace is to identify potential problems and fix them before they become bigger consequential problems.

The TOPS Risk Factor Calculator provides methodology and data for advanced insight to help illuminate risk factors, so they can be identified and more effectively managed. The job cycle timeline illustrated in Fig 11 provides a general snapshot of many of the observable job activities and conditions that influence risk.

Anatomy of TOPS program

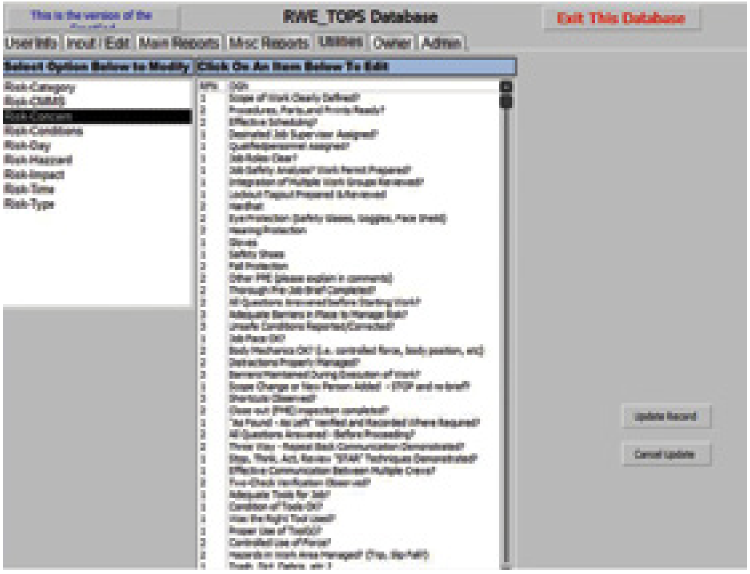
The risk factor calculator and the scorecard. The scorecard shown in Fig 12 is the TOPS data collection tool currently used at the plant to collect data about the jobs observed. The TOPS database screenshot shown in Fig 13 mirrors the scorecard with the addition of a built-in risk calculator.

The form is simple in that the observer walks through the obser-

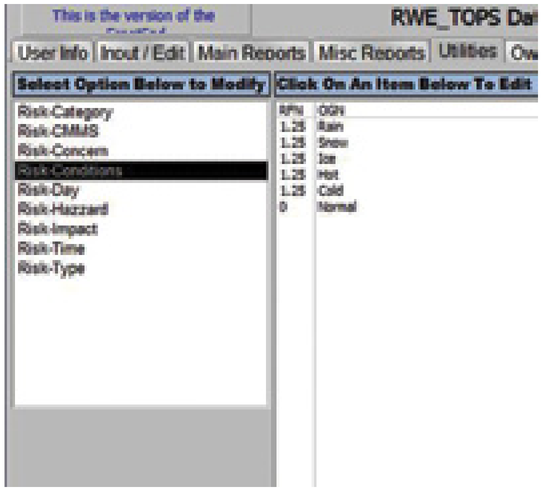


12, 13. TOPS scorecard (left) is used to collect data, screenshot at right mirrors scorecard but also has a risk calculator

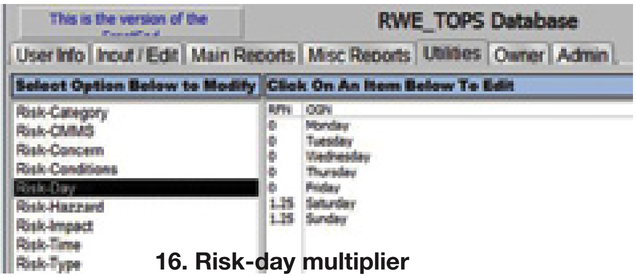

NEM
USA



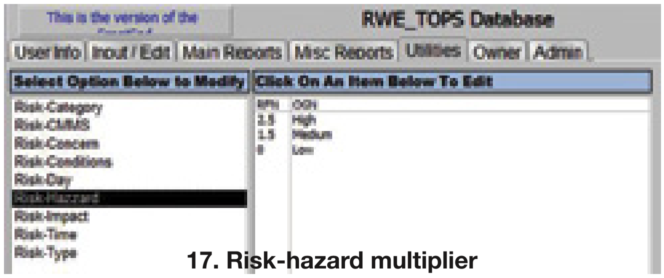
14. Level of risk is in column to left of column OGN which lists observable items or activities as shown on the scorecard



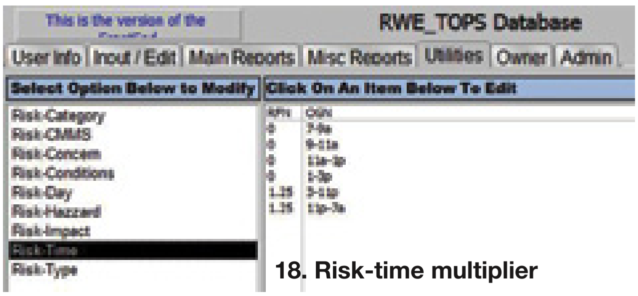
15. Database sums the total value of all combined OGN items observed and then multiplies them by the risk factors shown in Figs 15-19. This screen shot reflects risks associated with certain ambient conditions



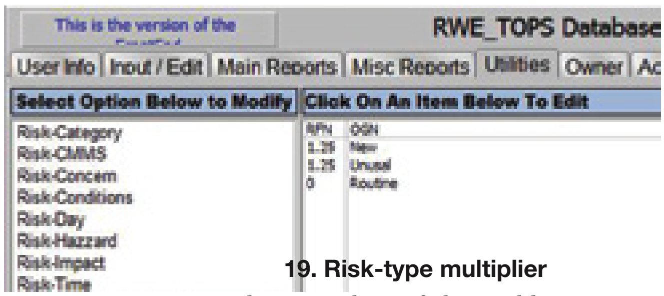
16. Risk-day multiplier



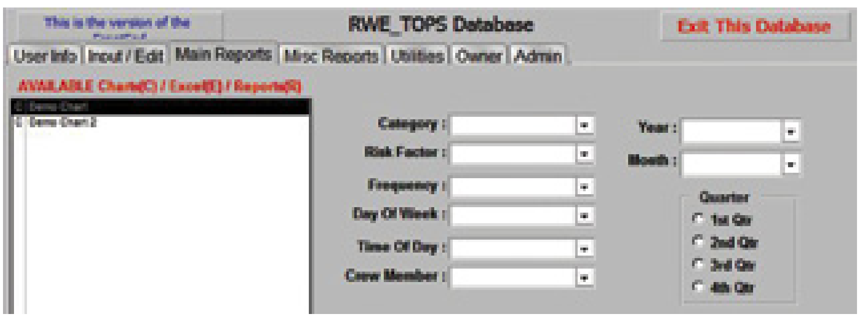
17. Risk-hazard multiplier



18. Risk-time multiplier



19. Risk-type multiplier



20. Miscellaneous reports section of the database is a powerful analysis tool

vation process while checking each appropriate box observed. At the end of the observation it is clear what the observer saw and equally important what he or she did not see.

The form also provides additional space for special notes about the job observed which can be made searchable in the database. You may notice on the form that there is a check box for a "partial" observation. It should be noted that it is perfectly acceptable for an observer to complete a partial observation since a complete one is not always practical with the time constraints of day-to-day activities.

How the scorecard works. Each of the major performance categories—planning, personal protective equipment, execution, communication, tools and equipment, housekeeping, and scaffold and portable ladder safety—have a subset of observable activities and expected behaviors. The observer uses the scorecard and checks blocks in each appropriate column near the right center of the page to determine if the subset of behaviors is considered "safe," a "concern," or "not observed."

"Safe" means the activity observed is clearly recognized as an expected risk-management behavior. An activity classified as a "concern" would require, at a minimum, a closer review to determine if the activity effectively manages risk and supports the team's mission of event-free operation. An activity classified as "not observed" is neutral to the observation and means what it implies. The subset of behaviors or conditions listed on the scorecard each point back to critical behaviors, if not present in the job cycle timeline may lead to or increase the probability of an accident, injury or system event.

The risk calculator and database. Fig 13 shows a screenshot of the

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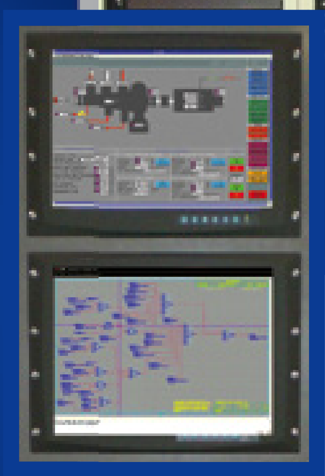

TurboNet is an open platform, custom configurable, integrated, DCS structured Turbine Generator Control System designed with the specialized features required for the complex control of modern steam and gas turbines, and their Generators (TurboNet is NOT PLC Based) Additional details available on our website.

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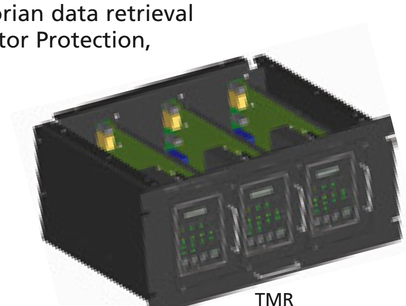
  - TSI & Vibration Monitoring Module w/Diagnostic Analysis and Plotting
  - EHC Servo Loop Control Module (includes MPU input from flow divider if applicable)
  - Sequence Of Events Module @1ms Time Stamping
  - Flame Scanner Monitoring (for Honeywell Scanners)
- New Upcoming I/O Module Features to be released in 2012
  - Combustion Dynamics Module (GTG)
  - Triple Redundant Power Load Unbalance Module (STG)
  - Shaft Voltage Monitoring Module
  - True TMR I/O Signal Flow
- Easily applied to Balance of Plant (BOP) functions
- HMI Trending for Time Based, X-Y, and Polar (vibration & balancing) plotting with seamless TurboNet Historian data retrieval
- Integrated Excitation Control, Generator Protection, and Auto/Manual Synchronization

Coming In 2012

- New 40amp Redundant Power Supply Chassis with Standard Lambda Slide In/Out Power Supplies
- New Control Processor Chassis
  - Available in Standard Redundant/ Hot Standby
  - ***Triple Modular Redundant (TMR) Processors with Signal Voting***



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Risk Factor Calculator and database front end. The front end of the database mirrors the actual field version of the TOPS Scorecard used by technicians to collect data. An Excel spreadsheet is optional and can be used with portable handheld devices, such as the iPhone, iPad, or Android devices, and is near completion. An observation can then be easily uploaded to the database from the handheld device.

Risk-concern values. The observation-generated name (OGN) column lists the observable items or activities as shown on the scorecard (Fig 14). To the left of the OGN column is the risk-factor number (RFN) column. The RFN column provides an assigned value to an activity that ranges from 1 to 3. The number can be adjusted up or down to the user's satisfaction. The value represents an agreed-upon exposure to risk. The database sums the total value of all combined OGN items observed and then multiplies them by the risk factors shown in Figs 15-19.

Risk-conditions multiplier is weather-related. Ambient conditions, such as rain, snow, ice, heat and cold temperatures influence job risk (Fig 15).

Risk-day multiplier. Saturday and Sunday work, especially unplanned, is generally considered riskier because of limited resources. It can be argued that some types of work are actually safer to do on Saturday or Sunday if detailed planning is completed in advance to compensate for limited access to manpower and other resources. This database multiplier can be adjusted to the user's preference (Fig 16).

The risk-hazard multiplier is somewhat subjective but useful to heighten employee awareness to potential added job risk (Fig 17). For example, if an assigned job is sweeping a floor at ground level the risk might be considered "low," since there is no apparent major risk added to complete the work. On the other hand, if the assigned job is replacing a pump and motor where lifting and rigging are required, the job risk might be considered "medium." In contrast, if the assigned job involved tagging, switching, and racking out breakers on a live bus the work might be considered "high." The purpose of making the distinction is to ensure appropriate barriers are in place to effectively manage the risk.

Risk-time multiplier. RCA findings indicate there is some correlation to increased job risk related to the time of day work is performed (Fig 18). If a job is started on either of the two night shift periods, 3 a.m. to 11 p.m. or 11 p.m. to 7 a.m. shown, the risk factor generally should be considered higher. Added risk-factor considerations are lighting, resources, turnover requirements, and potential employee fatigue if the job is occurring on an overtime basis, for example.

Risk-type multiplier. RCA findings routinely indicate that risk is added when performing new and/or unusual tasks (Fig 19). New tasks present training, procedure, and process-control challenges. Unusual tasks also present continuing-training and knowledge-based challenges. Employees must be adequately equipped to ensure the highest probability of success.

The miscellaneous reports section of the database is a powerful tool for analysis— particularly for tracking and trending (Fig 20). Other types of reports can be added as desired. All information collected can be sorted and manipulated to produce numerous types of reports.

Tag system helps mitigate fall hazards

Astoria Gas Turbines

NRG Energy

Challenge. Our plant staff stresses the importance of fall protection when using chain falls, lever hoists, come-alongs, slings, and harness safety equipment during plant maintenance. From a safety standpoint, everyone who works in the utility industry has witnessed many events, both good and bad. Vince Lombardi, the legendary coach of the Green Bay Packers stated the following:

"The achievements of an organization are the results of the combined effort of each individual—individual commitment to a group effort—that is what makes a team work, a company work, a society work, a civilization work."

There is no substitute for "teamwork" when it comes to fall protection, and we have developed a tag system to help protect the facility's most valuable assets: our employees. In the business world we live in today, the rallying cry seems to be "we can do more with less." This has forced our staff to become more polished workers, more conscientious of work surroundings, and always think "safety first."

The Astoria GT site includes W191, W251, and Pratt & Whitney units. Those familiar with these units know that at times during overhaul and repair there are many hazards that our employees deal with. We have a staff that varies in age, experience, and business backgrounds. What we all have in common is a real honest approach to safety awareness. We look out for each other and the vendors that work onsite.

A daily safety meeting before we head out the door to start our jobs illustrates our company is very committed to a safe, healthy workplace. This is a joint effort by both plant management and O&M staff working together to identify potential hazards and work together on solutions to eliminate these hazards.

Solution. Our site manager lets everyone speak freely at our daily safety meetings. His philosophy is very simple: "If you see something, say something." Many years of experience in this industry have taught the staff that group participation is what safety is all about. Out of these daily safety meetings we have come up with "best practices and procedures" for fall protection.

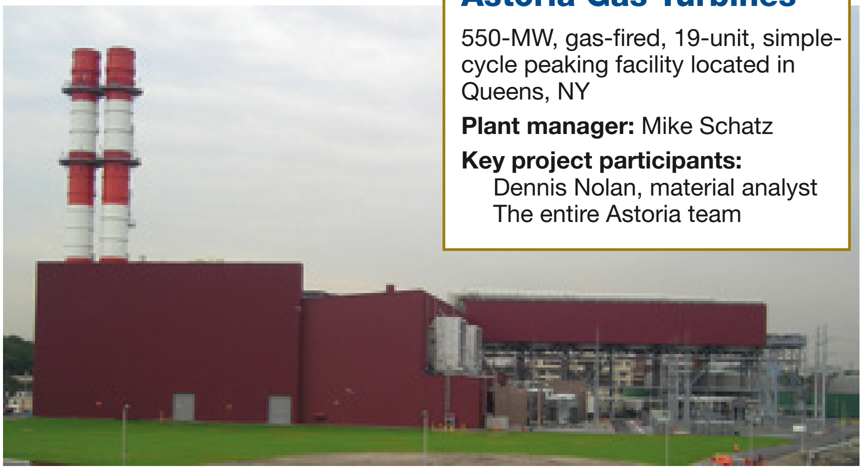
One key to developing this "safety first" culture is to emphasize to our younger employees that even though a vendor has approved/stamped its certificate of conformance on our chain falls, lever hoists, come-alongs, slings, and harness safety equipment, it's your

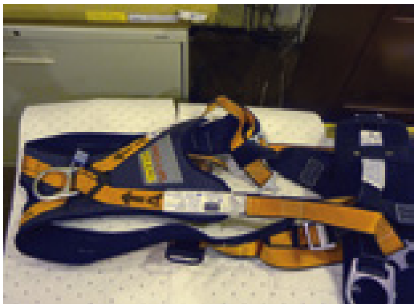
Astoria Gas Turbines

550-MW, gas-fired, 19-unit, simple-cycle peaking facility located in Queens, NY

Plant manager: Mike Schatz

Key project participants:
Dennis Nolan, material analyst
The entire Astoria team





21. Safety equipment always is inspected by a qualified plant employee before use, regardless of vendor certifications

22. Each item of safety gear has a tag number card

responsibility to inspect it every time you use it. If you don't see our tag on it, don't use it.

Open communications with our mechanics, performance technicians, operators that wear this particular equipment is the best route to follow for a successful tag system. As with any set of comprehensive safety policies, written procedures are followed in reference to harnesses. In this particular case, regardless if it was just inspected by the vendor, a harness would be inspected by one of our employees before use (Fig 21). He or she would look to evaluate the following:

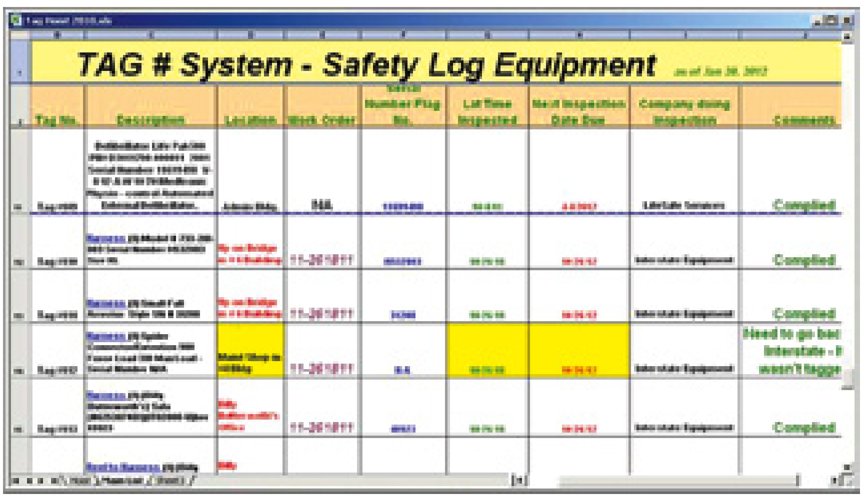
- Webbing—check for frayed/ripped edges, broken material/fibers, pulled stitching, cuts, welding burns, or foreign matter damage
- Rings—inspect for damage such as cracks, breaks, and cut edgings
- Buckles—inspect for wear and tear, anything that stands out as a danger
- Lifelines—a thorough look for visible damage (might want to strength-test it yourself while grounded).
- Anchorages and their connectors. We especially stress this: You are only as safe how you are anchored so make sure that this item looks safe for use.

A designated storage area for the fall protection equipment is key. The area should always be kept clean and accessible only by employees qualified or chosen to store and maintain the equipment. A usage card on the equipment shows who/why/when the items were used. Most importantly, each item should be labeled with a tag number card (Fig 22).

The vendor inspection information must be on these items at all times (specifically, inspection date, model number, serial number, manufacturer, weight capacities, born on date). Remember our site manager's motto, "If you see something, say something." Well in this case, if you don't see something like a tag number or vendor inspection date, say something as well.

Effective communication is what this project was built on and diligent record-keeping on these items is essential (Fig 23). The station planner runs "preventive maintenance" work orders through our Maximo system on a scheduled basis. Most of all, know and trust the firms servicing your safety equipment. Make sure that they meet OSHA standards and when they return chain falls, lever hoists, come-alongs, slings, and harness safety equipment, you get their certification. Read it carefully. Take nothing for granted and match it up with all vendor paperwork like packing slips, invoices, and notes.

Results. An enviable plant safety



23. Diligent record-keeping is essential

Tie-off safety during outages

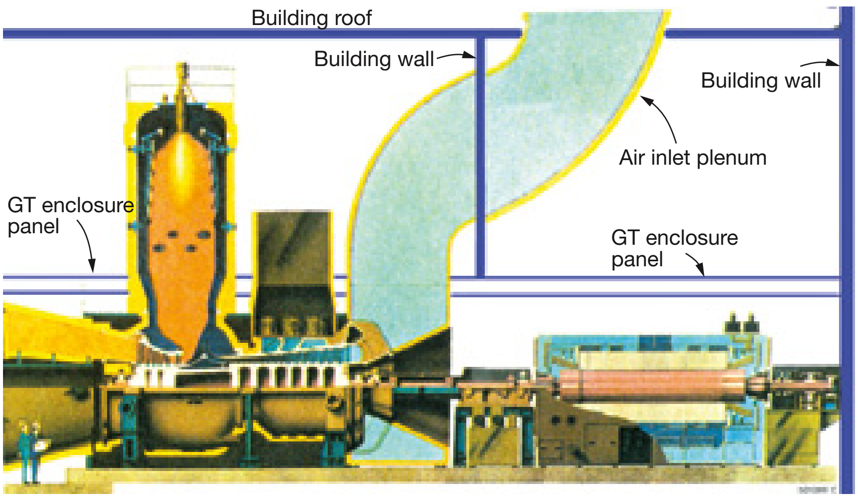
Hopewell Cogeneration Facility

IPR-GDF Suez Energy North America

Challenge. During maintenance outages, the roof panels for our gas turbine enclosures have to be taken off for access and equipment removal (Fig 1). This presents a number of problems:

- The panels have to be lifted somehow
- Personnel removing the panels have nothing to be tied off to
- Most of the equipment does not have, nor does it need, guard rails during normal operations, but when maintenance is being conducted, guard rails are necessary.

Solution. These problems have been addressed and process improvement continues. Temporary guard rails have been fabricated and are stored in the



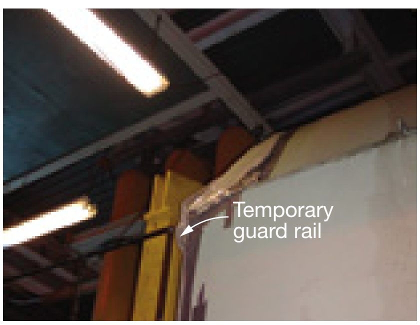
1. Roof panels for gas-turbine enclosure must be removed to access the engine

Hopewell Cogeneration Facility

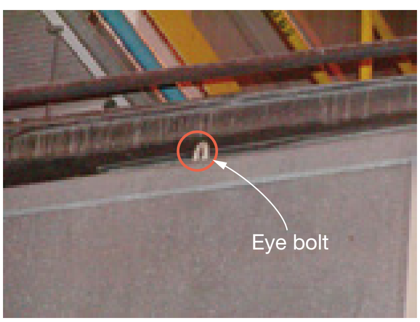
365-MW, gas-fired, 3 × 1 combined-cycle cogeneration facility located in Hopewell, Va

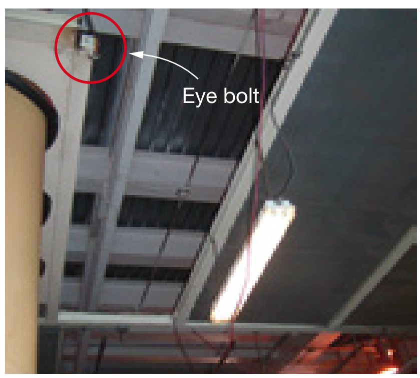
Plant manager: Bob Greene

Key project participants:
Steve Henry, maintenance supervisor
Jamie Dalton, senior mechanic
Input from all operators



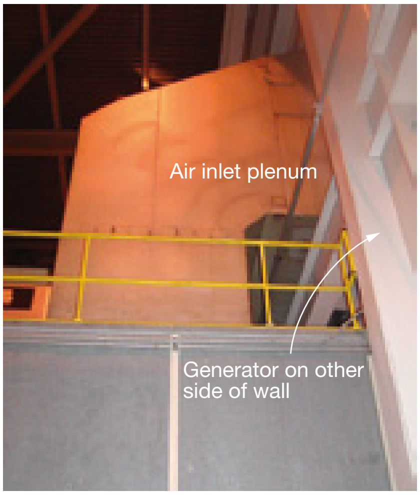
2. Guard rails must be taken down before removing the roof panels





3, 4. Eye bolts are installed just prior to removing the roof panels

5, 6. Cable and its attachment point are shown at the left; cable is stored on top of the generator enclosure (right)



7. Generator enclosure is on the other side of the wall supporting the air inlet plenum

gas turbine enclosure when not in use. The rails are attached by a number of methods. Some can be bolted to the equipment, while other have attachment points welded in place. The guard rail in Fig 2 has slots that the rails will fit into. Once removed, the slots are covered and cannot be seen and present no hazards.

For roof panel removal, each panel has inset attachment points at each corner. There are additional insets for attaching roof-panel guard rails that are on the edges. When the panels are ready to be removed, eye bolts are screwed into the insets and the panels are lifted out of the way (Fig 3). Once the panels are put back, the eye bolts are removed so there is no trip hazard. Note the eye bolts in the top and left side pictures. Fig 4 shows a unit with one panel removed.

The question of where to tie-off remains a problem. If there are beams overhead, a beam trolley can be used but most of the time it is not that simple. Plant personnel welded attachment points in a number of locations above the roof panels. During outages cables are run from these attachments while removing the roof panels. The cables are stored on the gas turbine enclosures until the panels are replaced then the cables are removed, inspected and stored until the next outage.

In the following photos you can see the cable stored on top of the enclosure and the attachment point. This was used for the generator work where panels had to be removed to remove equipment and take the generator rotor out. Fig 5 shows the cable and its attachment point. The companion picture shows the cable stored on top of the generator enclosure (Fig 6). There is another attachment point on the opposite end of the generator. Turnbuckles are used to keep the cable tight. The generator enclosure is on the other side of the wall supporting the air inlet plenum (Fig 7). The plant has found that using different fittings where the cable can slide or quickly attached and detached makes a pattern that will cover large amounts of roof space.

Results:

- Use cables to tie off where there are no tie-off points. Get creative: Erect poles or beams to attach cables to. In most all cases something can be found that will provide some kind of attachment point for fall protection.
- Attachment points on roof panels are made so that eyebolts can be attached and removed for safe lifting and are not a trip hazard when not in use. The attachments are also good for attaching guide lines/ tag lines. Attachment points can be used for guard rails in some cases when the panels are in their normal configuration.
- Temporary guard rails can be fabricated for outage use.

These are some simple solutions to keep our workers safe, and it is our hope that everyone is already using these ideas.

Removable turbine-compartment outage roof for 7FA

Dupont Sabine River Works Cogeneration Facility

DuPont Company

Challenge. The location of our facility in a hot and humid, seaside climate presents many issues concerning heat stress, weather, and sun exposure. During planned and unplanned outages of our 7FAs, the turbine-compartment roof requires removal, which leaves the compressor and turbine sections of the units exposed to the elements.

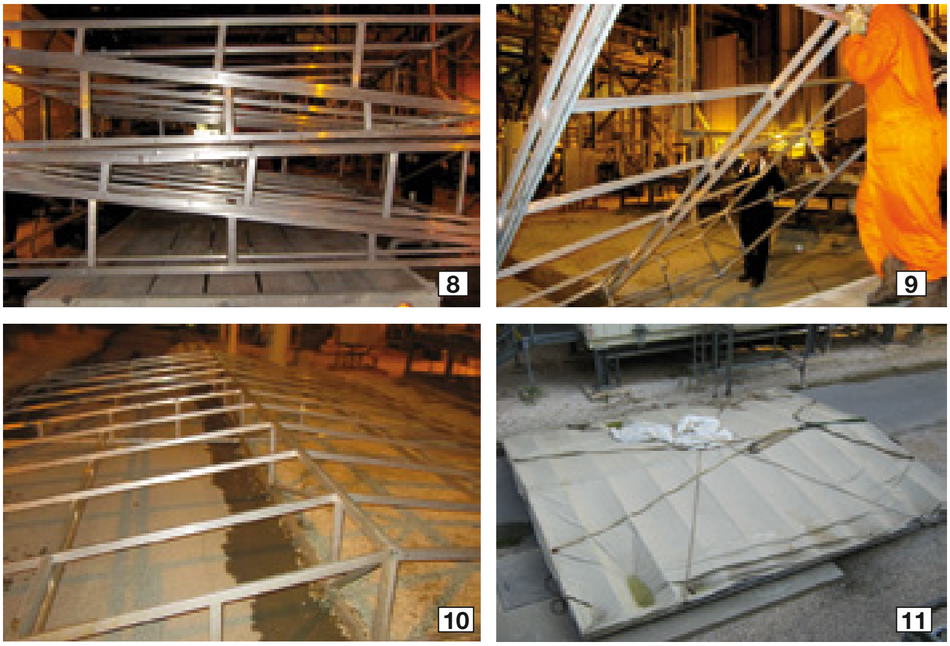
Once the piping, combustion parts, upper shells, and rotor are removed, maintenance personnel begin the tasks of compressor stator vane removal, turbine nozzle block and shroud block removal, stator slot cleaning, and various other half-shell tasks.

This required maintenance crews to be on the unit's half-shell exposed to all the elements without shade or cover. Unexpected thunderstorms and hot temperatures caused work delays and low productivity, which extended outages.

Solution. Turbine compartment dimensions were obtained through drawings and field measurements, and a lightweight, fire-retardant, easy on/easy off outage roof was fabricated. Outage roof frame construction was lightweight aluminum square tubing that could be assembled or disassembled in two halves in case removal is required for crane access.

The outage roof is delivered to unit area from laydown yard on a wagon in four pieces (Fig 8). Maintenance crews can easily lift sections of outage roof off of the wagon and handle them during assembly (Fig 9). Frame sections are bolted together on the ground (Fig 10).

Because the roof is in sections, it makes it possible to remove a section without removing the entire roof, when lowering in compressor casing or turbine casing hardware. The cover is of a sunblocking material, and attached



Dupont Sabine River Works Cogeneration Facility

420-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Orange, Tex

Plant manager: John R "Bobby" Laughlin

Key project participant: T C Austin, mechanical specialist

8-11. Outage roof structure is moved to unit area from storage (8) where it is easily handled (9), and set out on the deck for assembly (10). Fully assembled, the roof can be set on and taken off the turbine compartment easily (11)

by snaps, enabling quick removal/installation. Once the roof is completely assembled, it can be set on and taken off the turbine compartment easily using shackles and chokers (Fig 11).

The roof was attached to the turbine compartment walls by using the existing roof bolting holes and metal clips. The clips are slotted on the bottom side (side holding it to turbine compartment walls), to expedite removal/installation. The holddown bolts can be loosened enough to release the clamping side of the clip and removal/installation accomplished without removing all bolting.

The outage roof framing is conveniently stored in our plant laydown area in two halves without worries of rust and deterioration (another geographic problem). Sun cover can be folded compactly and stored with the clips in our parts warehouse, away from the elements, without taking up a lot of space.

Results:

- More productivity by OEM and site maintenance personnel resulting because of less exposure to the hot sun and unexpected thunderstorms. Crews can now work during any weather: hot, cold, sunny or rainy.
- Better scheduling ability for incoming parts that had to be repaired in OEM shop since casing work could be accomplished without interruption.
- OEM maintenance crews seemed to have a better attitude, and achieve better quality on tasks during hot summer days.
- Decrease chances of heat exhaustion/heat stroke cases.

Emergency retrieval access for W501B No. 5 bearing tunnel

Edward W Clark Generating Station

NV Energy

Challenge. The plant operates four W501B combustion turbines. Access to the No. 5 bearing tunnel is limited and it is impossible to retrieve someone without completely removing the roof which requires considerable effort—including disconnecting electrical wiring and performing lifts with the overhead crane.

Solution. This issue was finally resolved by the plant's safety committee by installing a hatch door on the roof where an emergency retrieval tripod could be setup rather than performing a complete roof removal (Fig 12). Hand rails were also installed to facilitate safe retrieval of personnel.

Edward W Clark Generating Station

1102-MW, gas-fired, combined cycle located in Las Vegas, Nev

Regional plant director: Tom Price

Key project participant:
The Clark Station safety committee

Results. This retrieval process was tested and validated by qualified confined-space rescue teams for effectiveness.

12. Roof hatch facilitates confined-space rescue

Combustor-enclosure safety systems

Rokeby Generating Station

Lincoln Electric System

Opportunity. The site has two Alstom 11N1 combustion turbines with single-silo EV combustors. Both units are dual-fuel capable, with water injection for fuel oil emissions control and power augmentation, which requires a large number of pipe connections in the combustor enclosure.

In addition to the combustor piping maintenance issues, the combustor enclosure's vent fans, lighting, and fire detection systems are in elevated locations, requiring significant preparation and outage time to service.

Finally, we were concerned about the restricted enclosure access that would result from using the OEM's standard ladder system. An integrated safety program endeavored to address the safety and maintenance efficiency issues associated with the combustor enclosures.

Solution. In order to reduce the operational safety issues and minimize

Rokeby Generating Station

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

Plant manager: Bruce Barnhouse

Key project participants:
Dan Dixon, project engineer
Tom Davlin, engineering manager

2013 BEST PRACTICES Awards

to gas-turbine-based powerplants (combined cycle, cogeneration, peaking)

Categories: Management, O&M, Safety, Design, Environmental
Deadline for entry: December 31, 2012

Judging/recognition: All entries will receive industry recognition by way of a profile in a special editorial section on Best Practices published in the Q1/2013 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 goals of improving performance, reliability/availability, and safety, and reducing emissions and O&M costs.

RULES

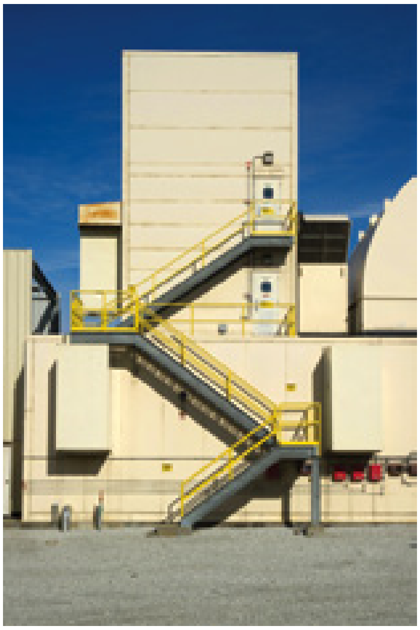
1. Entries accepted only from employees of North and South American powerplant owners and third-party firms with direct responsibility for managing the operation and maintenance of gas-turbine-based electric generating facilities.
2. Maximum of three entries from the same powerplant.
3. Entries must be received by midnight December 31, 2012 via regular mail/courier, fax, or e-mail.

TO ENTER

1. Award category (select one): Plant or Fleet Management, O&M, Safety, Environmental Stewardship, Design.
2. Title of Best Practice.
3. Problem: 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.
6. Name 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).

Suggestions: (1) Do not mention the name of your company or plant when completing Parts 2-5. This is the information that will be submitted to the judges. (2) Limit your response to Parts 1-5 to the equivalent of two pages of single-spaced 12-pt type. (3) Add photos, drawings to support entry.

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



13. **Steps and landings** are much easier to navigate than ladders to access combustor

maintenance outage times associated the combustor systems we implemented several enhancements, including:

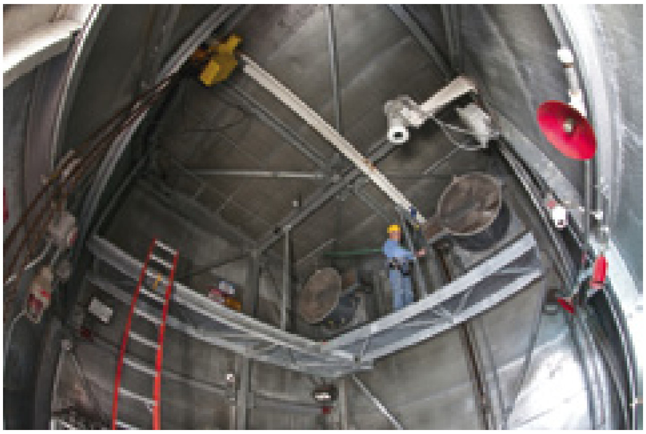
- Installing steps and landings versus the standard ladder system for combustor access (Fig 13)
- Installing camera systems to remotely monitor the combustor enclosure systems
- Installing a maintenance platform with movable sections to allow easier and quicker access to the upper level combustor systems (Figs 14, 15).

Results. Installation of the access steps and landings were completed as part of the original CT installations. The stairway allows much easier and faster access to the combustor enclosure increasing maintenance efficiency and improving emergency egress/access.

The pan, tilt, zoom camera system was installed to allow operators to remotely monitor enclosure conditions during unit operation, reducing the need to access the combustor enclosure while the unit is running.

The maintenance platform design and installation were completed as the latest phase of the safety program. The platform includes fixed and movable deck sections with integrated fall- protection tie-off systems. The movable sections enable the operator to move to different sections of the enclosure while also allowing for removal of deck sections for combustor maintenance and component removal.

The maintenance platform also significantly reduces the set up time for maintaining upper-level combustor components as well as reducing fall hazards. We estimate an annual reduction of approximately 160 hours of maintenance time associated with the elimination of scaffolding requirements because of the maintenance platform as well as improved access to the combustor via the steps (as opposed to the ladder system).



14, 15. Maintenance platform with movable sections facilitate maintenance

Fail-safing chemical dosage through color-coding (poka-yoke)

Central de Ciclo Combinado Saltillo

Owned by Falcon Group
Operated by Comego SA de CV

Challenge. The normal segregation and identification of chemicals in storage should be enough to avoid

CCC Saltillo

250-MW, gas-fired, 1 × 1 combined cycle located in Saltillo, Coahuila, México

Plant manager: René Villafuerte

Key project participants:
Developed by Roberto Hernández, maintenance manager

Implemented by Jesús Urbina and Rossana Gómez platts

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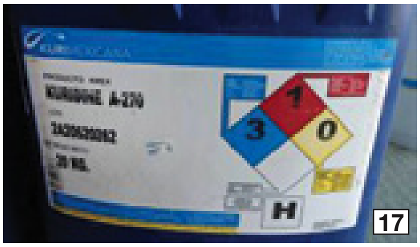
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16-20. Distinctive color-coding differentiates among various chemicals

any trouble. However, because of the multiple chemicals used in the plant for volatile HRSG treatment, cooling-systems additives, and water-treatment-plant reagents, and taking into account that the field technicians are not chemicals experts, there is the chance of a mix-up between ammonium hydroxide (steam-drum pH modifier) and sodium hydroxide (CEDI—continuous electrodeionization—cleaner).

Also, confusion between oxygen scavenger Kuridelight and membrane antiscalant Kuridine is a serious possibility based on the similarity of their names (Figs 16, 17). Compounding the problem, there several systems in the plant that require similar chemicals in the same area.

Solution. Inspired by the poka-yoke system (Japanese for "fail-safing"), the plant implemented the use of distinctive color-coding in order to differentiate possible confusion. The plant chemist also identifies each container with a color label during receipt of each chemical shipment (Fig 18). The containers are then stored in the corresponding area of chemical warehouse (Fig 19). Each chemical reservoir also has a color strip to identify where the chemical should be refilled (Fig 20). Bright and strident colors are specifically selected in order to prevent any confusion, not only with other chemicals, but with another kind of identifications on the pipe lines.

Results. CCC Saltillo has effectively taken the guesswork out of chemical refilling by simplifying and fail-safing the process, streamlining field technician training (no chemical knowledge required), and avoiding a real risk of chemical mix-up that has had severe consequences elsewhere in the industry.

Metal scaffold improves safety during turbine maintenance

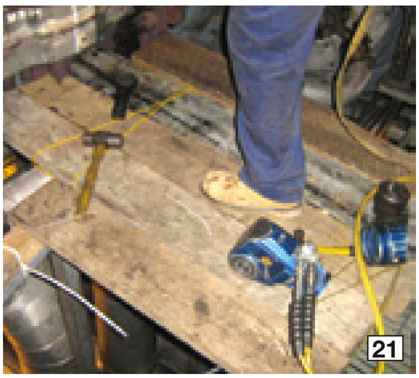
Termoemcali

Owned by ContourGlobal Latam SA
Operated by NAES Corp

Challenge. Workers are exposed to various risks during any routine major maintenance on a combustion turbine. During such work, a large number of workers walk by the turbine engaged in diverse activities such as using hand tools, lifting, welding, drilling, polishing, etc. One of the greatest dangers any worker can face is a fall from the side platform, nearly 10-ft high, which can be fatal.

According to the International Labor Organization, work done at height has the highest rate of death in the workplace. Almost 70% of fall

> **Termoemcali**
>
> 250-MW, dual-fuel, 1 × 1 combined-cycle peaking facility located near Cali, Colombia
>
> **Plant manager:** Fabio Ruiz
>
> **Key project participant:** Alex Martinez, maintenance planner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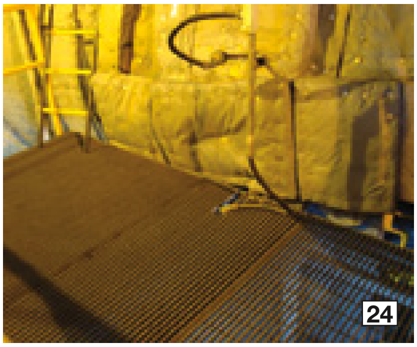
21-23. Wood decking has some limitations for use as work platforms accidents result in a fatality because of severe injury. To minimize such risk, companies performing maintenance tasks typically request that plant owners install and set up scaffolding with wooden platforms to allow employees to safely perform the work (Fig 21).

Because of the uneven lateral area of the turbine and limited space, it is almost impossible to cover all the gaps with wood decking, and the risk of falling still remains high (Fig 22). In addition, the wood is at risk of breaking at any time because of the amount of weight placed on it (Fig 23).

Solution. To be consistent with its policy of occupational safety and health, including a commitment to prevent hazards and maintain the health and safety of everyone at its facilities, the owner's management manufactured removable metal platforms, equipped with guardrails, to be installed on each side of the combustion turbine during maintenance activities (Figs 24, 25). Spacing between the newly created metal scaffolding and the turbine is minimal and the material is able to hold significantly more weight and provides greater stability (Fig 26).

Results. The newly created metal platforms allow maintenance activities to be conducted safely. During the last major maintenance of the combustion turbine, the labor force included 17 contractors and 10 plant personnel working in two 12-hour shifts. All work was conducted without a single fall incident or accident.



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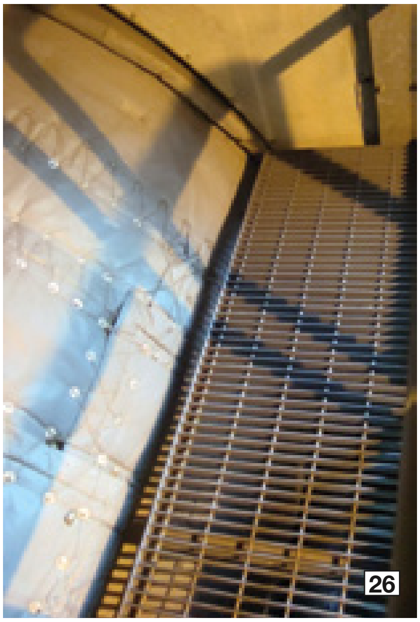

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24-26. Removable metal platforms equipped with guardrails have advantages over wood

CT enclosure general lighting, power

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

Challenge. The operation of a frame-size combustion turbine creates an environment that does not allow the installation of lighting and power fixtures. During outages, when work in the turbine compartment begins, there are a number of difficulties to supplying sufficient light for the more detailed work and power to operate electric hand tools in the compartment. Workers utilized the sparse outside receptacles for lighting and hand tools via extension cords pulled through the open doors.

Tenaska Virginia Generating Station

885-MW, gas-fired, 3 × 1 combined cycle located in Scottsville, Va

Plant manager: Robert Mayfield

Key project participants:

Sam Graham, maintenance manager

Neil Pierce, I&C technician

Solution. The safety committee had a clear set of objectives to solve the problem:

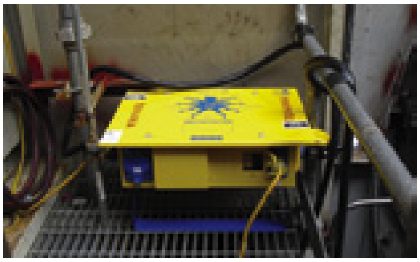
- Lightweight, modular, and universal: The system had to be easy enough to unpack and install so it would be used.
- Cost effective for power distribution
- Minimal manpower for setup
- GFCI protected
- A method to enter the turbine compartment without going through a door.

The original thought was to build a custom product that would meet all the needed criteria, but the discussion of parts and labor costs seemed added up to more than it would cost to purchase a system.

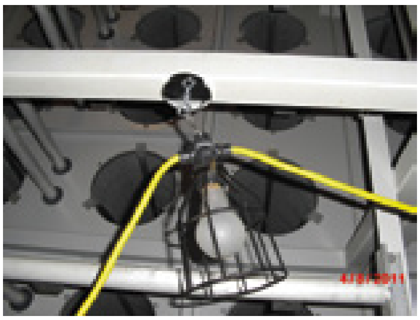
We started by installing 480/240-V transformers in each turbine electrical control building (Fig 27). Conduit was run from the transformer to a fusible disconnect that powers the 50 amp receptacle. A sealable penetration was placed near the wall of the enclosure and the receptacle to provide a short run for the power cord to be connected to the skid.

If an additional skid is needed, workers can simply connect a cord to the outlet of the first box outlet to the inlet of the second skid which is clearly marked (Fig 28). Each individual circuit is GFCI protected and has individual over-current protection. In this configuration, a single fault does not interrupt the work of everyone else.

27. 480/240-V transformers were installed in each turbine's electrical control building



28. Each GFCI circuit in the skid has over-current protection



29. Magnetic plates make it easy move lighting fixtures

This system includes fixtures in the compartment that allows for use string lights rated at 150 W per fixture. These are used in the upper and lower sections to provide a well-lit workspace. Each fixture is attached to the wall of the enclosure using a magnetic plate attached by a stainless steel "S" hook which makes them easy to install and to relocate (Fig 29).

Results. We have eliminated the need for multiple extension cords, reducing tripping hazards as a result. This system provides a safe source of power for multiple users with GFCI and over-current protection on each circuit. The workers have an abundant power source in a short distance from the work area. All of the components are lightweight and can easily be carried by a single person and installed in a matter of minutes.

During a recent outage when an unplanned hot gas path (HGP) started on an additional unit, the contractors asked for and installed the power boxes and lights because the convenience during work and ease of installation exceeded expectations. This system has also proven itself useful in working in the different sections of our HRSGs by providing the ability to supply independent power to individual modules quickly.

Improving safety in handling ammonia

Tenaska Lindsay Hill Generating Station

Tenaska Alabama Partners LP

Challenge. The facility's anhydrous-ammonia forwarding pumps did not allow for double-valve isolation during maintenance. These pumps are only required for use on very cold days. This requires additional maintenance and laying them up for periods of non-use. The system had single-valve isolation from the ammonia storage tank to the suction of the pumps, a potential safety risk for the O&M team.

Tenaska Lindsay Hill Generating Station

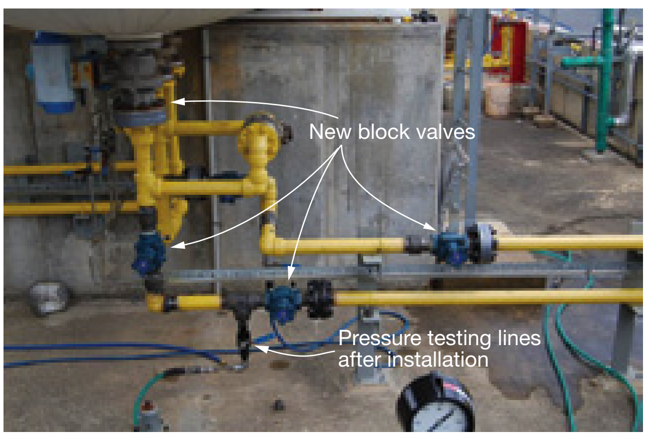
845-MW, gas-fired, 3 × 1 combined cycle located in Billingsley, Ala

Plant manager: Robert Threlkeld

Key project participants:
- Vince Crabtree, maintenance manager
- Bill Buster, plant engineer
- Eric Powell, LCRO
- Mark McKenzie, operations manager

Solution. Plant management decided to install double-block-and-bleed capabilities to the liquid suction line from the storage tank and liquid return line to the storage tank (Fig 30). A proposed piping modification drawing was prepared and circulated to the entire plant team for feedback.

Once the modifications were reviewed onsite, they were forwarded to corporate engineering for review. Once the review was completed by corporate engineering, the ammonia supplier was contacted for pricing the pump-out, de-gassing, and refilling of the



30. Single-valve isolation was converted to double-block-and-bleed to protect personnel tank. A detailed plan was written with documentation for all mechanical parts to be used, with technical specifications for each valve.

Since anhydrous ammonia is a PSM chemical for the site, a detailed management-of-change document was prepared for the modifications and went through a second approval process all the way through corporate engineering. Process hazard analysis was conducted for planned activities and pre-startup safety review was planned prior to putting the system back into service.

The modified piping was pressure and leaked checked prior to installation. Once the system was back together a whole system pressure and leak check was conducted with an air/nitrogen mix. The tank was then refilled with anhydrous ammonia.

Results. The new isolation valves have worked as anticipated and enhanced safety for personnel working on the system. The work was completed without incident or leaks.

Motion-triggered lighting guards plant fence line

Granite Ridge Energy

Owned by Granite Ridge Energy LLC
Operated by NAES Corp

Challenge. In May 2010, the plant had an incident where the south end of the high voltage switchyard perimeter fence had a hole cut into it. The plant does have security cameras capable of pan, tilt, and zoom, and plenty of lighting within the switchyard fence line; but the perimeter of the fence is inadequately lighted, providing intruders with the cover of darkness during nighttime operations.

After the repairs to the fence were completed, the team decided to be more proactive in deterring such incidents from occurring in the future. Possible solutions were discussed at team meetings, and it was agreed that illuminating the perimeter fence with motion sensor would be a good first step to take.

Solution. The current configuration of the switchyard lighting has a total of eight high- pressure sodium lights with an on/off light switch in the relay building, with the lights facing into the switchyard equipment. We realized that if we were going to deter would-be trespassers we would need lighting that would be powerful enough and fast enough to light up the largest possible area quickly. High-pressure sodium would not be the solution because it can take up to a few minutes to fully reach maximum output, thereby diminishing the element of surprise.

Technology to accomplish such a feat is very limited but during the request for quotation process, a vendor mentioned that new fast acting LED light fixtures are relatively new to the market. This new technology would be a perfect fit lighting the switchyard perimeter.

Results. Evidently, this new LED lighting technology was in high demand (or low supply) because we encountered a six-month lead time on the fixtures. When the fixtures arrived we mounted them on the backside of the original eight perimeter lights and faced them pointing outside of the perimeter.

We then hooked up 16 motion detectors wired to the line side of the existing lighting circuit so there were two motion detectors per light; with one motion detector covering the left side of the light fixture and one to cover the right.

The outcome now being that whenever a motion sensor picks up movement at any of the 16 locations, the entire fast acting perimeter lighting circuit is instantaneously illuminated.

Granite Ridge Energy

730-MW, gas-fired, two-unit, 1 × 1 combined cycle located in Londonderry, NH

Plant manager: William Vogel

Key project participant:
John Lytle, planner

Isolation-valve panel installation facilitates water-treatment sampling

MEAG Wansley Unit 9

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

Challenge. Multiple water-sample point isolation valves, which feed the water chemistry laboratory sample sink, are located throughout the site and require operation at various times. Many of these valves are located in difficult areas to access.

For example, some are located high

MEAG Wansley Unit 9

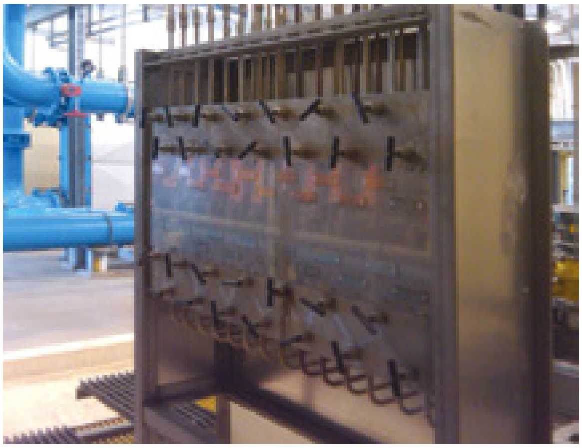
503-MW, gas-fired, 2 × 1 combined cycle located in Franklin, Ga

Plant manager: Keith Feemster

Key project participants:
- Jimmy Shehan, maintenance technician
- William Wright, I&C technician
- Andrew Buckhalter, site chemist

on a mezzanine level, others were underneath the decking, with several requiring the use of fall protection or a manlift to gain access. In addition, some are of a single-valve design, making double block and bleed impossible.

Solution. As part of the site's continuous improvement culture, all personnel are encouraged to recommend safety, quality, and time-saving ideas. As part of that program, the recommendation was made to design and install a single point to access all sample isolation valves. This panel would eliminate multiple hazardous tasks, greatly reduce man-hours expended, and enhance the safety of the site personnel by providing double block and bleed for all sample points.



Results. An isolation panel was designed and fabricated by site personnel (Fig 31). The panel was then installed adjacent to the water chemistry laboratory. Each individual sample point may now be isolated from a single central location. As an added benefit, with the new additional valve points, double block and bleed is now possible for all sample points.

31. Isolation panel allows isolation of all sampling points from one central location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Green Country Energy

Owned by J-Power USA
Operated by NAES Corp

Challenge. Our combined-cycle plant was not constructed with a plant discharge pond or outfall wastewater retention tank. As constructed, the cooling-tower blowdown and plant internal outfalls (unit sumps) are discharged into a common process water header where the pH and total residual chlorine levels are monitored and treated to remain within NPDES permitted levels, prior to being discharged into a river.

Sodium bisulfite is used for wastewater dechlorination with the expectation of an immediate reaction, and full dechlorination, at the point of contact. Unfortunately, said immediate reaction can only be achieved when adequate process water and sodium bisulfite mixing has occurred.

And, since the process water monitoring, chemical treatment, and mixing has to occur within seconds prior to discharge, the outfall monitoring instrumentation and chemical feed system must be extremely responsive to any changes in discharge water conditions (Fig 1).

Green Country's chlorine metering equipment produces chlorine residual readings approximately three minutes after the process water has already passed through the outfall, resulting in a delayed response in the dechlorination control process.

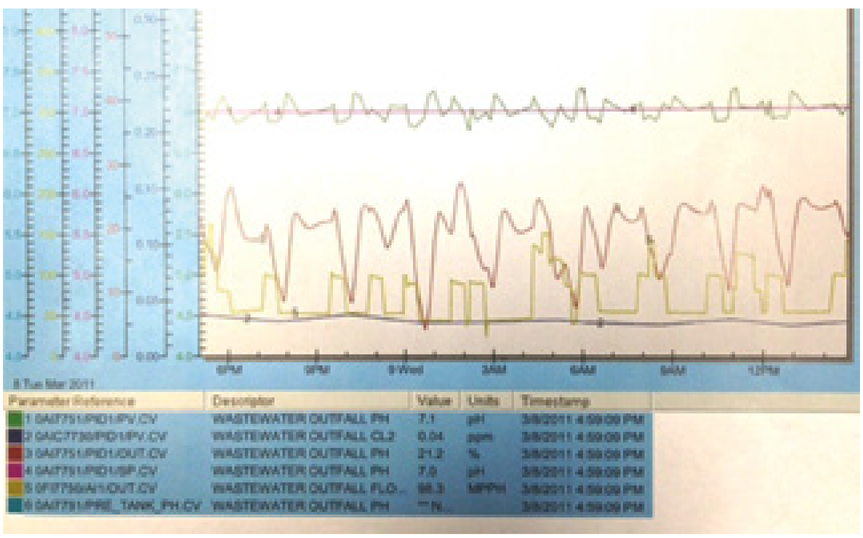
To further complicate things, each time a unit sump pump operated, the water chemistry would change considerably, causing a "swing" in the control system's response. As designed, the outfall monitoring and treatment system required unreasonably high attention by the O&M

Green Country Energy

800-MW, gas-fired, 3 × 1 combined-cycle located in Jenks, Okla

Plant manager: Rick Shackelford

Key project participants:
- Linne Rollins, compliance supervisor
- Dennis Bradley, operations manager
- Scott Helt, maintenance technician
- Scott Palmer, I&C technician



1. Outfall monitoring and treatment system, as designed, required a great deal of attention by O&M tech to maintain wastewater chemistry within permit limits

2. Residual chlorine and pH are monitored at the discharge of the 5500-gal retention tank to adjust treatment of water entering the tank technicians or risk an unpermitted discharge.

Solution. Following much discussion between management and plant personnel, the decision was made to improve the blending provisions and retention time through the installation of a 5500-gal retention tank (Fig 2).

The tank was added in series with the discharge line and included provisions to isolate, drain, and/or bypass the tank as needed. The pH and residual chlorine was monitored at the discharge of the tank, with the controls initiating treatment prior to the tank.

Results. The outfall retention tank installation has significantly improved the operation of the outfall and decreased the risk of a permit violation. As shown on the trend in Fig 3, the pH and residual chlorine are much more stable than before the installation of the tank. Weekly chlorine tests have proven consistently lower chlorine residuals in the outfall water, as compared to past years.

ACC gearbox drip pans prevent oil release, save time

Athens Generating Plant

Owned by New Athens Generating Company LLC
Operated by NAES Corp

Challenge. Each gearbox on the air-cooled condensers (ACC) at this 1080-MW, natural-gas fired facility contains approximately 8 gal of oil (Fig 4). The oil seal on each gearbox can fail without warning, potentially releasing oil into the ACC structure and ultimately reaching ground level where it contaminates the soil (Fig 5).

Any single-seal failure requires as many as six individuals working up to eight hours to clean up the ACC structure. If any oil reaches ground level, an outside agency must be contacted to perform onsite cleanup and removal of contaminated soil.

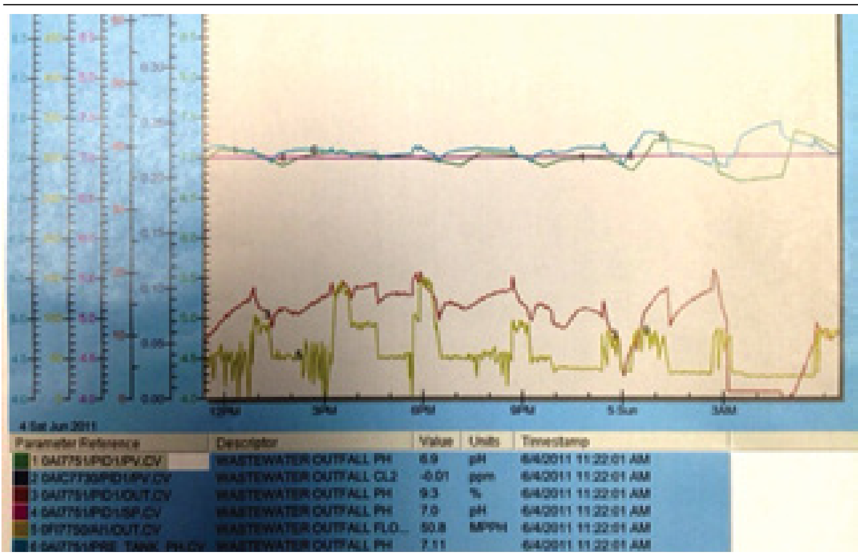
In addition, plant staff must call the NY Dept of Environmental Conservation Spill Hotline to report the release of oil into the environment.

Athens Generating Plant

1080-MW, gas-fired, three-unit, 1 × 1 combined cycle located in Athens, NY

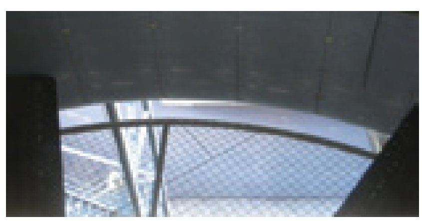
Plant manager: Dan DeVinney

Key project participants:
Colleen Fischer, EHS manager
Ken Cardona, operations coordinator
Dwayne Boyer, O&M manager



3. Retention tank enables consistently lower chlorine residuals in the outfall water and tighter control of pH

4. Gearbox for each ACC fan contains about 8 gal of oil



5. Oil has a clear pathway to the ground if a seal fails

6, 7. Drip pans catch any leaking oil

Finally, plant personnel are required to take soil samples to ensure that all contaminated soil has been removed from the spill area.

Solution. Plant staff came up with the idea to place a drip pan underneath each of the 54 gearboxes, both to catch any leaking oil and to provide a visual indication of when the gearbox seal needed to be repaired or replaced prior to the seal failing (Figs 6, 7). The 54 drip pans were manufactured and installed by FPI Mechanical Inc, Cohoes, NY. The oil caught in the drip pans is then properly disposed to prevent any environmental impact.

Results. Installing the 54 drip pans saves plant staff considerable time when replacing the gearbox seals, and has averted several gearbox seal failures. In addition to labor cost savings, the drip pans have prevented further environmental impact caused by gearbox oil spills— including costly cleanup efforts and the requisite environmental notifications.

How to validate piping system integrity

Batesville Generating Facility

Owned by LSP Energy LP
Operated by NAES Corp

Challenge. High-density polyethylene (HDPE) piping is commonly used in underground applications because of its relatively easy installation and fabrication process. Moreover, it eliminates the need for either active or passive cathodic protection. Despite these inherent benefits, HDPE fusion joints are not impervious to failure, just as with any other welded joint.

A failed joint at this 837-MW facility resulted in an underground leak of aqueous ammonia that was not immediately evident. The leak was ultimately identified, but not until a significant volume had been lost. The volume and loss rate of the aqueous ammonia exceeded the permissible tons-per-day limit, which ultimately resulted in a fine by the EPA.

The underground leak was not visibly evident as there was neither product percolating to the surface nor any odor even when performing exploratory excavations until the area in the immediate vicinity of the leak was exposed. The failed joint was repaired and a root cause analysis (RCA) process was initiated.

As part of the RCA process it was determined that existing process measurement devices were in place to provide the data points necessary to determine that there was in fact an underground leak. The instrumentation includes one ultrasonic level transmitter on the storage tank and three rotary flow meters providing flow rates to each unit.

Solution. To prevent similar incidents, the site developed control logic that now references the aqueous ammonia tank level and the totalized flow rates of the individual ammonia injection skids at each of the HRSGs. Calculations in the DCS, which allow for ±10% flow rate to accommodate error in the four devices, provides an alarm to the operator if the tank level is depleting at a rate that exceeds that of the totalized flow rate to the SCR systems.

Procedural changes require that the on-call manager be notified immediately to coordinate and approve declaring the unit unavailable and removing the plant from service to minimize the environmental impact. All plant staff has been trained to this programmatic change.

Results. Implementing this logic provides the plant with an ongoing analysis of the process flow to be certain that system integrity is not compromised. The logic change also provides an assurance that a poten-

Batesville Generating Facility

837-MW, gas-fired, three-unit, 1 × 1 combined cycle located in Batesville, Miss

Plant manager: Ken Thorp
Key project participants:
Henry Gainer, operations manager
The entire Batesville staff

tially hazardous substance is not unknowingly being discharged to the environment.

This logic can and should be utilized on all systems that have existing instrumentation capable of providing the necessary data points. In particular, it should be implemented on those systems that can have a deleterious impact on the environment or even on high-cost products to reduce the financial impact of any product leakage.

Implementing this change-monitoring process also was very beneficial as it aided in minimizing the financial penalty imposed by the EPA, which is very pleased with the site's controls modification and the procedural changes that are focused on minimizing any environmental impact.

ISO 14001 certification

Klamath Cogeneration Plant

Iberdrola Renewables

Klamath Cogeneration

500-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Klamath Falls, Ore

Plant manager: Ray Martens

Key project participants:
- Tim Kelly, EH&S engineer
- Greg Dolezal, maintenance manager
- Bruce Willard, operations and engineering manager

Challenge. As part of a worldwide renewable company it was decided that our facility should strive to become ISO 14001 certified and prove that we are diligent at protecting the environment.

ISO 14001 is a voluntary environmental management standard for any company aimed at continually improving its environmental performance, while complying with any applicable legislation. This standard does not dictate how an environmental program should be developed but instead describes the elements that must be included.

Most of our policies and programs were in place, but with the help of a specialized outside contractor we were able to see how each policy and program fit into the standard. It was determined there were several deficiencies that needed correction before we felt an audit would be appropriate.

Solution. The first item to be addressed was the development of an EMS manual. It includes all of the aspects in the facility that could have an impact on the environment—such as stack emissions, bulk chemical control, and water discharges. Each of these aspects undergoes risk assessment and a list of mitigating factors is described. Essentially, this manual is comprised of all of the necessary components demonstrating compliance and conformity to the standard.

Document control was a major issue for us. All of the plant technical manuals had to be gathered into one location and labeled as the control version. All of the plant environmental, health, and safety programs were converted into an un-editable format and placed on a plant-wide intranet site. All documents and manuals outside of these areas are considered uncontrolled and are discarded when no longer needed.

Other areas of effort included the expansion of our training programs to include a greater focus on the environment as well as a continuous improvement plan. This plan creates a requirement to have an incentive for plant personnel to find and implement environmental management improvements. Improvements can be in the form of policy changes or physical system changes that reduce our impact on the environment.

Results. Our audit was conducted in December by a third-party firm certified by ISO. It was a two-day event that scoured through everything relating to the environment from procedures to record keeping. At the conclusion of the audit it was determined that we would be recommended for registration and we received our certification letter later that month.

Our challenge now is to maintain the registration and to meet those continuous improvement goals. Environmental stewardship is extremely important to all plant personnel and we are proud to say that we are meeting the highest standards.

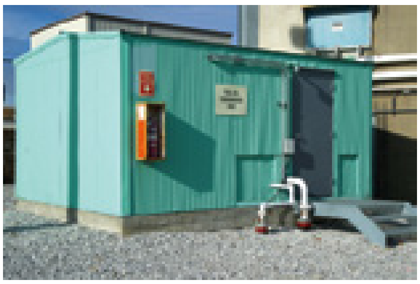
Fuel system upgrade minimizes the possibility of an oil leak

Rokeby Generating Station

Lincoln Electric System

Challenge. The original Rokeby 1 GE 7B combustion turbine was installed as a fuel-oil-fired unit in 1975. Unit 1 was the first of three combustion turbines installed at the Rokeby site. With the installation of Units 2 and 3, their fuel oil systems included double-walled pipe with remotely monitored leak detection.

In 2007, as part of a fuel-oil-storage containment improvement project, the section of fuel-oil lines running from the 2-million-gal stor-



8. Fuel forwarding skid is protected from the elements

age tank to the Unit 1 fuel-forwarding skid was replaced with double-walled, monitored pipe.

This left one section of the unit's fuel-oil system with the original 37-year-old direct-buried piping and fuel-skid components. These fuel system components represented a substandard section in the site's fuel oil system and presented higher risk for a fuel-spill incident.

Solution. In order to reduce the opportunity for an environmental incident, the last portion of the fuel-oil system was upgraded to meet the standards of the rest of the site. The fuel-forwarding skid-upgrade project included the following:

- Replacing the last 20-ft section of underground carbon steel fuel pipe with double-walled, fiberglass pipe equipped with electronic hydrocarbon leak detection
- Adding a fuel-spill containment structure under the fuel-forwarding skid
- Upgrading fuel-skid components, including: replacing every bolt and gasket on all flanged connections; replacing all butterfly valves, relief valves, and associated piping; extending drains for the fuel-oil heaters to the front of the skid for easier access; and rerouting 1-in. return piping through the skid for easier interface with generator piping (Fig 8).

Rokeby Generating Station

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

Plant manager: Bruce Barnhouse

Key project participants:
Dan Dixon, project engineer
Tom Davlin, engineering manager

Results. The decision to replace this last section of the fuel-oil pipe turned out to be more timely than originally envisioned. When the old pipe was excavated for removal it was discovered that a large section of the pipe had not been treated with the OEM's corrosion inhibiting material (allowing it to be in direct contact with the soil since 1975).

The pipe's integrity was still good and no oil was spilled. However, there was some contaminated soil removed from under the fuel forwarding skid when the new containment structure was constructed.

The new section of double-walled pipe was "mapped" into the site's fuel-oil leak-monitoring system, providing 100% coverage for the site's fuel-piping system. The spill containment structure installed for the fuel-forwarding/heating skid allows for storage of up to 2400 gal of fuel oil.

A remotely monitored fuel-oil leak detection system was also installed in the containment structure. The improvements will significantly reduce the risk of a fuel-oil spill caused by failure of a component on the forwarding skid or degradation of buried pipe.

CEMS calibration, gas cylinder tracking critical to compliance

New Covert Generating Facility

Owned by New Covert Generating Company LLC

Operated by NAES Corp

Challenge. Proper O&M of continuous emissions monitoring systems

Daily Cal Gas Bottle Change

What Gas?	CO	L-NOx	H-NOx	(Circle One)
Removed Bottle Info:	S/N:		Exp. Date:	
Installed Bottle Info:	S/N:		Exp. Date:	
New Gas Bottle Concentration:				ppm
Performed By:				
Date:		CEMS Time:		

9. Stamp is used in the CEMS shack log book to ensure repeatability in recorded information, which is audited by management

(CEMS) is critical to environmental compliance. It is of great importance that plant operators maintain up-to-date procedures and processes that include effective inventory control management.

In 2011, the plant team set out to develop a robust program to minimize the risk of human error in CEMS calibration and gas bottle management. The team identified five major areas of program enhancement opportunities as follows:

- Gas bottle inventory tracking
- Bottle changeout procedure
- Calibration and test procedures
- Management oversight and monitoring
- Technician awareness of critical importance of calibration and CEMS maintenance tasks.

New Covert Generating Facility

1100-MW, gas-fired, three-unit, 1 × 1 combined cycle located in Covert, Mich

Plant manager: Rich Evans

Key project participants:
The entire Covert team

Solution:

1. Tag all daily calibration gas bottles to ensure certification date is easily verified during monthly Maintenance Management System (MMS) generated work order that can easily be audited.
2. Develop procedure to require new calibration gas bottles to be labeled/tagged with expiration date when received at the site.
3. Incorporate checklist in the work order with technician's signature and date for daily calibration gas bottle change-out and reporting requirements to ensure task repeatability with log book stamp (Fig 9).
4. Management review of completed work orders to ensure calibration and checks are completed as required (Figs 10-12).
5. Develop tracking sheet with expiration dates for all bottles onsite

Daily Cal Gas Bottle Replacement Work Order

Identify the bottle that needs to be replaced, remove from service and record the following information.
Serial number ______________
Exp Date ______________
PPM value ______________
If bottle is PAST expiration date verbally notify management
Locate replacement bottle verifying expiration dates, PPM Value and type of gas
Install replacement bottle and record.
Serial number ______________
Exp Date ______________
Type of Gas ______________
PPM value ______________
Label new bottle clearly with expiration date: ________ Initials
Enter gas values into CEMS Analyzers.
Verify correct values entered into CEMS Analyzer. ________ Initials
Determine if calibration is required. (check one)
______ NO
______ YES
If YES perform full Stack/SCR analyzer calibration.
Record data from Steps 1 and 3 into CEMS log book.
Complete work order with any comments or concerns and return to management.

Work Order Number ______________

Performed by ______________

Date ______________

10

Failed CEMS Calibration Work Order

Ensure management has been notified that CEMS failed calibration.
Troubleshoot cause of failed calibration.
Troubleshooting results indicate: (check one)
Minor adjustments then recalibrate ______
Minor component (Fuse, thermostat, switch, etc) change out then recalibrate ______
Major component (the whole analyzer) change out required ______
Step C requires that management be notified for direction regarding additional testing (refer to Table 6-1 of QA/QC manual) ______ Initial
After troubleshooting/corrective action taken and recalibration complete:
a. Record all work/action taken in CEMS log ______ Initial
b. Complete work order with any comments or concerns and return to maintenance lead and/or Maintenance Manager.
c. Work Order to be submitted to ops manager for review.

Work Order Number ______________

Performed by ______________

Date ______________

11

CGA Linearity Calibration Work Order

To be performed prior to 168 run hours in quarter

1. Verify calibration certifications dates on all required gases ________ Initial
2. Connect CGA linearity bottles to racks.
3. Enter CGA linearity values into CEMS analyzer.
4. Perform verification of data entry ________ Initials
5. Initiate CEMS linearity test. (NOTE: Best to start 5 minutes after hour to increase instrument reliability percentage.)
6. Verify successful completion of linearity test via data review ________ Initial
7. Remove linearity bottles from service.
8. Place daily calibration bottles back in service.
9. Verify correct daily calibration gas values entered into CEMS ________ Initials
10. Perform manual calibration on CEMS analyzers.
11. Record all work/action taken in CEMS log ________ Initial
12. Complete work order with any comments or concerns and return to maintenance lead and/or maintenance manager.

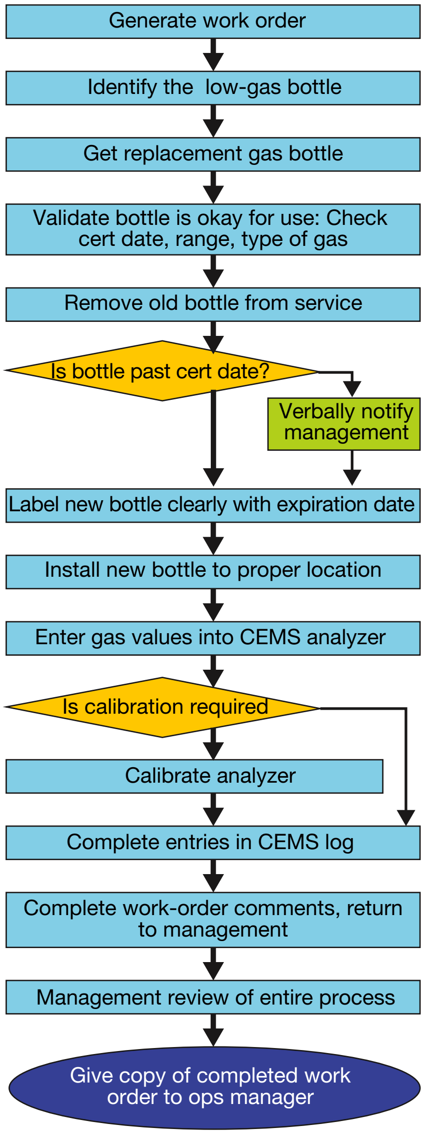
Work Order Number ______________

Performed by ______________

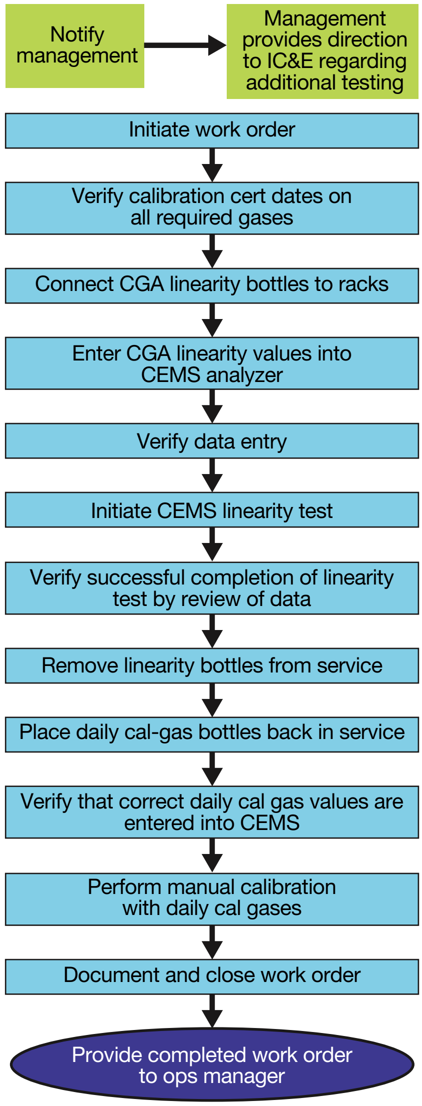
Date ______________

12

10-12. New Covert management uses these three forms to review completed work orders, thereby ensuring that calibration and checks are completed as required



13. Process map for replacement of daily calibration gas. After a bottle has been verified to be greater than three months before its expiration date, it can be installed and used. However it must be monitored closely by management to determine a date for removal from service—for recertification if pressure is adequate, or refill and certification if not



14. Major component replacement process is simple (the one-line, two-step process at top of diagram). Cylinder Gas Audit (CGA) linearity calibration described by the long process flow chart is required quarterly if there are 168 run hours in the quarter. Calibration is required before 168 run hours are accumulated

with management review required by the 15th of each month and a report to the plant manager.

6. Identify continuous emissions data acquisition recording (CEDAR) automation possibilities to minimize risk of human error.
7. Provide training to reinforce recording and notification requirements:
   - Resident bottle time onsite
   - Ramifications of using expired calibration gas
   - Responsibilities in managing abnormal conditions
   - Incident reporting requirements to management.
8. Review of individual CEMS logbooks monthly by operations manager; a technical review is also performed by the maintenance manager; a report to the plant manager is required by the 15th of each month.
9. Process flow charts to be posted in the CEMS shack as a tool for technicians to better understand work flow and what is expected (Figs 13, 14).
10. Review of other procedures and processes to determine generic implications and opportunities to improve.

Results. The findings of the team's process enhancement initiative highlight the importance of maintaining a robust program management system in critical plant processes. Critical programs should include checks, balances, and feedback loops—all of which are designed to drive process improvement.

For Fig 13: After a bottle has been verified to be greater than three months before its expiration date, it can be installed and used, but must be monitored closely by management to determine a date for removal from service to be recertified if pressure is adequate or refilled and certified if not.

Storm-water erosion control project

Dogwood Energy LLC

Owned by Kelson Energy LLC
Operated by NAES Corp

Challenge. After construction of the plant there were two large areas that were used for laydown and parking. These areas were covered with gravel that had large amounts of small fines mixed in with the larger gravel (Fig 15). While this surface is considered as a permeable surface it created sheet flow during rain events that carried the small fines to one of the plants outfalls as suspended solids. The plant had trouble meeting the compliance requirements for total suspended solids (TSS) in its national pollution discharge elimination system (NPDES) permit.

After completing several smaller projects to help lower the TSS levels for several years and even obtaining a sand filter permit from the Dept of Natural Resources, the lowering of permitted levels even further if the sand filter was installed, plus the maintenance aspects of the filter, the plant decided to look at other alternatives.

Solution. The plant decided to take on a storm water erosion control project (SWECP). Instead of filtering the problem, the goal of this undertaking was to just remove the problem. The SWECP required the removal of nine inches of gravel which would then be replaced with nine inches of top soil to grow grass. The soil allows greater

15. Laydown and parking areas were paved with compacted gravel having a high percentage of fines

Year	Outfall
2008	309 mg/l
2009	89 mg/l
2010	79 mg/l
2011	15 mg/l

Dogwood Energy LLC

620-MW, gas-fired, 2 × 1 combined cycle located in Pleasant Hill, Mo

Plant manager: Pete Lepage

Key project participants:
Dwight Beatty, O&M manager
Chuck Berg, plant engineer
Rob Mallett, EH&S coordinator

16, 17. Gravel was removed and replaced with 9 in. of topsoil and seeded. The soil allows greater absorption of water while grass breaks up the sheet flow across the areas that would carry suspended solids to the outfall

absorption while the grass breaks up the sheet flow across the areas that would carry TSS to the outfall (Figs 16, 17).

Results. The plants permit requires <100 mg/l for a daily limit and <50 mg/l for a monthly average. The following results (table) are the yearly averages of the outfall since the current owner has been involved with the plant. The results trend down as different methods of control were attempted. The 2011 outcome represents the time period after grass was established.

Permit poster offers quick access to key numbers

Faribault Energy Park/Minnesota River Station

Owned by Minnesota Municipal Power Agency

Operated by NAES Corp

Faribault Energy Park

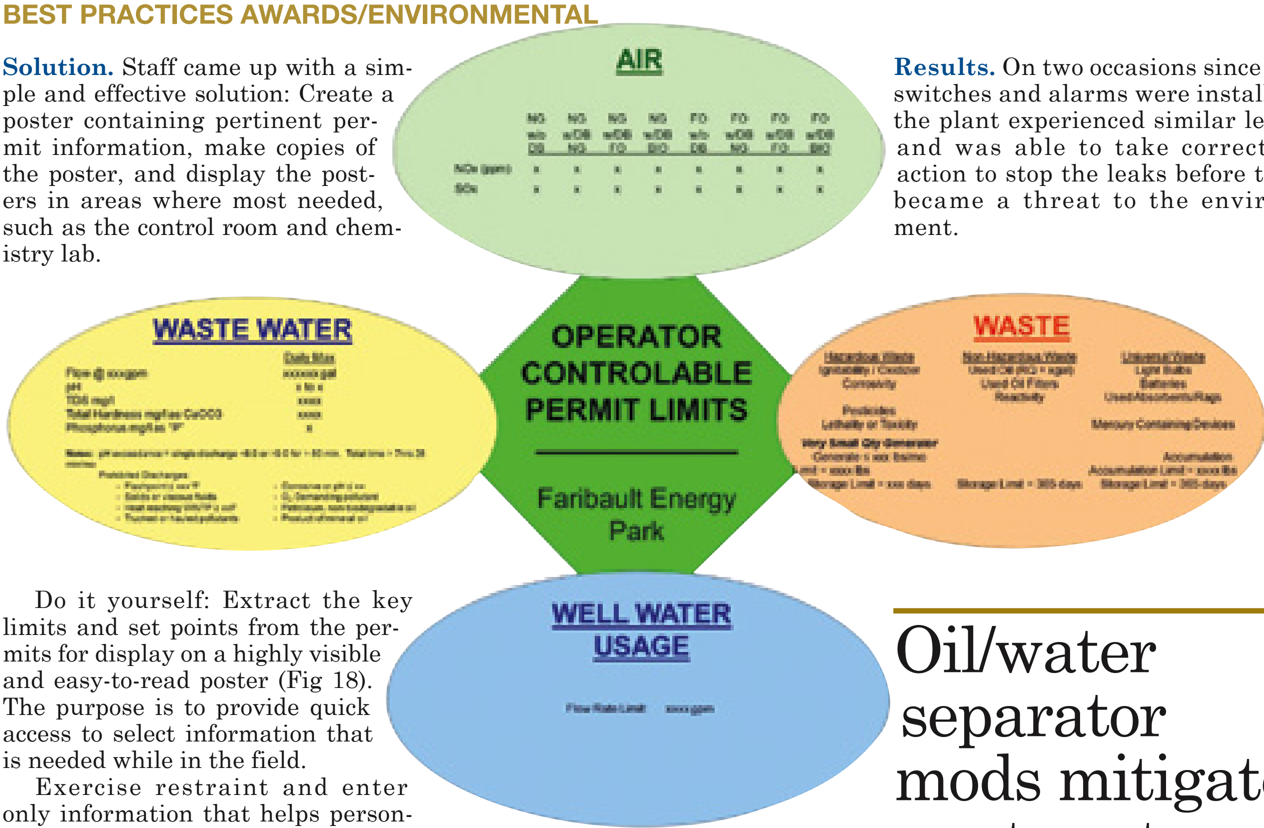
300-MW, gas-fired, 1 × 1 combined-cycle facility located in Faribault, Minn
Minnesota River Station
43-MW, dual-fuel, simple-cycle peaking facility located in Chaska, Minn

Plant manager: Bob Burchfield

Key project participants:
Doug Klar, operations manager
Kevin Wilkins, EHS manager
The entire O&M staff

Challenge. While performing job duties in the field, plant personnel routinely need quick access to just a few key numbers found in the facility air, water, and waste permits. Each of these documents may contain 50 or more pages and can be filled with volumes of information infrequently needed by an operator performing chemistry, or a CRO at the DCS. Routine classroom training doesn't necessarily equip an employee with the sufficient tools and knowledge to remember every key permit limitation or set point.

Solution. Staff came up with a simple and effective solution: Create a poster containing pertinent permit information, make copies of the poster, and display the posters in areas where most needed, such as the control room and chemistry lab.



18. Pertinent permit information is displayed on poster for quick access by personnel

Do it yourself: Extract the key limits and set points from the permits for display on a highly visible and easy-to-read poster (Fig 18). The purpose is to provide quick access to select information that is needed while in the field.

Exercise restraint and enter only information that helps personnel make informed decisions in the course of performing daily routines. Provide technicians with the parameters and information only within their control—listing too much information can "muddy the waters" and may reduce the usefulness of the tool.

Results. The poster serves as a training handout and reduces the chance of violations by empowering staff with the knowledge and numbers they readily need to make informed decisions. Operators and technicians appreciate not having to interrupt a job to locate a number buried in a permit to determine whether the CEMS alarm they just received or chemistry result they just viewed is within the permit limits.

Lube-oil spill alarm effective for timely operator action

Union Power Station

Entegra Power Group LLC

Challenge. The plant had experienced a ruptured lubricating oil line above the GE 7FA lube oil reservoir. It was not discovered by the operators until the oil collected enough to spill onto the ground next to the reservoir.

Solution. The plant staff devised a plan to install a float-type electrical indicating switch that was piped to collect any oil that spilled into the switch body. This would in turn activate an alarm in the GE Mark V controller that would signal the operator in the control room that there was a spill event in progress.

Results. On two occasions since the switches and alarms were installed, the plant experienced similar leaks and was able to take corrective action to stop the leaks before they became a threat to the environment.

Oil/water separator mods mitigate wastewater contamination

Union Power Station

Entegra Power Group LLC

Challenge. On occasion the stormwater flow into the plant's four oil/water separators from ground-level containment areas would exceed the separator's capacity to adequately remove trace amounts of oil draining from nearby plant equipment. The plant's method of oil detection was through weekly effluent sampling of the internal outfall conducted by an offsite laboratory.

Union Power Station

2200-MW, gas-fired, eight-unit, 2 × 1 combined cycle located in El Dorado, Ark.

Plant manager: Tom Burger

Key project participants:
- Bryan Graham, maintenance manager
- Mike Stratton, operations manager
- John Brodnax, plant engineering specialist
- Earl Thomas, plant engineer

Solution. After brainstorming several solutions to the excess oil problem, the staff settled on the idea of placing some kind of restricting orifice in the underground drain lines feeding into the separator inlet.

An on/off control knife gate type control valve was specified to provide this restriction, and a hole was bored into the gate with a diameter that would equate to the design flow limit into the separator. Valves with this modification were installed in the upstream pipe of all four separators.

Results. Since the valves were installed there have been no more significant quantities of oil measured in the associated internal wastewater stream. A further enhancement is in progress to put a manual operator on the valve actuators to open each valve as needed for flushing of the inlet piping if it were to clog with sediment. The plant is better able to take corrective action to stop an oil spill before it drains into the wastewater system.

CO_2 neutralization system makes economic, environmental, safety sense

Termoemcali

Owned by ContourGlobal Latam SA

Operated by NAES Corp

Termoemcali

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

Plant manager: Fabio Ruiz

Key project participants:
Adier Marín, O&M supervisor
Alex Martinez, maintenance planner

Challenge. The demineralized water storage tank receives water from one of two 100% mixed beds. Silica content and conductivity are continuously monitored in the effluent flow and on demineralizer equipment. The total flow to the mixed beds is also monitored.

When throughput reaches 294,000 gal, the regeneration process begins, which uses both sulfuric acid and caustic soda to condition the resin in the bed. All wastewater from the regeneration process then drains into the neutralization sump to initiate the neutralization process.

Government authorities regulate all activities related to the use of sulfuric acid. Any company that uses controlled chemicals in its production processes must request special permission from the authorities for storing and using a specific amount of each chemical. If that amount is exceeded, the authorities can impose severe penalties on the company.

The storage permit for sulfuric acid used at the plant is limited to 24,200 lb/month, enough for only 15 regeneration and neutralization processes. Each regeneration and neutralization process consumes approximately 1650 lb of sulfuric acid. Therefore, the plant requires a truck to deliver sulfuric acid every 15 days, which exposes employees to the many risks of handling this extremely dangerous product.

In addition, any interruption in the production of demineralized water affects plant availability by reducing capacity or stopping the water injection to the combustion turbine for emissions control.

Solution. The plant O&M supervisor had the idea to install CO_2 injection system for the neutralization process to replace the use of sulfuric acid. An inert, colorless, odorless, and nontoxic gas, CO_2 forms carbonic acid in the presence of water and can be used as an acid replacement to neutralize the alkaline discharge stream.

Its numerous advantages make CO_2 an excellent substitute for sulfuric acid, which has been traditionally

1. CO_2 injection system consists of dual four-cylinder manifolds and two injection sites, one on the suction pump and the other in the neutralization tank used in the power industry. Also, CO_2 is produced during industrial processes including the combustion of fossil fuels like coal, oil, and gas, as well as during natural processes—such as the fermentation of liquids and the respiration of plants and animals.

The system, which was installed by a local company, consists of dual four-cylinder manifolds and two injection sites, one on the suction pump and another within the neutralization tank (Fig 1). The system was installed in less than one month and provides several advantages, including:

- Environmentally friendly. Reduces conductivity in discharge saving potential penalties for increased salt content
- Eliminates over-acidification
- Eliminates corrosion issues
- Lowers operating costs. Though similar in price to sulfuric acid, CO_2 reduces indirect O&M costs
- Safer handling. CO_2, which is inert at ambient temperature, saves employees from coming in contact with a corrosive acid that can cause burns and emit toxic fumes
- Ease of use. Equipment operation is very simple
- Possible controlled precipitation of heavy metals or hard components

Results. Sulfuric acid consumption at the plant has decreased by 50%, and the acid now is used only for mixed-bed regeneration. In addition, the plant is more easily able to comply with sulfuric acid use and storage permits without incurring any penalties.

Not only that, plant operations, productivity, and availability are less at risk—losing a permit means interrupting the delivery or storage of adequate quantities of the acid, which in turn reduces the production of demineralized water used for operations. Receiving acid is considered a "high-risk" activity that is now performed only once a month instead of twice a month, thus reducing employee exposure to the acid.

Almost every plant has a radio system; is yours used to full potential?

Ceredo Generating Station

Appalachian Power, a unit of American Electric Power

Challenge. Almost all gas-turbine-based plants have an in-plant, repeater-based radio system for person-to-person communications. Very few plants use the radios to their full potential for operations and personnel safety.

As companies are paying more attention to complying with the National Electric Code's requirements for electrical hazardous classified areas near natural-gas equipment (a/k/a "do not take your cell phone there"), reliance on electrical-hazard-rated radios is increasing.

At generating stations with small staffs there are increasing concerns about personnel working solo or working alone in remote areas of the plant. Lean staffing also presents the situation where the control rooms are not manned 100% of the time and alarms could be missed or not recognized for a significant period of time while plant workers are performing other duties. Plant security and access control also could be an issue that presents itself when operators are away from the control room.

There was a recent situation at a plant performing borescope inspections where no one was in the control room at the time and an oil-tank low-level alarm went off unnoticed by the plant employees working outside. This resulted in 2000 gal of oil being pumped into the generator because of a malfunctioning control valve. Had the alarm been sent through a plant radio system, employees would have been alerted to the low-level situation and they may have been able to reduce the impact of the incident.

Solution, results. Plant personnel at Ceredo have addressed issues outlined above in the following manner:

- All plant radios are rated intrinsically safe for use in natural-gas electrically hazardous areas.
- The radios have a telephone access patch link (through the repeater) and can be used to send

Ceredo Generating Station

505-MW, gas-fired, peaking facility located near Ceredo, WVa

Plant manager: Pat Myers

Key project participants:
Les Adkins, plant supervisor
Pat Flower, O&M tech
Tim Rucker, O&M tech
Rich Tolley, O&M tech

2, 3. "Lone worker" alarm is activated by an employee when working alone (above). If the alarm is not reset an automatic call for assistance is made (right)

4. Alarms are prioritized: A for immediate attention, C for low importance

and receive calls over the landline telephone. Pre-programmed phone number for emergency contacts, operations dispatch, etc, can be assigned so a single button push will perform the dialing. Note that scrambler systems are available on most radios to make conversations private, but they are not used onsite.

- Plant radios have a "lone worker" alarm that is activated by the employee when he/she is working solo at the plant or alone in a remote area of the plant. The radio alarms on a timed basis and the employee must key the mic to reset the alarm (Fig 2).

If alarm is not reset, after a short period of time, the radio transmits a numeric code tone to the repeater where a receiver recognizes the code and then activates an auto dialer that calls for assistance over pre-programmed telephone listings (Fig 3).

- A custom-designed system is hooked to the radio repeater to give verbal announcements over the radio through the repeater concerning three levels of alarm codes. The alarms are sent to the radio interface by relay contact closure from the plant DCS (Fig 4).

Alarms come over the radio verbally as "Code A" for alarms that require immediate attention, "Code B" for turbine control initiated alarm, and "Code C" for alarms of low importance. The alarms continue transmitting on a timed cycle until the alarm is acknowledged in the control room. The highest priority alarm is announced if multiple alarms come in at the same time.

- The plant visitor access system uses a communication scheme based on a modified plant handheld radio where a visitor holds down a switch (which keys the radio) and the visitor speaks into a mic to communicate with a plant employee for access. The plant employee can remotely open the access gate by typing in a code into the key pad of the plant radio (Fig 5).
- A plant radio with a tone receiver module is located in the gate control panel and activates a relay to open the gate. This saves the employee steps to return to the control room (Fig 6).
- Door-open alarms send tones into the radio system to alert the plant personnel when people move through controlled area doors, for security or awareness purposes (Fig 7).
- When working around the combustion turbines, with required hearing protection in place, operators are able to hear radio communications through the use of custom-molded ear plugs with sound tubes. The radio audio reception is clear without being too loud (Fig 8).

5, 6. Plant employees can allow visitors to enter the plant using their radios. A radio with tone receiver module in the gate control panel activates a relay to open the gate

7. Door-open alarms alert plant personnel when people move through controlled-area doors

8. Custom-molded ear protection allows workers to listen to radio communications without damaging hearing

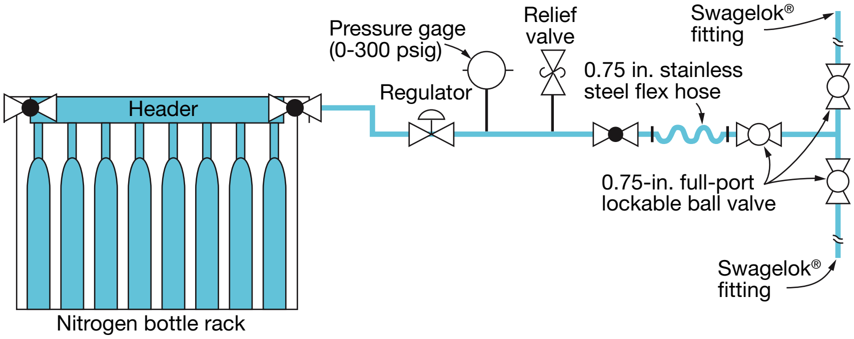
NFPA 56 compliance tooling

Ceredo Generating Station

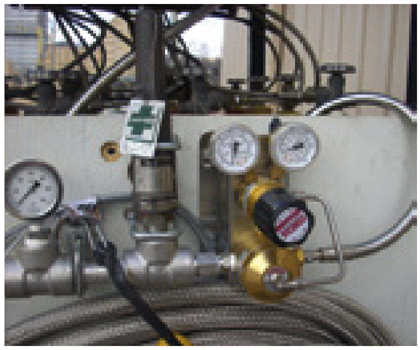
Appalachian Power, a unit of American Electric Power

Challenge. Now that the NFPA 56 O&M requirements are in effect, we must develop efficient and effective methods for compliance. Along with documentation requirements, one of the most difficult tasks is to perform the physical operation of moving large volumes of nitrogen into piping systems in a timely manner to perform pressure swing or sweep purging with nitrogen or another inert gas.

Solution. After numerous arrangement and equipment trials, employees have assembled a nitrogen deliv-



9. System for maintenance purging of natural gas is relatively simple



10. Equipment is stored ready to use on the bottle rack and covered by a boat-top material cover for weather protection (left)

11. All components are assembled on a plywood panel that is clamped to the 16-pack nitrogen bottle rack and is moved from bottle rack to bottle rack when they are changed out (above)

12. Key components in the Fig 9 system are the high-flow dome-type regulator and 0.75-in.-diam, high-pressure, stainless steel piping and hose. Piping is Schedule 80 (left)

13. The bottle rack is moved to where needed by the plant telehandler (above)

ery system that can deliver high volumes of nitrogen in a safe and timely manner. The diagram shows the lay out of the design and the photos show the lay out of the equipment and the use of the system in a maintenance purging operation (Figs 9-13).

Results. The system assembled can pressurize a 65-ft section of 6-in. pipe from 0 to 200 psig in less than two minutes for pressure swing purging. The system can also perform lower-pressure controlled sweep purging at high volume rates.

The relentless drive for performance enhancement

North Pole Expansion Plant

Golden Valley Electric Association Inc

Challenge. Plant engineer Paul Park was developing operating procedures for training purposes when he discovered that a 250-hp backup boiler-feed pump was drawing one-third of its full-load amps while offline. I&E Supervisor Ian Strang and his team of electricians—including Steve Wengelewski, Nate Callis, and Jay Adams—verified that the 480-V, variable-frequency drive (VFD) was drawing 55 amps in motor-off/standby status. Further investigation found that the harmonic filter installed with the VFD was source of that load (Fig 14).

Solution. Plant I&E personnel were challenged to eliminate electrical consumption by the standby pump. Logic drawings provided by the VFD OEM for the drive, inverter, and harmonic-filter installation were studied. A normally open relay installed in the inverter contactor circuit was proposed as a means for de-energizing the harmonic filter in standby operation.

The OEM approved the change and plant I&E personnel performed the relay installation and programming revisions in the plant control system (Fig 15). Now, when a pump start is commanded by the plant control system (PCS), the new relay is closed and powers up the inverter/harmonic filter, a 1-sec timer activates, and the VFD is started. A local bypass was installed around the new relay so the inverter/harmonic filter can be energized in manual if required (Fig 16).

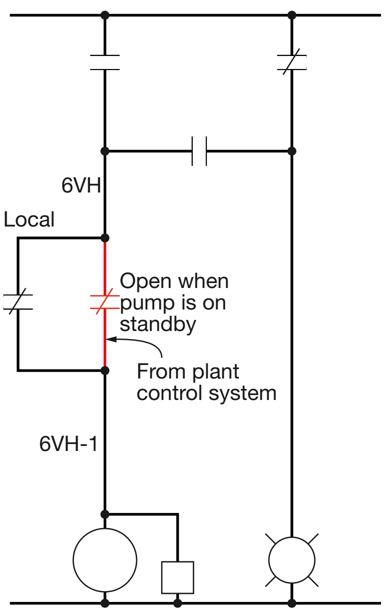
Results. This simple retrofit saves more than 11 MWh/month in plant electrical use and represents an electrical energy saving for the facility of nearly 1%. Total cost of the project was approximately $3000 including parts.

This remote combined cycle burns naphtha from a nearby refinery as its primary fuel, making wasted therms quite expensive. As employ-

ees and co-op members, we are proud of reducing plant energy use by 15 homes worth of power per month with this upgrade.

14. Harmonic filter installed with the VFD for the standby boiler-feed pump was drawing 55 amps in motor-off/standby status (right)

15. Addition of a relay (red) in the inverter contactor circuit was proposed as a means for de-energizing the harmonic filter in standby operation. Relay is open when pump is in standby (below)



16. A local bypass was installed around the new relay to allow manual energizing of the inverter/harmonic filter if required

North Pole Expansion Plant

60-MW naphtha-fired, 1 x 1 combined cycle located in Fairbanks, Alaska

Plant manager: Lynn Thompson

Key project participants:
Ian Strang, I&E supervisor
Steve Wengelewski, electrician
Nate Callis, electrician
Jay Adams, electrician
Paul Park, plant engineer

Small bypass motor yields significant savings, equally effective

Greater Toronto Airports Authority Cogen Complex

Owned by Toronto Pearson Airport

Operated by SNC Lavalin O&M Inc

Challenge. The 2 × 1 LM6000PD-powered combined-cycle cogeneration plant installed by the Greater Toronto Airports Authority in Mississauga, Ont, which began supplying electricity and thermal energy to Toronto Pearson International Airport six years ago, has a capacity factor today of about 20%. When the plant was not running, its 520-hp, 4.16-kV main circulating-water pump remained in service to maintain system water chemistry within specified limits and to inhibit corrosion, biological growth.

Solution. Plant staff saw an opportunity and initiated an economic study that concluded a VFD-equipped, 75-hp bypass pump was sufficient to maintain water chemistry and system condition during the time the plant was not in service (Fig 17).

Results. The bypass pump was installed in June 2011 and the data gathered thus far point to an annual O&M saving of about $225,000. The reduction in electric consumption allowed the plant to qualify for a grant from the local power authority for 50% of the project's cost.

Greater Tronto Airport Authority Cogen Complex

117-MW, gas-fired, 2 × 1 combined cycle located in Mississauga, Ont

Plant manager: John Souther

Key project participants:
- Socrates Furtado, O&M manager
- Craig Rock, energy and utilities manager
- John Thompson, thermal energy and utilities manager
- Jane Lin, senior cogen and utility recoveries manager

Water system improvements cut chemical costs by 10%

Union Power Station

Entegra Power Group LLC

Challenge. The plant obtains its water from a nearby river. The process of conditioning raw water for a 2200-MW combined-cycle facility included several steps—one being the introduction of a small amount of chlorine for biological control. Concerns about the long-term maintainability of this system led the plant staff to evaluate alternatives.

Solution. Working with personnel from GE Water & Process Technologies, Trevose, Pa, it was determined that use of sodium hypochlorite (bleach) as a biological control agent might be more economical and easier to handle than chlorine.

A trial was conducted, and it was found that indeed the hypochlorite achieved the desired result. Permanent construction of a tank and delivery system to the pipeline feeding the raw water treatment plant was completed and the system placed into full time operation.

Results. After the hypochlorite system was installed, the plant steadily

17. VFD-equipped bypass pump maintains water chemistry and system condition at much less cost than the main circ-water pump when plant is on standby

Union Power Station

2200-MW, gas-fired facility with four 2 × 1 combined cycles located in El Dorado, Ark.

Plant manager: Tom Burger

Key project participants:
- Mike Stratton, operations manager
- Bryan Graham, maintenance manager
- Earl Thomas, plant engineer
- Mike Gathright, generation process specialist

Union

reduced chlorine addition to the point it was finally stopped. A further enhancement was needed to achieve small residual chlorine content in the finished water pumped to the powerplant, so a follow-up project was done to install a permanent hypochlorite injection system on it as well.

The water treatment plant has operated over a year now with sustained improvement. Reduction of other chemicals at the water treatment plant was achieved as well as an unexpected side benefit. Overall chemical cost has decreased by over 10%, a significant dollar amount for a facility of this size.

VFDs for cooling-tower fans boost performance, improve safety

McClain Power Plant

Owned by OGE Energy Corp and Oklahoma Municipal Power Authority

Operated by OGE Energy Corp

Challenge. Fans regulate air flow to compensate for changes in ambient air and load conditions. In the past, this was achieved by cycling fans on and off, manipulating fan capacity, or by varying the pitch of fan blades. These methods can have considerable drawbacks and do not leave much room for error.

Solution. Variable frequency drives (VFDs) not only save on energy and increase system efficiency, they perform numerous other functions that eliminate the need for additional equipment. For example, VFDs can sense fan rotation. If a fan is rotating in reverse because of windmilling, a VFD can catch it, slow it down, and ramp it back up in the correct rotation.

However, the primary driver/justification for the plant is to gain the ability to run the fans in reverse and control fan speeds. The ability to reverse fan rotation and control speed makes them beneficial in cold weather. Reversing the fans causes warm air to be blown back into a tower, melting any ice that has formed. These functions are performed using mechanical brakes or reversing contactors.

Since the original design did not have any variable operating capabilities, the cooling tower suffered from excessive icing in sub-freezing temperatures. Operating personnel traditionally have removed the ice manually, but doing so exposes them to injury from falling ice and therefore creates added safety risk.

Across-the-line motor operation would have been efficient had the system been designed for the fans to operate at full speed all the time. However, that rarely is the case at this site. As conditions change (cycling, ambient, etc), air flow needs to change as well. As we cycled our fans on and off, leaving-water temperature fluctuated, thereby contributing to inefficiency, control difficulties, higher motor/gearbox maintenance costs, etc. VFDs are more economical in terms of energy and mechanical cost savings (that is, less wear on the motors, gearboxes, and fans).

McClain Power Plant

520-MW, gas-fired, 2 × 1 combined cycle located in Newcastle, Okla

Plant manager: Matt Schermann

Key project participants:

- Dennis Fairchild, maintenance foreman
- Benjamin Privett, power generation superintendent
- Tony Shook, equipment support superintendent
- Danny Pogue, power supply inspector

McCain

18. MCC modifications were required to accommodate the replacement drives

19. Load-side line reactors for each drive were installed in NEMA 1 enclosures

Results. The plant successfully retrofitted its nine cooling-tower fans in fall 2011. The scope of the project included addition of the following:

- 200-hp Powerflex 755 series drives
- 24-V Powerflex I/O modules
- MCC buckets with modified doors to mount the replacement drives (Fig 18)
- Load-side line reactors sized for application to each drive in a NEMA 1 enclosure (Fig 19)
- Ethernet I/P tap in each drive cell

This project has dramatically improved the cooling-tower motor control performance, motor efficiency, and icing control. A significant risk to plant operators has been eliminated by not having to manually remove ice formations.

Knowing condition of transmitters key to reliable plant operation

Mustang Station

Owned by Golden Spread Electric Co-op

Operated by NAES Corp

Challenge. During winter months, ambient temperatures many times exceed heat-trace capacities on critical gas turbine and HRSG transmitters. Because of the sheer number of transmitters, monitoring of these assets on the DCS can be an overwhelming and time-consuming task. However, such vigilance is necessary simply because the failure of one or more critical transmitters could lead to a plant upset.

Transmitter issues typically occur during critical periods, when generation risk is highest and the need for generation is greatest. A centralized manner of critical transmitter health verification is needed to streamline plant operational reliability and efficiency.

Solution. Using a checklist verification method, a live spreadsheet was set up which illustrates critical transmitters on one screen. This spreadsheet can be viewed on a handy monitor in the control-room operator's (CRO) normal field of view. Each transmitter on the list has a colored indicator button beside its designation. As the spreadsheet acquires live data, it is compared to a set range of limits for each transmitter. If a limit is reached, the indicator button changes color and applicable action commands for the transmitter populate on an information block.

The range of limits for each transmitter is tunable and is set at a lower point than a critical alarm on the DCS. Some of the transmitters monitored include: HP, IP, and LP steam-drum levels; HP, IP, and LP steam pressures; pressure of steam entering the HP, IP, and LP turbines; HP and IP turbine exhaust pressures.

Results. CROs have enthusiastically accepted the live spreadsheet. Specific feedback from the operators included the comment that the live spreadsheet provided a relatively stress-free and quick method of monitoring critical transmitters with the opportunity to take preventive and curative measures prior to plant upsets. This allowed them to operate the plant with greater confi-

Mustang Station

486-MW gas-fired, 2 x 1 combined cycle located in Denver City, Tex

Unit 4: 145-MW gas-fired, simple-cycle facility

Unit 5: 145-MW gas-fired, simple-cycle facility

Plant manager: Bob VanDenburgh

Key project participant: Earl Shoemake, operations supervisor

20, 21. Cold weather is detrimental to reliable and efficient plant operation

Fail-safing water plant operations through color coding

Challenge. The plant experienced failures in the water treatment facility such as clogging of membranes, failure of pipelines, and damage to pumps from loss of net positive suction head (NPSH), etc. These failures, often caused by confusion from poorly marked equipment, came with relatively expensive consequences. Even when the valves were clearly identified and tagged, it was difficult for the field technicians to clearly tell them apart because they were very similar and close to each other.

Solution. With similar equipment in the same area, the confusion caused in indentifying the correct pipelines was prevented with the use of the poka-yoke system. Japanese for fail-safing, poka-yoke helps clearly identify each piece of equipment—panels, valves, pipelines, and auxiliaries—with color-coded banding (Figs 22-25).

Results. After implementing the color-coding system, the failures from

CCC Saltillo

250-MW, gas-fired, 1 × 1 combined cycle located in Saltillo, Coahuila, México

Plant manager: René Villafuerte

Key project participants:
Ricardo Sánchez
Juan Carlos Mares
José Luís Rosales

dence and freed up time to more closely monitor plant safety and efficiency.

Consequently, plant generation and reliability have also improved from the streamlining of cold-weather operations. During the February 2011 severe weather period more than 50 powerplants in Texas went offline from weather-related freeze events (Figs 20, 21).

Our plant remained online the entire time despite experiencing record low temperatures. This early warning system allowed operators to respond to freezing equipment with enough time to implement corrective actions and maintain plant reliability.

this kind of operator confusion have almost been completely eliminated, reducing repair costs, downtime, and equipment damage.

22

23

24

25

22-25. Color-coding system has almost completely eliminated failures in the water treatment plant attributed to operator confusion

Green Country Energy

800-MW, gas-fired, 3 × 1 combined-cycle located in Jenks, Okla

Plant manager: Rick Shackelford

Key project participants:
- Dennis Bradley, operations manager
- Scott Helt, maintenance technician
- Greg Froehling operations tech
- Scott Palmer, I&C technician
- Michael Anderson, I&C tech
- Chris Shipman, I&C tech
- Danny Parish, contracts administrator
- Ron Zane, maintenance manager
- Paul Peterson, director of asset management (J-Power USA)

Plant principles dictate organization of first-rate NERC compliance team

Green Country Energy

Owned by J-Power USA

Operated by NAES Corp

Challenge. The challenge, faced by most IPP projects, is to develop and maintain a comprehensive NERC compliance program, and maintain preparedness for consistently changing standards and interpretations, using existing O&M staff and budget resources.

One of this plant's guiding principles is entitled "The Direction is Perfection," where personnel understand the importance of safety and regulatory compliance and are guided by management in this mission. The challenge was to develop and maintain a new and demanding NERC compliance program without adding additional resources and while being careful not to compromise our guiding principle relating to regulatory compliance.

The development, monitoring, organization, and ongoing maintenance of a comprehensive compliance program are paramount to a solid NERC program. Nevertheless, most IPP projects developed prior to 2006 did not include the resource needs to comply with the new NERC reliability standards within their business models.

Adding plant staff simply to develop and maintain a NERC compliance program would be extremely difficult. Thus only one viable solution was possible: The various new NERC reliability standards requirements had to be fulfilled by the plant's existing resources.

Solution. The first step toward meeting the objective involved selecting individuals from the plant's O&M staff to form an internal compliance team (Fig 1). The team ultimately consisted of the plant manager, operations manager, maintenance manager, contracts administrator, the plant owner's director of asset management, an operations technician, and two I&C technicians.

The internal compliance team typically met weekly to develop and refine the NERC compliance program. The following describes the compliance team's NERC program development steps in simplified terms and in sequential order.

- The internal compliance team first underwent regulatory compliance training, which underscored the importance of reading, understanding, and addressing every single word within the NERC requirements.
- Identified all applicable generator owner and generator operator NERC standards (CIP and 693),

1. GCE's internal compliance team: Rick Shackelford, Danny Parish, Dennis Bradley, Ron Zane, Mike Anderson, Chris Shipman (from left). Camera shy: Scott Helt, Scott Palmer, Paul Peterson as well as all applicable GO and GOP requirements.

- Reviewed the applicable reliability standards audit worksheets to gain insight related to auditor expectations.
- Participated in regional NERC workshops on an ongoing basis (one or two team members consistently attended the workshops two times per year).
- Identified pre-existing O&M processes and procedures that supported NERC expectations.
- Developed new and additional O&M procedures, processes, and personnel training needed to assure and demonstrate compliance.
- Developed an extensive data base system to tie O&M processes and procedures to the appropriate NERC standards, and vice versa.
- Engaged in preparing the six-year audit package, including compiling and organizing a great deal of necessary supporting documentation.
- A gap analysis of our audit package was performed by a consultant.
- Made improvements to the audit package to address consultant concerns.
- Led by a corporate compliance manager, the internal compliance team underwent regulatory audit training prior to the audit.

One of the most crucial elements related to developing and maintaining a good compliance program involves selecting the right individual to move the process in the right direction. An operations technician was ultimately selected and he performed exceptionally.

In addition to leading many of the above described activities, he also engaged in:

- Scheduling and facilitating the weekly meetings
- Monitoring NERC and SPP websites for hints, suggestions, and answers to team questions
- Participating in various NERC and SPP workshops and webinars
- Coordinating the compliance efforts with the plant owners and a NERC consultant
- Developing a database (including a navigation process) to store documentation and to produce the audit package.

Results. This plant's commitment to a comprehensive NERC program paid off with very successful 2011 audit results in July and August. There were "no findings" declared by the auditors, following very thorough six-year CIP and 693 NERC compliance audits.

The success was attributed to a team effort with the entire plant staff involved in the process in one way or another. It is now believed that we have the right processes in place to ensure a flexible, sustainable, and maintainable NERC compliance program going forward.

The plant's audit experience was so positive that the NERC regional authority invited an internal compliance team member to share about our audit preparation processes, lessons learned, and resulting successes at a regional workshop last October.

Active performance monitoring of HRSGs

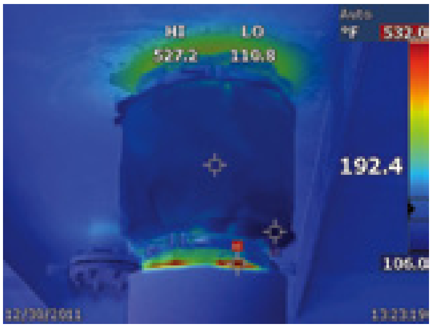
Osprey Energy Center

Calpine Corp

Challenge. As plants age, small performance losses can be missed or accepted.

Solution. Through routine monitoring and spot checks of HRSG and steam-piping condition, users can locate issues and "nip them in the bud." On a routine basis plant personnel review thermal and ultrasonic data to stay abreast of performance-related issues and remediate at the most opportune times.

> **Osprey Energy Center**
>
> 600-MW, gas-fired, 2 × 1 combined cycle located in Auburndale, Fla
>
> **Plant manager:** Steven Smith
>
> **Key project participants:**
> Andrew Martin, plant engineer
> Gil Kaelin, maintenance manager



2. IR image shows HRSG lower penetration seal is in good condition

Thermal imaging of the HRSG on a panel-by-panel basis helps locate hot spots or increases in temperature profiles (Fig 2). This, combined with a periodic individual check of HRSG upper and lower penetration seals, allows for early identification of insulation losses and/or seal clamping effectiveness.

Adjustments of penetration seals can reduce the likelihood of early failures and decrease operating costs.

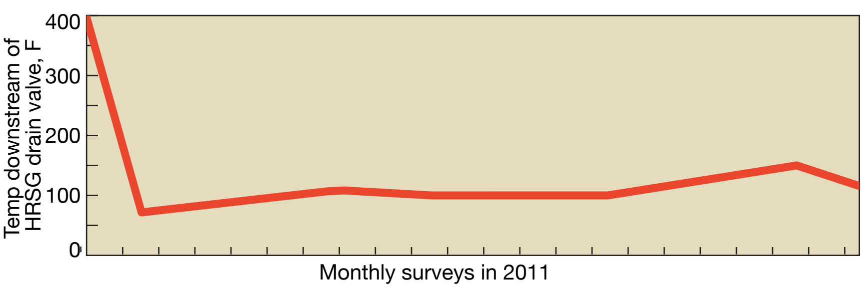
Site personnel have been trained in adjusting penetration seals by the OEM and installer, increasing the level of ownership and participation.

Select areas of boiler feedwater piping have had inspection ports added to allow ultrasonic testing (UT) of wall thickness to monitor for FAC (Fig 3). During outages, HRSG tube bends are surveyed. Early FAC detection is key for piping replacements to be scheduled and planned in an effective manner or, ideally, prevented altogether. Thickness testing is one of the ASME B31.1 Chapter VII recommendations for condition assessment of covered piping systems.

Resistance temperature detectors (RTDs) were installed on the downstream side of HRSG drain-valve outlet piping to monitor valve seating effectiveness (Fig 4). Questionable valve leaks by can be verified using ultrasonic emission testing. This monitoring program of the drain valves allows for early detection and improved pre-outage planning.

Results. By keeping tight control of heat within the system, the facility keeps its heat rate low and marketability high. By way of comparison, 2011 heat rate bested the 2005 heat rate with a lower forced-outage rate.

3. Elbow in boiler-feed pipe is UT-checked for wall thickness



4. Temperature of HRSG drain confirms drain valve is properly seated

Generator control system mods ensure NERC compliance

Tenaska Central Alabama Generating Station

Tenaska Alabama II Partners LP

Challenge. There are several requirements in the North American Electric Reliability Corp (NERC) Reliability Standards that address automatic voltage regulator (AVR) and power system stabilizer (PSS) operation and maintenance.

For example, the status or capability change of any reactive power resource, including AVRs and PSSs, must be reported to the electric transmission operator within 30 minutes. Several generator owners have self-reported possible NERC violations because their generators were inadvertently operated with the AVR in the wrong operating mode or with the PSS disabled, especially following scheduled plant outages.

Solution. The turbine/generator control system logic and operator interface graphics were modified to ensure compliance with the NERC requirements for AVR and PSS operation prior to unit startup. Start permissives were added that require the PSS to be enabled before a unit start can be initiated.

In addition, pop-up windows with warnings and reminders were added to the control system display, including a reminder that the electric transmission operator and plant manager must be notified before the AVR can be taken out of automatic voltage control operating mode.

Results. The generators are only operated in automatic voltage control and the PSSs are never disabled. These modifications to the turbine/generator control system logic and operator interface graphics ensure continuous compliance with the NERC requirements for AVR and PSS operation.

Tenaska Central Alabama Generating Station

885-MW, gas-fired, 3 x 1 combined cycle located in Billingsley, Ala

Plant manager: Robert Threlkeld

Key project participants:
- Cecil Boatwright, operations manager
- David Wilroy, maintenance manager
- Brian Pillittere, plant engineer

Efficient outages with traveling steam-turbine warehouse

Plants Franklin, Harris, Stanton, and Wansley

Southern Co

Challenge. Our fleet has four combined-cycle plants with Alstom steam turbine/ generators, which are located in the three bordering states of Alabama, Florida, and Georgia. The Alstom fleet has specialty tools and parts required to support these units. In tools alone, there are several hundred tools that are not readily available to buy off the shelf.

The challenge was finding the documentation and having the right tools and parts whenever the units were in outages, planned or forced. Plant staff had the difficult task of identifying all of the specialty tools and parts needed. Once identified, we encountered lead times of up to 18 months some parts/tools. In order to avoid extending outages, we needed a system in place that supported the outage execution efficiently with limited manpower.

Solution. Our team worked together to develop a steam-turbine "traveling warehouse" of equipment necessary in maintaining the Alstom steam turbines (Figs 5, 6). The traveling warehouse consists of four specially designed Conex trailers housing specialty tools, parts, and equipment, which can be easily moved from plant-to-plant as necessary to support fleet turbine outages.

Plant Franklin

1806-MW, gas-fired, three-unit 2 × 1 combined-cycle located in Smiths, Ala

Plant Harris

1254-MW, gas-fired, two-unit 2 × 1 combined-cycle located in Autaugaville, Ala

Plant Wansley

1180-MW, gas-fired, two-unit 2 × 1 combined-cycle located in Heard County, Ga

Stanton Energy Center

656-MW, dual-fuel, 2 × 1 combined-cycle located near Orlando, Fla

Key project participants:
Ian Brown, Brian Castronova, Dave English, Dusty Mathews, Sid Mimes, Ed Ryan, and Patrick Walker

Results. Having access to the right tools and parts increases manpower efficiency and unit downtime while eliminating the risk being unable to support outage need. An additional of benefit is increased outage safety. Using the right tool for the right application is now easily achieved since the tools are now readily inventoried and available.

5, 6. Four trailers stock specialty tools, parts, and equipment to facility deployment to plants with Alstom steam turbine/ generators as required

NERC VAR-002 R3 notification aids

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

Challenge. Notification of a status or capability change on any generator reactive power resource, including the status of each automatic voltage regulator (AVR) and power system stabilizer (PSS), and the expected duration of the change in status or capability, must be made as soon as practical, but within 30 minutes, as required by North American Electric Reliability Corp (NERC) VAR-002 R3.

Solution. We added logic to the distributed control system (DCS), the turbine controller, and OSIsoft Plant Information (PI) notifications to remind the operator of

Tenaska Virginia Generating Station

885-MW, gas-fired, 3 × 1 combined cycle located in Scottsville, Va

Plant manager: Robert Mayfield

Key project participants:
Jay Hoffman, plant engineer

this requirement and to alert plant management of this status change. Here's how:

1. The turbine controller computer now has a pop-up window reminding the operator, when either the power system stabilizer (PSS) or automatic voltage regulator (AVR) status is manually changed, of the required report, the 30-min time limit, and the easy-to-miss expected duration of that change.
2. The DCS now has multiple alarms for the PSS:
   - If the status changes, an alarm reminds the operator of the required report. Because of system text limitations this is a shortened version of the pop-up window text.
     This alarm remains active for one hour.
   - If the PSS is disabled, "PSS disabled: 30 min report to top" alarm comes active and remains locked on the screen as this is an abnormal condition.
   - Every day at 8 a.m., the alarm re-annunciates to remind the operators of this abnormal condition.
3. "PSS enabled" was added as a start permissive since this is the preferred mode of operation. The plant's exciter defaults to "PSS disabled" when powered on. This will prevent missing reports when the plant comes back online following an outage.
4. The PI notifications feature was activated to send email notifications to key management personnel any time the PSS or AVR changed status. This is a backup to the operator as it contains text similar to the pop-up window.

Results. We have successfully minimized the chance that this NERC-required report can be missed or is lacking the full detail required.

CO_2 tube blasting of HRSGs improves heat rate

Hopewell Cogeneration Facility

IPR-GDF Suez Energy North America

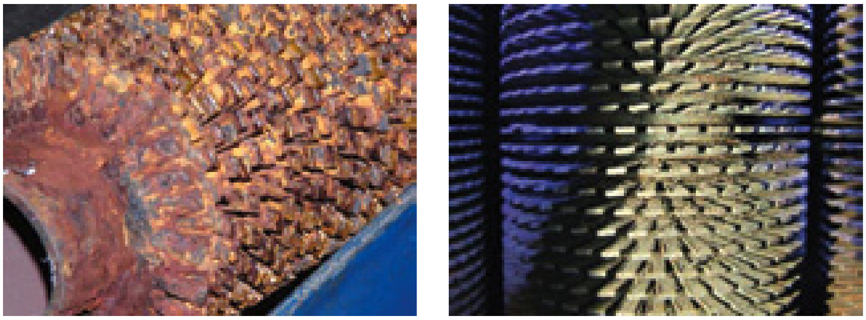
Challenge. The plant was commissioned August 1990 and degradation of heat rate became a major concern to plant staff over time. The idea behind CO_2 blasting or any other

Hopewell Cogeneration Facility

365-MW, gas-fired, 3 × 1 combined-cycle cogeneration facility located in Hopewell, Va

Plant manager: Bob Greene

Key project participants:
Jamie Dalton, mechanic
Steve Henry, maintenance supervisor
Chuck Barnes, plant engineer
Entire Hopewell staff



7, 8. HRSG tube condition before (left) and after (right) CO_2 blasting

type of cleaning of HRSG tubes is to remove rust and deposits, thereby increasing heat transfer. This increase in heat transfer will show up in the plant as an increase in performance in the form of better heat rate.

Solution. HRSG CO_2 blasting was carried out in spring 2011. All three HRSGs at the site were cleaned. The material removed by blasting is blown down to the floor of the HRSG and vacuumed up, placed in a container, and recycled. In this way there is nothing left when the job is complete except clean tubes (Figs 7, 8).

Results. This was the first time the tubes were cleaned and the results were dramatic; heat rate improved by 176 Btu/kWh. Based on the price of gas at the time of the cleaning, $5/million Btu, the cost of CO_2 blasting (a nominal $150,000 for all three units) was recouped in only two months of summertime operation, suggesting that the HRSGs probably should have been cleaned sooner.

This prompted personnel to develop a calculator, which indicates an economically beneficial time to clean the HRSGs. Note that this calculator only considers the economic benefit of heat-rate reduction. If plant operations are impacted by emissions limits (for example, mandated load reduction, purchase of emissions credits, etc) that cost impact also should be factored into the decision to clean tubes.

Assumptions used in developing the plant's CO_2 blast calculator were these:

- Blasting will restore at least 90% of lost heat rate
- "Timeframe selected"—one year, for example—is the interval between cleaning
- Project an average cost of fuel over the timeframe selected
- Project an average value for electric production over the timeframe selected
- Use a budget type bid to get cost of CO_2 blasting and clean-up
- Degradation is a curve, but for calculating the need for cleaning make the degradation linear to estimate degradation over the years since cleaning or commissioning and project the same rate
- Cost of cleaning should reduce the heat rate enough to pay for the cleaning in the timeframe selected—such as one year.

Here is the formula developed by the Hopewell staff:

$0.9HR_d \times FC \times 1000$ kW/MW $\times MW_y = CC$

Where: HR_d is heat-rate degradation in Btu/kWh; FC is cost of fuel in $/million Btu; MW_y is annual (or other timeframe selected) electric production in MWh; and CC is the cost of CO_2 blasting in $.

Permanent RO system with UF a win-win

Faribault Energy Park/Minnesota River Station

Owned by Minnesota Municipal Power Agency

Operated by NAES Corp

Challenge. Soon after accepting care, custody, and control of a newly constructed GE 7FA combined-cycle facility in fall 2007, plant staff faced freeze-related challenges, including the initial water treatment set-up shown in Fig 1. The facility was using rental trailers equipped with demineralizers for water treatment and they were exposed to ambient conditions.

During winter months, these trailers and ancillary equipment were susceptible to freezing and had the potential to impact plant availability. Processes also associated with these trailers led to the formation of a potential slip hazard from ice around the trailer. Plant staff, together with the owner, wanted to develop an economic solution to this demineralizer set-up.

Solution. Plant O&M staff, led by operations manager Doug Klar and a third-party service provider (on behalf of owner), decided a first priority was to plan and construct a building over the plant's mixed-bed rental trailer to prevent freezing, eliminate the slip hazards associated with ice around the trailer, and increase plant reliability.

Even though the plant's discharge contract prohibited both reverse

1. Cold weather adversely impacted the operation of trailer-mounted mixed-bed demineralizers and created safety issues

2. An ultrafiltration/RO system provides makeup both for the cooling tower and mixed-bed demineralizers

Faribault Energy Park

300-MW, gas-fired, 1 × 1 combined-cycle facility located in Faribault, Minn

Plant manager: Bob Burchfield

Key project participants:
Doug Klar, operations manager
The entire O&M staff

osmosis (RO) and softener waste streams, the operator and owner decided to optimistically design a building with enough room to accommodate a future permanent water treatment system.

In parallel with building construction in 2009, the site successfully negotiated a discharge contract language change that allowed discharge of RO reject water, providing the waste stream impact was first approved by the city.

A year and a half later, when funds were approved for a permanent water treatment train, the impact study prepared by the operator was presented to the city and the proposed equipment was subsequently approved.

In the development phase that followed, plant personnel prepared a detailed RFP, reviewed multiple bids, and negotiated with at least six prospective water treatment OEMs. This extensive research and bidding process provided plant staff the opportunity to learn much about the advantages and disadvantages of available water treatment technologies.

Throughout the design review phase, we frequently updated the owner with the pros, cons, and costs associated with each technology. The operator prepared and presented a return-on-investment (ROI) analysis to demonstrate the benefits of an integrated RO system as a cost-effective way to replace the trailer rentals while providing other inherent water quality improvements.

After extensive review, the owner and operator agreed to pre-treat the RO with an ultra-filtration (UF) unit rather than adding a second multimedia filter (MMF). While ultrafiltration is more expensive than MMF technology, it provided superior pretreatment protection for the RO. UF can filter particulate matter down to 0.1 micron as compared to MMF's 20-micron capability. The UF was installed downstream of an existing MMF that continues to provide "whole plant" filtration for both the cooling tower and demineralizer plant.

An appropriately sized rental mixed-bed bottle was chosen to polish the RO product water, eliminating the need for the customary acid and caustic tanks required for regenerating a permanently installed mixed-bed vessel. An electrodeionization (EDI) unit was ruled out because of its higher capital and maintenance costs and the limited electric service available to the RO building.

Plant personnel voluntarily took on the scope of work to design, procure, and install all interconnecting piping, valves, instrumentation, plant air, and DCS screens, resulting in additional savings. New electrical feeder breakers and wiring were subcontracted to a qualified third party to ensure relay coordination was not adversely impacted by the additional load.

Results. The dry, climate-controlled building with an ultrafiltration/RO system was commissioned (Fig 2). Slip hazards are reduced and the plant has a higher quality demineralized water supply than before. The RO reject stream goes to the cooling tower and is cycled through until blowdown or evaporation.

Most people gain a great deal of satisfaction when we create and build. Not only did we save monetarily by taking on those portions of the project we were qualified to perform, the team built a sense of ownership that manifested into O&M excellence and owner satisfaction.

Engineered solution improves SCR performance

Granite Ridge Energy

Owned by Granite Ridge Energy LLC

Operated by NAES Corp

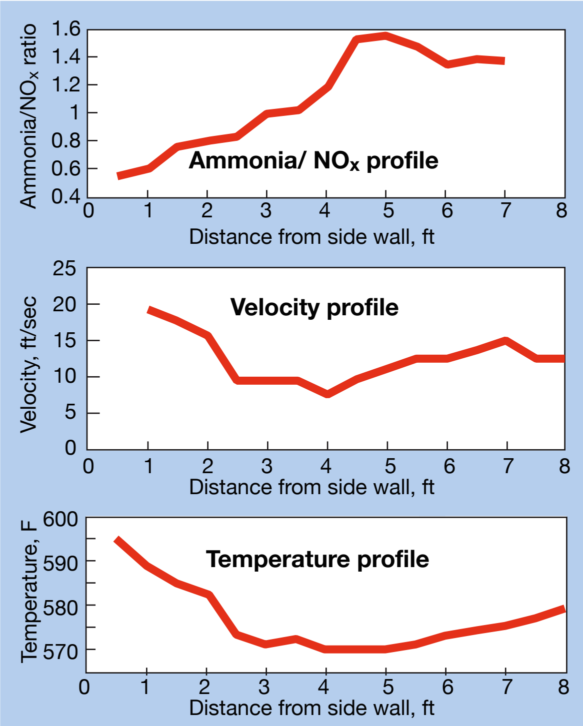
Challenge. The problem, as described by industry veterans Jim Carlton, president, and Larry Hawk, plant engineer, Granite Ridge Energy, operated by NAES Corp, was that the plant had been challenged by an underperforming NO_x catalyst since commissioning. However, routine destructive sampling of the catalyst showed reactivity at or above expectations. And testing confirmed that the ammonia injection grid was properly balanced. What to do? The plant set out to determine the cause and correct the issue.

Granite Ridge Energy

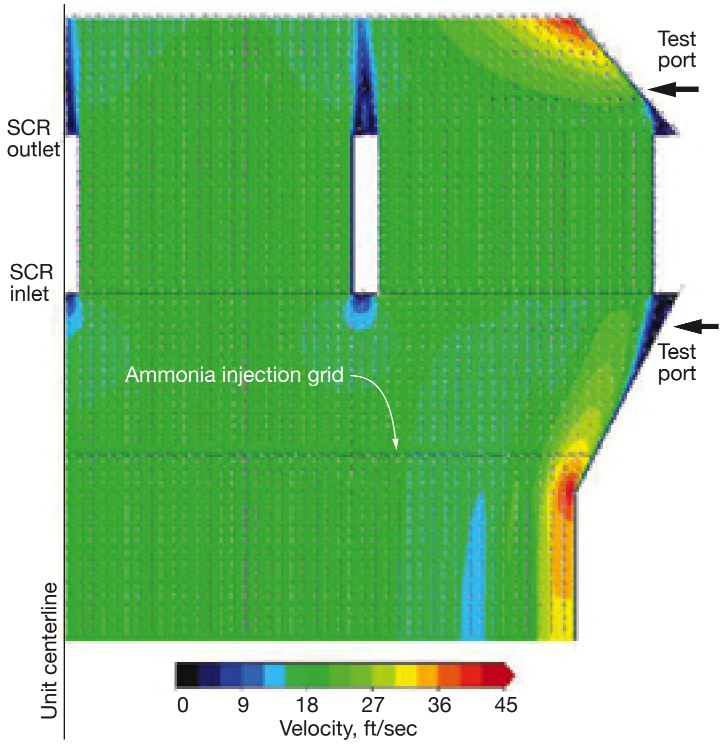
730-MW, gas-fired, two-unit, 1 × 1 combined cycle located in Londonderry, NH

Plant manager: William Vogel

Key project participants:
Jim Carlton, president
Larry Hawk, plant engineer



3. Data collection was the first step in developing a solution for the underperforming NO_x catalyst



4. CFD model (plan view) was created to help evaluate alternative solutions

Solution. GRE contracted the SCR OEM and an emissions testing company to conduct an online evaluation of the catalyst grid. Measurements of ammonia-to-NO_x ratio, flue-gas velocity, and gas temperature were made upstream and downstream of the grid and at different distances from the side walls (Fig 3). Data collected revealed the following:

- The ammonia/NO_x ratio ranged from about 0.5 to 1.6, lowest near the side wall and highest at 5 ft from the wall.
- Gas velocity ranged from 7.5 to 20 ft/sec, highest closest to the side wall and lowest about 4 ft from the wall.
- Temperature ranged from 570F to 595F, again highest close to the side wall and lowest at about 4 ft from the wall.

Solution. The OEM's engineer created a model (Fig 4) to help determine the best path forward to correction, and a two-phase implementation plan was created. The first step was to increase the as-designed catalyst to support steel baffling and thereby prevent gas from bypassing the catalyst grid (Fig 5).

This relatively low-cost activity was implemented in one of the plant's two heat-recovery steam generators (HRSGs) in 2010, during a planned outage. Performance gain proved negligible.

The second step was to erect a perforated-plate baffle immediately upstream of the ammonia grid on each side of the HRSG (Fig 6). The 80-ft-tall × 3-ft-wide baffle was designed to have a local restriction of 40% but negligible effect on backpressure. The goal was to slow down exhaust-gas velocity at the side walls to allow proper catalytic conversion. Both HRSGs were equipped with the baffles, supplied by Vogt Power International Inc, Louisville, during the facility's most recent planned fall outage.

5. Steel baffles were installed to prevent exhaust gas from bypassing around the catalyst grid

6. Perforated flow restrictor reduces exhaust-gas velocity close to the side wall, with minimal impact on backpressure

Results. Worked! The baffles' control of flow characteristics immediately upstream of the SCR enabled an approximate 13% improvement in the ammonia/NO_x ratio. Result: The facility is able to operate as intended with efficient control over it ammonia usage. CCJ

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, Chattanooga, selected from its ranks a panel of seven judges for 2012. 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:

- Three judges are plant managers.
- Four judges are located at 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 GT-based generating facilities; several have conventional steam-plant experience as well.
- One judge is expert in aero engine O&M, the others specialize in frames.
- Plant management/operations experience of the panel is well over 150 years.

Each judge received a notebook containing the entries arranged by category: Environmental Stewardship, Safety (two categories: Procedures & Administration and Equipment & Systems), Design, and Operations and Maintenance (two categories: O&M Business and O&M Balance of Plant); plus, a score sheet. The assignment: Read each entry for a given category and rate it from 1 to 10 for the five evaluation parameters listed below. 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. Entry with the lowest point total in a given category is awarded a "1," next highest a "2," and so on. Each judge submits his or her rankings to the editors, who then add them. Lowest point total in each of the eight categories is rated The Best of the Best.

This year the voting was tight, but there were no ties. A total of six Best of the Best plaques will be awarded in 2012. CCJ

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 2013 Best Practices Awards program (instructions at www.ccj-online.com/best-practices.

To better gauge how your entries might be rated, consider evaluating the 2012 entries and see how the results compare with those of the judges. The score sheet below is helpful in this regard.

Category/ Submittal		Business value Score × Wt +	Complexity Score × Wt +	Staff involvement Score × Wt +	External coordination Score × Wt +	Duration of value Score × Wt =	Total score	Rank
Management	1	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Management	2	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Management	N	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Environmental	1	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Environmental	2	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Environmental	N	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Safety	1	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Safety	2	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
Safety	N	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
O&M	1	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
O&M	2	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		
O&M	N	× 10 +	× 8 +	× 6 +	× 5 +	× 9 =		

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Western Turbine XXII exceeds expectations

The 2012 edition of the world's largest conference and exhibition for owner/operators of GE LM (land and marine) aeroderivative gas turbines, sponsored by the independent Western Turbine Users Inc, was held at the Pasadena (Calif) Convention Center, March 18-21. The 23rd annual meeting will be conducted at the San Diego Convention Center, March 10-13, 2013.

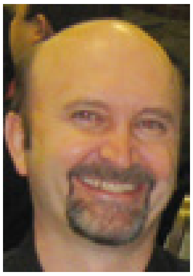
In terms of size, this was the second or third largest meeting in the all-volunteer user group's history. With attendance approaching 900 as the conference started, second place was a possibility. More than 1200 persons attended the 20th anniversary meeting in San Diego two years ago. On the exhibit floor, 146 companies were represented—the second most ever.

The Western Turbine conference is dominated by breakout sessions focusing on O&M issues for each of the gas turbines supported: LM2500, LM5000, LM6000, LMS100. There also are multiple tracks featuring presentations in special interest areas, as well as presentations of a general nature. Social events and meals round out the program.

This article covers topics from the Pasadena meeting of general interest to the LM community, and in some cases, owner/operators of other types of engines as well. Technical details are reserved for a special report in 3Q/2012 covering the specifics of the four engines.

Ramping up

President Jon Kimble of California-based Wellhead Electric Co started the meeting by reminding attendees why they were in Pasadena. The aero sector of the electric power industry is in a continual state of technical change, he said. Proof includes that in the last year, the OEM had issued more than 30 service bulletins for each of the LM6000 and LMS fleets. Keeping up with the issues and engine enhancements to maintain top performance is vital to all companies engaged in the competitive generation business.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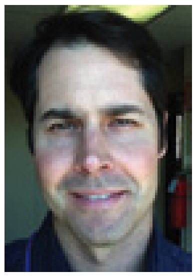

Gundershaug

Business matters were next. Kimble announced that Don Haines, who manages the Panoche Energy Center for O&M contractor Wood Group Power Plant Solutions, had completed his three-year term on the Board of Directors and was being succeeded by Calpine Corp's Andrew Gundershaug. Haines continues as chairman of the LMS100 group within WTUI; Gundershaug is the LM5000 chair.

Also, Bryan Atkisson, recently appointed a plant manager by Riverside Public Utilities, retired as chairman of the LM6000 breakout after five years at the helm, following the meeting. David Merritt of Kings River Conservation District, a member of the board of directors, replaced Atkisson.

The depots

The success of the Western Turbine meeting is underpinned by the technical and financial support of the five depots licensed by the OEM to inspect and repair the four engines addressed by the group: Trans-Canada Turbines (TCT), Calgary; MTU Maintenance Berlin-Brandenburg GmbH, Ludwigsfelde, Germany; Air New Zealand Gas Turbines (ANZ), 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, most related to new repair facilities:

IHI Executive Officer Hiroyuki Otani reiterated President/CEO Kazuaki Kama's commitment to world-class support of US LM6000 users despite the challenges of the Fuku-

shima disaster which impacted production at one of the company's shops for a couple of months. Since that time, IHI has expanded and improved the efficiency of its Mizuho and Kure No. 2 Works. It has also opened a Level 2 shop in Cheyenne with Wyoming-based Reed Services Inc.

TCT's presentation by Darcy Simcinelli, director of customer support, and Dale Goehring, director of customer support and GE projects, focused on the company's overhaul and repair facilities and capabilities for the LM6000 and LM2500 fleets. Most impressive of its shops is the 225,000-ft^2 Airdrie plant about 20 minutes north of Calgary by car. It features an automated clean line, 21 overhead cranes, nine balancing machines, space for component repair in the future, and truck bays to facilitate loading and unloading.

Other service facilities in the company's portfolio, most opened within the last few years: Houston, Bakersfield, Syracuse, Cumbernauld (UK), Singapore, and Perth (Australia). These range in size from about 4000 to 15,000 ft^2 and were referred to as "hospital shops" for small jobs. Next facility to open (before July) will be an LM6000 test facility being installed alongside the company's existing test cell.

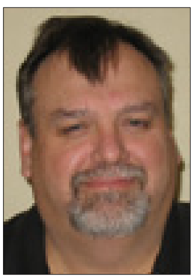
MTU's Ludwigsfelde facility is the company's center of excellence for the repair of industrial gas turbines. It is equipped to inspect and repair all types of GE LM2500/5000/6000 engines. This lead facility works closely with company shops in Hannover and Munich, Germany, and in Kuala Lumpur—and most recently the New Braunfels (Tex) plant, which opened in 2010, and a Level 2 facility in Thailand, which opened in June 2011. Yet another shop is planned for Brazil.

Avio reviewed the inspection and repair capabilities of its Turin and Brindisi facilities and announced that a new division, AvioService, was established in July 2011.

ANZGT reported that it had invested significant resources in the last year to develop a field service office in Bakersfield, Calif, and a global field service team. Western Turbine veterans Frank Oldread and Jimmie Wooten, former directors of the user group, were introduced as the general manager and field service supervisor, respectively, for the Bakersfield facility.


Oldread


Wooten


Baker

The company's depot, based at Auckland International Airport, provides full Level 4 overhaul capability, module exchanges, engine testing, failure analysis and investigation, and in-house repairs for LM2500 and LM5000 engines. ANZGT also manages critical LM5000 parts for the OEM.

Breakout overview

A common thread running through the LM2500, LM5000, LM6000, and LMS100 breakout sessions during the two-and-a-half-day meeting was that current issues typically were carryovers from previous meetings; relatively few new problems were reported. However, that the issues were not "new" did not detract from the level of interest, primarily because of the high percentage of first-timers. In fact, a couple of the breakout sessions ran half an hour beyond the official 5 p. m. closing bell on the first day of the meeting.

LM2500. John Baker, the plant manager for a 1 × 1 LM2500-powered combined cycle owned by Riverside Public Utilities, chaired this breakout with help from the OEM and representatives of TCT, ANZGT, Avio, and MTU for all but the user-only sessions.

The depots reported seeing many issues in the last year that had been addressed previously. They were of the general opinion the repeat problems were being experienced because users were not proactively accessing and reading service bulletins and letters, product bulletins, and OEM manuals posted on the GE customer website.

Recall that the OEM now delivers documentation for its customers via the Web. Users are responsible for retrieving this information and using it to guide plant operation, inspection, and maintenance activities. The benefit of keeping current on GE bulletins and advisories, it was said, saves users money in the long run. It was also mentioned that all owners get an updated O&M manual annually from GE and that it's important to use the latest version of that material. If you don't know who in your organization receives the CD from the OEM, contact your customer service rep.

Here's a run-down on some of the specific engine-related technical issues that were addressed during nine hours of total breakout time. Details will be presented in the 3Q/2012 issue.

- No. 3 bearing stationary seal.
- Peeling of paint from the engine frame.
- Spline adaptor wear.
- Variable stator vane (VSV) systems are "off-schedule."
- No. 4B bearing failures.
- Oil coking problems.
- Combustor issues.

In addition to discussion of engine parts, attendees participated in lively exchanges on GT-inlet air filters and water washing. Air filters are an agenda item at virtually every gas-turbine user meeting. The discussion at the LM2500 breakout focused on a performance comparison of prefilters/final filters and HEPA filters. A plant in the LA basin found value in switching to HEPA. A detailed analysis of HEPA filter performance was presented later in the meeting by a representative of Alliance Pipeline. That subject matter is summarized in the first of four short articles that follow this roundup.

Water washing predictably followed filters as a discussion topic. If you're not joining the "HEPA cures all ills" movement, water washing is necessary to maintain compressor performance. It seemed that everyone in the group had an opinion and wanted to be heard. Opinions were endless—perhaps taking half an hour, so it seemed—on online versus offline washing and which vendor had the most effective soap. Access to such information is one of several good reasons for attending the user group meeting catering to your engine; for GE aeros it would be Western Turbine.

Finally, a representative of Strategic Power Systems Inc (SPS), Charlotte, which has tracked performance metrics for owner/operators of LM engines since the organization was incorporated, addressed the group regarding systems and components adversely impacting reliability. Attendees were urged to increase the level of attention given to controls, the combustion system (including flame detection), package fire protection, and gas control valves. Sticking of gas control valves is an issue of increasing concern. The subject of parts-life tracking was also mentioned. For more on this subject see Article 2 and the end of this roundup report.

LM5000. The primary concern of owner/operators in this breakout was on-going concern regarding long-term support for the LM5000, no longer in production, from the OEM and depots. The group was told that GE is still supporting this fleet. But no mention

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was made about how long support might continue. "Where will we be in five years?" was one question asked. The OEM was said to have told at least some owner/operators it would not support maintenance service of third-party reverse-engineered parts.

What to do? Users are asking for a list of available parts; the OEM and depots want information from users. No easy answer to this standoff: Users don't want to commit to parts they might not need, suppliers don't want to make parts they might not sell. Perhaps an intermediary—SPS was mentioned—could handle the information exchange to the satisfaction of both sides.

Technical issues discussed included the following:

- Stage-0 corrosion in LP compressors.
- Torque-value concerns for LPC Stage-3 flange bolts.
- LTP stator cracks have been found on high-hours units. Typically, engines are making it through the second major but not to the third.
- VSV hardware issues.

LM6000. News item: The one-thousanth LM6000 was shipped in 2011. This is significant considering the first engine in the series was manufactured only about 20 years ago. Today the fleet totals 1015 units—about three-quarters of those equipped with a single annular combustor, remainder with a dry, low-emissions combustion system. Engines in service number 975, those operating stand at 766. Fleet operating hours are up to about 24-million, with the high-time engines (SAC/DLE) north of 130,000/120,000 hours.

Interesting audience demographics: By show of hands, as many as two-thirds of the attendees said they were first-timers. More than half the remainder said they had been attending the Western Turbine conference for five years or longer. One early discussion was on the variety of combustors found on LM6000s and the issues that drove design changes. A few users reported that they actually scrapped some new combustor designs and returned to the old.

The OEM presented on controls upgrade options. Users seemed pleased that the presentation defined benefits of upgrading from various control platforms to new ones. At the present time the Mark V will be considered obsolete in 2014, the Mark VI in 2019, and the Mark VIe in 2026.

SPS presented ORAP® data of interest to this group of users. It included mention of top contributors to forced outages and statistics on engine-removal duration and intervals for the past five years. Tom Christensen also spent a few minutes discussing a free tool available to users of its Operational Reliability Analysis Program to facilitate submittal of GADS reports.

Recall that the North American Electric Reliability Corp (NERC) collects event and performance data on gas turbines for its Generating Availability Data System—the same data SPS collects for ORAP. But because the formats for the two databases are different, NERC and SPS created a software program which both companies can use.

There were several presentations by owner/operators during the user-only sessions for the LM6000 track that generated considerable discussion. Two that stand out:

- Experiences from first-time engine removals. Half of the attendees had not participated in an engine removal. Think of the insights gained by these users from attending this session: certainly worth the meeting registration fee by itself.

  About 10% of those with applicable experience said they had issues removing their engines the first time. Outage preparedness was stressed as critical to success. One user discussed crane issues. His plant required a new crane and had to rent pins and pulleys from the OEM. Cranes are oft forgotten during outage preparation. Chalk that up to a lack of attention to detail in most cases. Remember that cranes, like elevators, must be checked by certified inspectors regularly. Forget this and your outage critical path can be adversely impacted before you get started.

  Another participant recommended using dolly skates under the engine container and making sure the concrete padding is sufficient to handle the weight. Get experienced people involved in your first engine removal or be prepared for surprises that inexperience will bring. One incident reported during the session was related to bearing scratches. Owner didn't think much about them; the depot insisted on replacement, adding to outage duration.
- Wiring issues, which contributed to phantom trips of several new units being installed at one site, were traced to poor subcontractor performance. Lessons learned: Contractors have the same difficulties as power producers when it comes to hiring capable people, and owner/operators are responsible for following and checking all work prior to sign-off.

  Here are several things that were overlooked on this project: (1) terminal boxes located below the evap cooler were not water-tight and condensation caused shorts; (2) termination boxes were not properly connected (poor wiring practice); (3) some boards were not grounded; (4) wiring in confined spaces was poorly executed. Impact of the poor workmanship was considerable. For example, the evap cooler had to be shut down because plant personnel could not access the board to fix it. Result was each unit being derated by 6 MW.

LMS100. The LMS 100 is quickly gaining in popularity. There are now 26 engines in operation and the fleet has amassed 110,000 operating hours and 17,500 starts; the high-time engine is at 22,000 hours. Only one engine was reported as operating in base-load service; the others are used either for peaking or cycling. Six more engines are in commissioning, three of those in California and the remainder outside the US. Expectation is that fleet size could double in a year.

The session was jump-started with a presentation on Black Hills Corp's Pueblo Airport Generation Station, equipped with two LM6000PF-powered 2 x 1 combined cycles and two LMS100 peakers, which began service on Jan 1, 2012 (Article 3 at the end of this roundup).

One attendee told the editors he believed the relationship between the OEM and the owner/operators had improved over the last few years and that there was a feeling of cooperation permeating the meeting room. It was not a complaint-driven discussion, he said. The GE portion of the program was particularly informative, the engineer continued, discussing more than a dozen programs aimed at addressing fleet issues. In at least several cases, the OEM and owner/operators were collaborating to develop solutions.

1. HEPA filters eliminate compressor washing

Alliance Pipeline relies on 19 DLE-equipped base-load gas turbines from Solar, Siemens, and GE to power compressors on its 1857-mile system of 3-ft-diam pipe that extends from gas fields in British Columbia to customer receipt points just west of Chicago.

The environment surrounding these units dictates water washing each spring, summer, and fall. In sum, each round of engine washing takes more


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1, 2. After 4300 hours of operation with HEPA filters in the gas turbine inlet and no water washes, the airfoils in the upper stator case of the Kerrobert LM2500 (left) and the first four stages of its HP compressor (right) remained pristine

3, 4. A borescope inspection after one year of operation on HEPA filters, showed the bellmouth and visible stages of the HP compressor for the Windfall G4 were "like new"

than 1000 man-hours and consumes more than 3200 gal of demineralized water and 30 gal of soap, which must be disposed of in an environmentally acceptable manner.

The pipeline's Rob McMahon told attendees of the Western Turbine Users' 22nd Annual Conference and Exhibition that his company had tested hydrophobic HEPA filters from W L Gore & Associates Inc, Newark, Del, on two engines for nearly two years before deciding to equip its entire fleet with those filters, thereby eliminating water washing and 57 outages from the company's annual schedule.

Alliance learned about the Gore filter from TransCanada Corp's experience at its Grandview Power Plant (access www.ccj-online.com, use the search function to find Grandview Power Plant).

Alliance began testing the filters in April 2010 at two locations with different operating environments: the LM2500+G4 in the Windfall pumping station at the start of the main line, the largest engine in the company's fleet, and a midstream LM2500 at Kerrobert in west-central Saskatchewan. Both engines showed a total system pressure drop of less than 1.5 in. of water with the new filters.

Six months (4300 operating hours) later, a borescope inspection of the Kerrobert HP compressor revealed pristine airfoils (Fig 1). With the top case removed for maintenance, McMahon said the compressor rotor was so clean it was as if had just returned from a shop overhaul (Fig 2). Generally, after six months of operation, the bell mouth and blades and vanes in Stages 1-5 would have been very dirty.

After one year of operation with the new filters, a borescope inspection of the Windfall G4 showed the bell mouth and visible stages of the HP compressor were clean (Figs 3, 4). An offline water wash was conducted but the wash fluid was white rather than the usual dark gray or black.

McMahon said that a water wash when the unit was equipped with conventional filters would have resulted in an efficiency increase of from about 1% to 2%. There was no improvement following washing when the Gore filters were installed. Reason: There was not dirt to remove, thus no performance loss had been incurred.

Based on the first two years of operation with the original Gore filters, expectations are that the filters should last at least another two years without replacement, making their service life comparable to that of the less efficient filters used previously.

2. OEM requires tracking of cycles on LM engines

The term "cycles tracking" got special emphasis in the plant manager's lexicon about seven years ago when the OEM assigned life limits to hot parts and required owner/operators to track engine cycles—specifically normal start/stop, trip from load, and partial cycles (step change). This followed a somewhat similar directive from the FAA for on-wing engines.

Goal: To achieve the highest level of operational safety by assuring that design-life limits of critical parts—rotors and disks, for example—are not exceeded. The editors were told by one attendee at last year's Western Turbine meeting that the requirement to track cycles is specified in engine O&M manuals. Some plants in the fleet are tracking cycles, but others still have no system in place for doing so.

A panel was put in place by WTUI at the 2011 conference to find out how LM owner/operators were approaching the challenge. There were three participants: Ed Jackson of Missouri River Energy Services, Chris Heiberger of Wellhead Services Inc, and Dan Dowler of Encana Corp.

Each participant explained the system his plant had developed to track cycles. The approaches differed, but all three of the self-developed solutions achieved the objective by providing the information required. None of the panelists said his plant was replacing parts based on results, but it was obvious to one attendee with considerable knowledge on the subject that this was coming—sooner rather than later.

1. Cycles tracking computer is small enough to hold in the palm of your hand

2. Rack space is not difficult to locate for such a small device

The same expert, while commending the plants for their initiative, suggested that the individual approach does not meet the intent of the directive because it's a fleet issue, not a customer issue. The proverbial fly-in-the-ointment is rotable parts. If the data have no pedigree, he said, you only will know the impact your operations have had on the lives of individual parts.

A better approach, he continued, might be to have an industry-wide data acquisition and analysis service track parts from plant to plant, machine to machine, and through repair processes. The service provider would alert owner/operators when parts in their machines were approaching end of life.

Early in 2012, the editors spoke with Larry Gasaway of Gasaway Engineering who confirmed that GE had added a chapter to its O&M manual on critical parts life management. It says, in part, "Critical life-limited parts are those parts that, should they fail, could threaten the structural integrity of the engine or its package. Stress cycles on gas-turbine parts result from transients of speed and temperature that occur during starts, accelerations, and decelerations. Therefore, life limits are expressed in terms of engine cycles and can be related to normal operational data."

GE goes on to say that "cycles must be recorded and tracked for each critical life-limited part." Plus, "It is the owner's/user's responsibility to establish a tracking system to ensure that adequate records are maintained for each critical life-limited part and that no such part exceeds its life limit."

Gasaway said there is only one commercially available system for LM users to count and track their cycles. Because most users are still not tracking cycles, he continued, this could leave them open for risk. If a part were to fail, insurance companies would investigate and discover that the user was not complying with OEM guidelines, and that could affect how the insurer handles the claim.

Tracking cycles manually has its drawbacks. Operators can miss cycles, fall out of the habit of recording them, or calculate them incorrectly. Installing an automatic counter mitigates this risk; it runs in the background and counts cycles automatically. Additionally, it generates reports that can follow the life-limited parts through maintenance cycles, depots, and different owners as it gets repaired and rotated around.

The cycle counter offered by Gasaway Engineering is a small computer that can plug into most control systems through an Ethernet port on the control system's network (Figs 1, 2). It will interface with most control systems and makes the information available as OPC data. Then the computer automatically counts the cycles and makes the raw cycle data available as OPC data.

An Excel add-in from Gasaway Engineering allows Excel to read the OPC data and manipulate it as desired. As an additional benefit, this system will make other engine parameters available to be read by Excel and it can then be used for still other calculations and reports. Added options can include thrust-balance monitoring, temperature-spread monitoring for fuel-nozzle troubleshooting, and compressor efficiency.

Gasaway Engineering also can run historical data through its program, to count past cycles. Additional network ports can be installed to interface with other networks to store cycle reports on networked PCs, send the data to other PCs to run the reports from your office, or send the information as OPC data to your DCS for display on HMIs or to be archived with the plant's existing historian. If the plant doesn't have a historian, or wants to keep this separate, one can be loaded on this computer to archive parameters monitored by the cycle computer.

The Gasaway cycles counter was said to be meeting or exceeding expectations on two base-load LM2500s in Southern California and three LM6000s at a plant in the Midwest.

3. Most advanced LMS100s, LM6000s in service power year's first GT

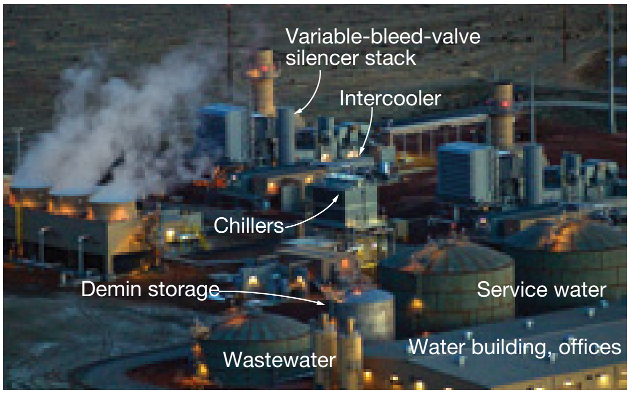
Black Hills Corp's world-class Pueblo Airport Generation Station became the first gas-turbine-powered generating facility to begin commercial service in 2012. The 380-MW combination simple-cycle/combined-cycle plant, began serving load on January 1. It is managed by WTUI Board Member Don Stahl and is located just over the fence from the Pueblo (Colo) airport.

The plant is unique. It features two LMS100 peakers owned by Black Hills Energy, a regulated electric utility serving 94,000 customers in southeastern Colorado (Fig 1) and two LM6000PF-powered 2 × 1 combined cycles owned by Black Hills Colorado IPP, an independent power producer (Fig 2). Both of these owners are, in turn, subsidiaries of Black Hills Corp. All generating units are located on the same site and operated by a common staff from a common control room.

Here's how this came to be. In July 2008, Black Hills Corp acquired five Aquila Inc utilities in four states, including its electric and gas utility operations in Colorado, where the company does business in as Black Hills Energy. At the time of the acquisition, Xcel Energy had already notified Aquila that its agreement to supply about 75% of the Colorado utility's electricity needs would not be renewed when the contract expired at the end of 2011.

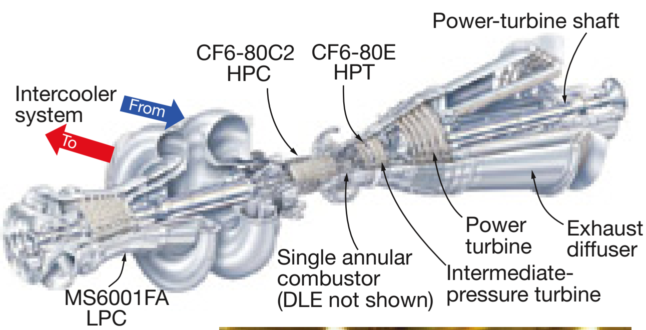
In August 2008, Black Hills Energy filed its Electric Resource Plan with the Colorado Public Utilities Commission (CPUC) and offered an analysis of the best and least-cost option for serving customer needs when the Xcel agreement expired at the end of 2011.

Director of Operations George Tatar, in Pasadena for the Western Turbine meeting along with Stahl, recalled that the resource plan "looked at every available option." System peak was slightly less than 400 MW at the time but was expected to be 406 MW in 2012 with an additional 61 MW needed for reserve capacity. The installation of fuel-efficient generation assets was a priority. Only natural-gas-fired facilities could be permitted and installed on time and the need to have the capability to back up inter-



1. Two LMS100s share one three-cell cooling tower to vent the heat of compression removed by the intercoolers. Wastewater tank collects drains, cooling tower blowdown, etc, which is then forwarded to an RO system in the water building. High-solids stream goes to the evap pond, low-solids stream to mixed-bed demin units. Demin water cools the combustion process to reduce NO_x emisions

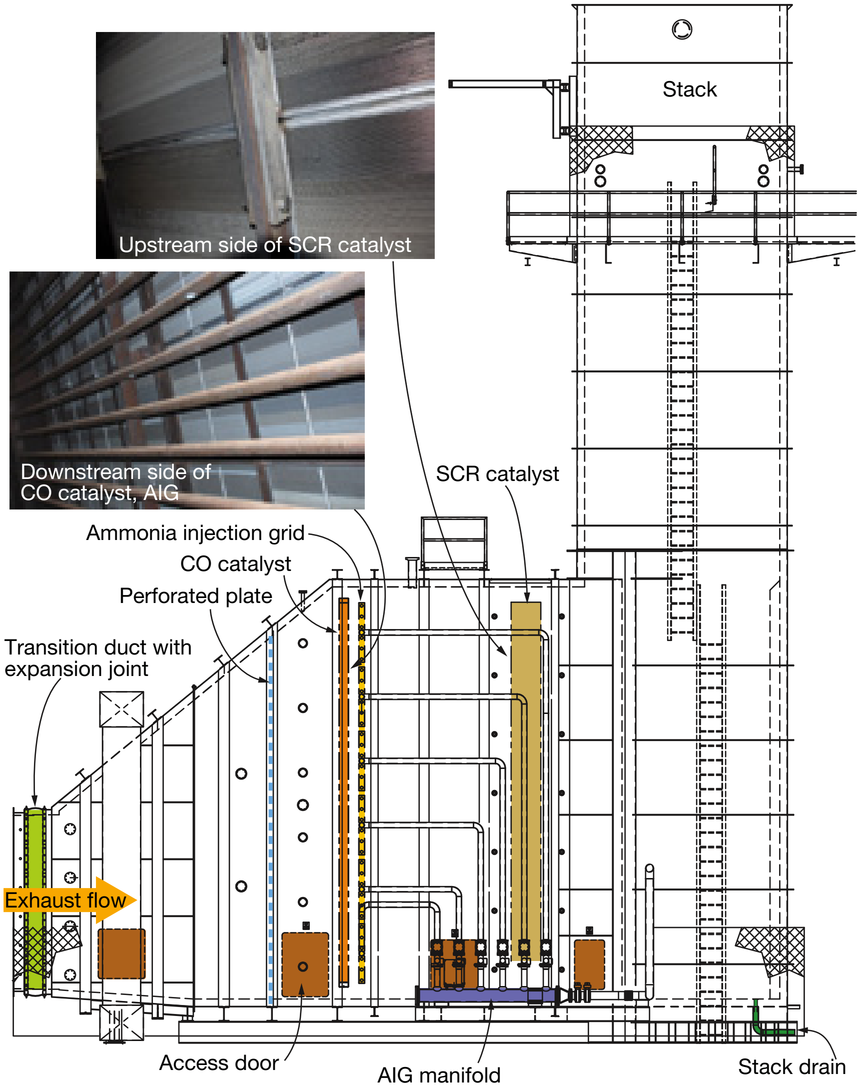
2. Two LM6000PF-powered 2 × 1 combined cycles at high noon

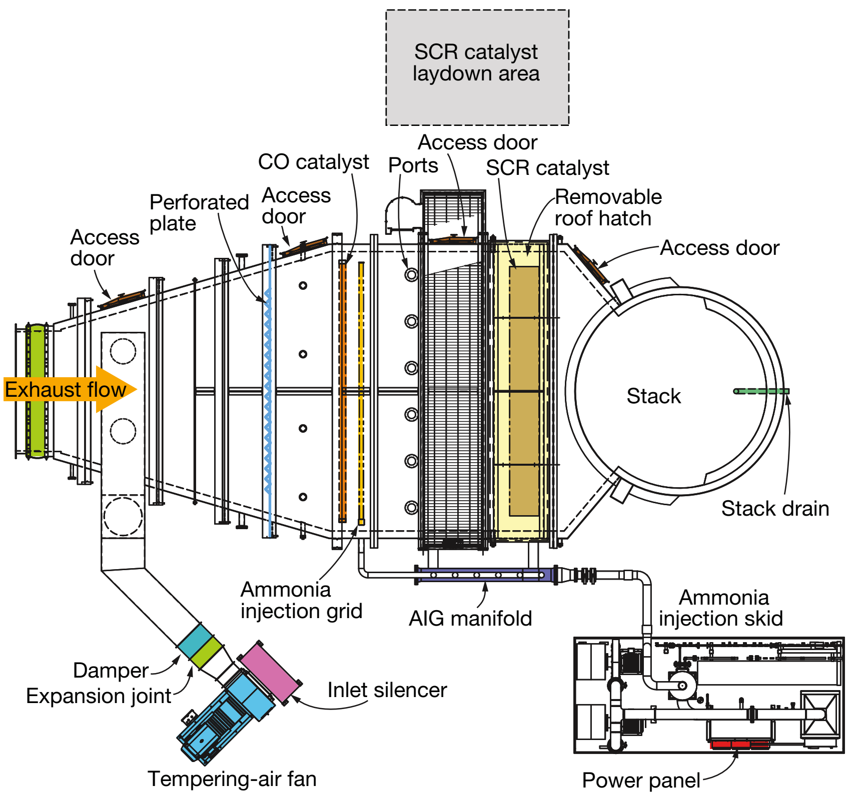


3, 4. LMS100 combines proven components from the OEM's aero and frame product lines. Photo is of the engine's supercore

mittent renewable energy resources required quick start natural-gas-fired facilities.

The two engine models installed on the Pueblo site were the only two gas turbines in GE's ecomagination™ product portfolio when they were ordered. To earn ecomagination approval, a product is evaluated for its ability to significantly and measurably improve the owner's environmen-





5, 6. Exhaust section for Pueblo LMS100 features redundant equipment (PLC connections to the plant DCS, tempering-air fans, ammonia vaporizers) to maintain NO_x and CO emissions within permit limits

tal and operating performance. The LMS100 offers a simple-cycle efficiency of 46% and is said to offer the highest level of performance of any aero on the market. The LM6000PF offers fast-start capability and low emissions (15 ppm NO_x).

In March 2009, the CPUC approved the construction of the two LMS100s by Black Hills Energy but decided that the company should conduct a competitive solicitation for the remaining capacity needed. An independent evaluator was hired to oversee the competitive solicitation. Black Hills Corp formed Black Hills Colorado IPP to participate in that bidding process. The unregulated subsidiary was selected as the winning bidder and received a 20-yr PPA (power purchase agreement) to provide the remaining energy needed to serve customers when the Xcel contract expired Dec 31, 2011.

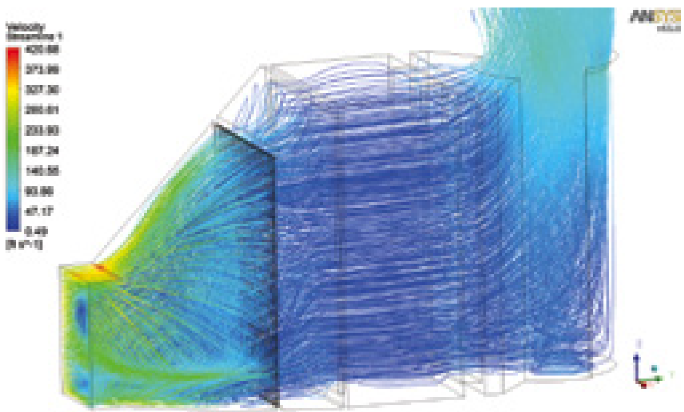
The LMS100 peakers are equipped with chillers (Stellar Energy Americas) in their respective Altair® air-inlet filter houses. The exhaust system, which includes catalyst and support equipment for NO_x and CO emissions reduction, was supplied by Braden Manufacturing LLC.

Recall that he LMS100 is a three-shaft gas turbine that uses intercooling technology to increase power and efficiency. It incorporates elements of on-wing and industrial gas turbines and is said to represent the most extensive collaboration of design and manufacturing expertise in the history of GE.

The six-stage LP compressor was derived from the MS6001FA; the so-called "supercore," which includes the 14-stage HP compressor, combustor, and HP turbine, is derived from the CF6-80C2 and CF6-80E aircraft engines that power many Boeing 747s and 767s (Figs 3, 4). Pressure ratio is 42:1. The HP turbine consists of two air-cooled stages; the IP turbine has two stages and the power turbine five. The generator is air-cooled.

Service intervals at this stage of engine experience are the following:

- Every 4000 hours, conduct borescope inspection. Planned outage duration is 12 hours including the cool-down time.
- Every 25,000 hours, hot-gas-path (HGP) inspection. Spare module—combustor and HP and IP turbines—is installed and the unit restarted within four days; owner's engine is sent to the shop for overhaul.
- Every 50,000 hours, major inspection. Same as HGP, plus power-turbine overhaul, LP compressor and shaft inspection/maintenance, and inspection of the following major components: booster, intercooler, scroll frames, HP compressor, aft shaft, and hydrodynamic bearings. Roller and ball bearings are replaced. There is a 60-day turn on all this work which can be reduced to four days if rotating spares are installed while shop work is done.



7. CFD tools were used to assure proper flow of exhaust gas from the gas-turbine outlet to the stack

Fleet operating history. Fleet RAM (reliability, availability, maintainability) stats are presented below. They were compiled by Strategic Power Systems, Charlotte, based on the 16 LMS100s reporting data through the company's ORAP® system for the period January 2008 through December 2010.

- Availability, engine only (including the intercooler). 94.7%.
- Availability, simple-cycle plant (including engine, generator, and station equipment), 87.7%.
- Reliability, engine only, 97.8%.
- Availability, simple-cycle plant, 94.6%.

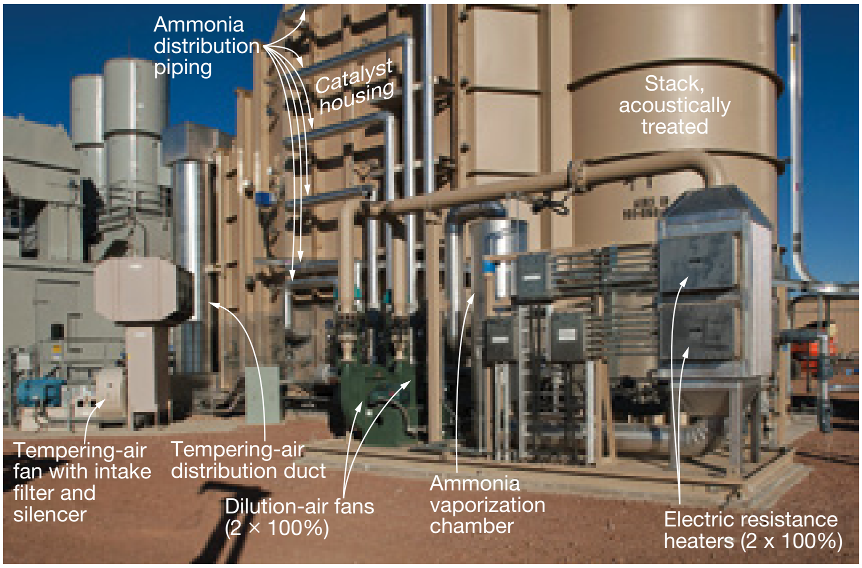
Starting reliability as reported by the OEM was 97.8% based on a 12-month rolling average through December 2010. The OEM's expected goals for a mature product—defined as 100,000 total service hours—is 99.2% reliability, 97.1% availability.

Exhaust section. Braden had total responsibility for the exhaust sections of both LMS100s. The project included supply of the NO_x and CO reduction systems (catalysts by Haldor Topsoe Inc and BASF's Catalysts Div, respectively), ammonia injection skids for the SCRs (provided by Braden subsidiary Consolidated Fabricators LLC), tempering air systems, exhaust stacks, and PLC connections to the plant DCS (Figs 5, 6).

The air permit for the LMS100s establishes limits sufficient to allow operation of all units 100% of the time. The limits for the two LMS100s are as follows:

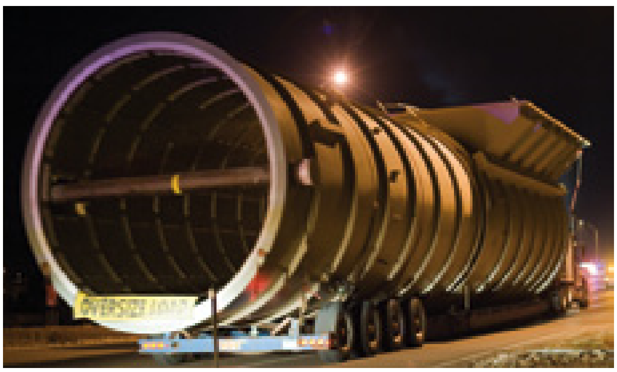
- NO_x, 5 ppmvd at 15% O_2.
- CO, 10 ppmvd at 15% O_2.
- VOC, 2.5 ppmvd at 15% O_2.
- Acoustic, 60 dB(A) at the fence line.

In designing the exhaust section,

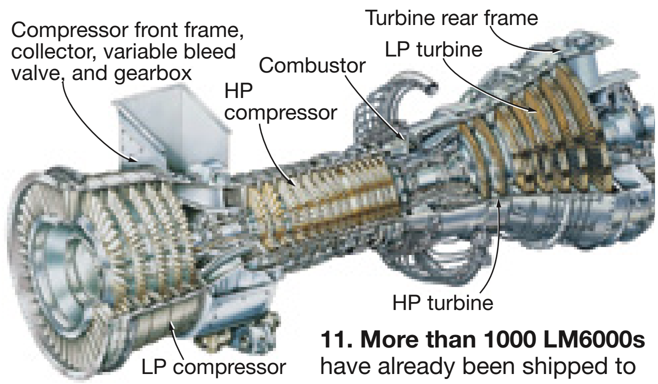


8. Ammonia injection skids for the SCR were fabricated, insulated, and wired before being shipped to the jobsite

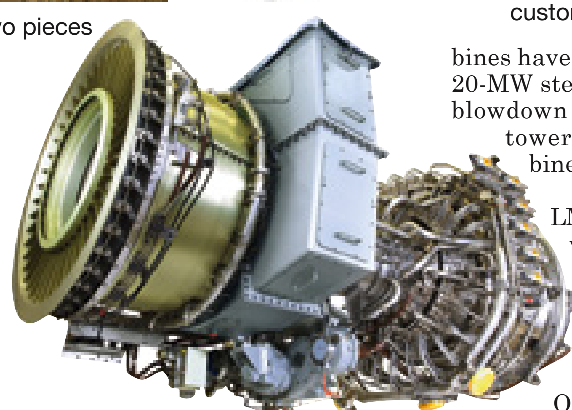
9. Very large subassemblies were prefabricated and shipped to Pueblo



10. Stacks were trucked to the site in two pieces



11. More than 1000 LM6000s have already been shipped to customers



12. LM6000PFs installed at Pueblo are each rated a nominal 40 MW

Braden was able to meet a tight schedule requirement by employing in-house engineering for all major disciplines—mechanical, electrical, structural. In addition, gas flow modeling was performed by Braden engineers along with acoustic modeling for stringent noise abatement. Pressure drop was a key concern to meet efficiency goals. Braden brought its years of experience in the design of ductwork and exhaust and silencing systems to bear to hold backpressure under 10 in. H_2O (Fig 7).

The ammonia injection skids were fabricated, insulated, and wired in Consolidated's shop to assure fast installation at the jobsite (Fig 8). And, to minimize fit-up errors onsite, Braden fabricated very large subassemblies offsite and trucked them to Pueblo (Fig 9). An additional benefit of pre-fab was a reduction in site labor requirements. High reliability of the exhaust sections is assured by use of redundant PLCs, fans, and ammonia heaters.

The insulated stacks (71 ft tall × 13.5 ft diam) have a floating liner system to accommodate the thermal cycles. The stacks were trucked to the site in two pieces for rapid erection on a foundation provided by Black Hills (Fig 10). Teamwork among personnel from Braden, Black Hills, the construction contractor, and the turbine manufacturer minimized the amount of time required for commissioning and verification of emissions permit requirements.

One cooling tower serves both LMS100s to release heat absorbed by water flowing through the engine intercoolers.

LM6000PF combined cycles. The two chiller-equipped LM6000PF gas turbines in both combined cycles are connected through dual-pressure Nooter/Eriksen Inc heat-recovery steam generators to a steamer made by Siemens Energy Inc in the Czech Republic. The 40-MW gas turbines have air-cooled generators, the 20-MW steamer water-cooled. Boiler blowdown is routed to the cooling tower provided for each combined cycle.

Interestingly, one of the four LM6000s installed at Pueblo was the 1000th of that model series shipped by GE (Fig 11). The LM6000 has a five-stage LP compressor and 14-stage HP compressor. Pressure ratio is 28.5:1.

On the turbine end, the HP unit has two stages, the LP turbine has six (Fig 12).

4. One way to quickly remove water, particulates from turbine oil

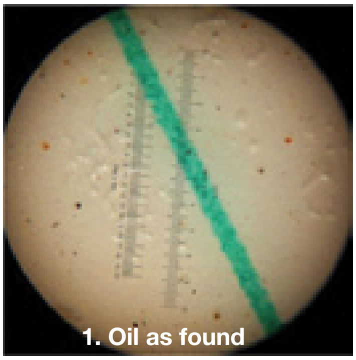
Plant managers are challenged to deal with the unexpected during virtually every outage. For Roger Bishop, the person responsible for a LM6000-powered 3 × 1 combined cycle and other assets at South Texas Electric Cooperative Inc's (STEC) Sam Rayburn Power Plant (Nursery, Tex), it was lube-oil contamination caused by a violent rainstorm in the middle of a January 2012 outage.

The Dresser-Rand steam turbine serving the nominal 180-MW combined cycle was down for maintenance and the rotor was out of the unit when rain hit, forcing water into the machine's lube-oil reservoir. This happened despite having tarpaulins covering the unit. Approximately 3000 gal of expensive turbine oil was contaminated to more than 6000 ppm of water—enough to turn the fluid milky. At this level of contamination, the oil oxidation rate and machine bearing wear increases by a factor of 10, putting millions of dollars of equipment at risk.

Time and cost are major considerations during most outages. The optimal solution for Sam Rayburn was offered by Oil Filtration Systems Inc, Boerne, Tex, located about 150 miles up the road from the powerplant. Within a matter of hours, OFS had one of its Vacuum Dehydrator Oil Purification Systems (VDOPS) onsite. Its state-of-the-art filtration technology can reduce the amount of water in turbine oils to as low as 20 ppm and the concentration of particulates to meet or exceed new-oil cleanliness specifications—typically ISO 16/13/10 or better.

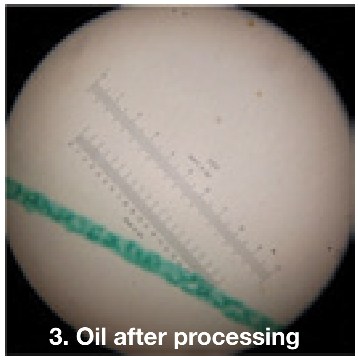
VDOP systems are simple to operate and require only electricity to remove particulates, dissolved gases, and water from oils. The equipment, virtually maintenance free, is designed both for fast hookup and for 24/7 operation in outdoor environments.

Processing of the contaminated oil (Fig 1) began just before 8 p.m. the day OFS was called by STEC. The VDOPS (Fig 2) reduced the amount of water in the Sam Rayburn oil by 4000 ppm in the first hour and in less than two days achieved 45 ppm (chart). During that time, particulate matter went from 18/16/14 to 15/13/10 (Fig 3).



1. Oil as found

Prefiltration/dehydration ISO Cleanliness Code was 18-16-14. This translates to 2500 to 1300 particles per milliliter larger than 4 mm; 640-320 larger than 6 mm; 160-80 larger than 14 mm



3. Oil after processing

Final sample ISO Cleanliness Code was 15-13-10. This translates to 320-160 particles per milliliter larger than 4 mm; 80-40 larger than 6 mm; 10-5 larger than 14 mm

VDOPS processing quickly reduces the concentration of water in turbine oil

Day/time	Water, ppm
1, 1940	6000
1, 2040	1911
1, 2230	1469
2, 0050	740
2, 0230	711
2, 0445	506
2, 0650	291
2, 1030	175
2, 1330	104
3, 1500	45

2. Vacuum dehydrator oil purification system extracts water and particulates from contaminated turbine oil

These results were verified by OFS' onsite portable fluid analysis kit, which is used by technicians to chart progress and allow customers to see firsthand the improvement in the condition of their oil. Bishop said, "The Field Service Group of OFS was very knowledgeable about oil cleanliness standards and went above and beyond to get my turbine oil dehydrated and free of particulates."

VDOP systems are designed to work on wide range of fluids used in powerplants—including hydraulic and lubricating oils, diesel fuel, phosphate ester, transformer oil, etc. They can remove 100% of free and emulsified water from these fluids, as well as 90% of the dissolved water (down to 20 ppm). Regarding solid contaminants, particle counts as low as ISO 12/10/9 can be achieved with high-efficiency 2.5 Beta(c)>1000 filter elements.

In addition, the VDOPS can be equipped to remove varnish, acid, and entrained air or gas as required. OFS offers contract field services and equipment rentals, as well as purchase options. Several units are assigned to strategic locations to allow a rapid response for the company's field service business. CCJ

New user group focuses on the integrated plant, staff, not specific equipment

Planning for the Combined Cycle Users Group's second annual meeting in Orlando, October 16-19, is well underway, reports Calpine's Larry Smart, the organization's chairman. Recall that the CCUG was launched last year as an independent, user-directed group to serve owner/operators of combined-cycle, combined heat and power (CHP), and cogeneration plants. It is distinguished by the logo in the sidebar and not affiliated with any other group of the same or similar name, nor is it associated with any other industry event.

The CCUG's meetings are dedicated to formal presentations and attendee-driven discussion sessions focusing on the design, construction, operation, and maintenance of the integrated plant. Additional topics addressed include NERC and other regulatory impacts on plant operation, environmental rulemakings, plant mods to achieve performance goals, safety initiatives, professional development, skills training, etc. There is no vendor fair associated with this event.

Presentation topics at the group's inaugural conference, Oct 31-Nov 2, 2011, in San Antonio, included the following:

- Cycle design improvements to boost availability, improve performance, reduce emissions and costs.
- Planning for 2020.
- High-energy piping inspection and repair.
- Water conservation and treatment.
- Combined-cycle operating challenges and changing paradigms.
- Challenges of modern control systems: Cyber security and beyond.

Summaries of the 2011 presentations are below. If you have questions or other thoughts on these topics, and are employed by a gas-turbine owner/operator, access the combined-cycle community by joining the discussion forum at http://ccug.users-groups.com. PowerPoints for most presentations can be found at that site as well.

Balancing act: Efficiency improvement versus cost reduction

Kajal Mukherjee, engineering technical director for WorleyParsons, was the ideal opening speaker. His broad knowledge of plant design and encyclopedic memory brought attendees up to date on OEM offerings and possible plant enhancements and how their financial returns compared.

Mukherjee took questions as he spoke, thereby expanding the scope of his prepared presentation, which was co-authored with Manager of Projects Andy Donaldson. This flexible format allowed some attendees to benefit from "free consulting." The information exchange was robust and the opening session ran more than a half-hour longer than planned.


Mukherjee

Details provided on advanced gas-turbine designs allowed participants to compare the latest models of Alstom, GE, Mitsubishi, and Siemens F-class engines by firing temperature, cooling system, combined-cycle arrangement, output, heat rate, and experience. A similar comparison was possible among G air- and steam-cooled offerings, H-class engines, and Mitsubishi's

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J-class machine. A review of quick-start features, emissions, low-load parking, turndown, and ability to accommodate fuel variations generated considerable discussion.

Some of the data gleaned from the Mukherjee/Donaldson table:

- Firing temperature typically is 2550F for the latest F-class machines, 2730F for G- and H-class engines, and 2910F for the Mitsubishi J.
- Nominal combined-cycle outputs in a 1 × 1 arrangement are 275-330 MW for F-class gas turbines, 400 MW for G- and H-class, 450 MW for the J. For 2 × 1 plants the respective outputs are 550- 660 MW, 800 MW, and 900 MW.
- ISO heat rates based on the lower heating value of fuel compare this way: F, 6000-6100 Btu/kWh; G, 5900; H, 5830; J, 5750.

Another segment of the Mukherjee/Donaldson presentation compared generation options in terms of performance, cost, and emissions, much of this information taken from government reports. A simple-cycle advanced GT was the least expensive of the 22 alternatives evaluated, coming in at just under $700/kW; municipal solid waste was the most expensive at more than $8000/kW. Advanced pulverized coal with carbon capture and storage (CCS) and nuclear were near the middle of the pack with costs of about $5100/kW and $5300/kW, respectively.

An F-class combined cycle burning natural gas and equipped with CCS offered the lowest emissions: 87 lb CO_2/MWh (gross); 0.06 lb NO_x/MWh (gross). The same unit without CCS released 790 lb CO_2; NO_x emissions were unchanged.

Where water use is a major concern, the conventional F-class combined cycle burning natural gas offered the lowest consumption at 3.3 gpm/MW (net). Water consumption for a subcritical pulverized-coal-fired plant would be nearly five times that amount.

Market drivers and trends cited by the WorleyParsons engineers included the following:

- New natural-gas resources and stable gas prices will continue to support generation-capacity additions with combined-cycle plants.
- Combined-cycle additions also will be favored for their shorter construction schedule, higher efficiency, lower emissions, smaller carbon footprint, lower water consumption, and lower capital investment compared to alternative generation options.
- Supplemental firing provides relatively low-cost incremental capacity to support peak demand requirements with moderate heat-rate impact.
- Steam temperatures above 1050F for advanced combined-cycle plants are compatible with today's HRSG and steam-turbine technologies.
- Dry or hybrid cooling is expected to gain market share because of growing water conservation concerns.
- Fast start/rapid response plants are gaining popularity in some areas to (1) increase ancillary services revenue, (2) reduce startup emissions and fuel consumption, and (3) move up in the dispatch order to increase revenue.
- Capacity factors of combined-cycle plants are expected to increase.

Mukherjee urged attendees to pursue efficiency improvements because of their positive impacts on ecology and economics. He offered this example: A 50-Btu/kWh improvement in net plant heat rate (higher heating value basis) for a typical 600-MW, 2 × 1 F-class combined cycle reduces fuel consumption by 135,000 million Btu/yr, CO_2 emissions by over 8000 tons/yr, and annual fuel cost by about $690,000. The foregoing numbers assume operation for 6000 hr/yr, 92% plant availability, $5 natural gas, and CO_2 emissions of 810 lb/MWh (net).

The gas turbine is the "master" in a combined-cycle plant, the engineer continued, and it plays the most important role in efficiency improve-

ment. However, rigorous engineering is critical to extracting maximum efficiency from the balance-of-plant design. He presented a checklist of areas demanding your attention at the design stage, and during operation, including these:

- HRSG pinch points, approach, pressure drops.
- Main and reheat steam system operating pressures and temperatures.
- Steam piping and reheater circuit pressure drops.
- Steam turbine design and backpressure.
- Cooling-tower approach and range.
- Condenser terminal temperature difference.
- Reduction of unnecessary margins on equipment rating.
- Use of premium-efficiency motors.
- Pressure drops in all piping systems.

In closing this portion of his presentation, Mukherjee noted that the individual impacts may not be significant, but in combination they can provide respectable performance improvements. He urged conducting design work in close coordination with equipment vendors to ensure commercial availability and maturity of the proposed design options. Then he stressed that nothing comes free. Capital cost increases are associated with most performance improvements and a cost/benefit analysis is necessary.

The staffing conundrum

Ask a roomful of powerplant O&M managers what their biggest challenge is today and staffing is virtually sure to be at the top of the list for more than half of those present. There are many reasons for staffing concerns, particularly at generating facilities powered by gas turbines: ageing workforce, staff reductions driven by headquarters directives, salary caps, no pool of experienced prospects, etc.

A big unknown at many plants is how the facility will operate five or 10 years down the road: Will they be peaking, base load, tied to ancillary services agreements? What will plant personnel be responsible for? Will they do all O&M, or just operations and light maintenance, with the heavy maintenance being handled by outside contractors? If you cannot answer questions such as these confidently, how can you hire and retain the right people?

NV Energy's VP Generation Kevin Geraghty made "right-staffing" a priority and launched a fleet-level initiative, "Workforce 20/20," last year to prepare the utility's generation department for the future. Peter Steinbrenner, manager of plant engineering and technical services, and a key leader on the nine-committee task force assembled to develop a plan for accommodating both the "silver tsunami" and an evolving generation portfolio, explained the process to CCUG attendees.


Steinbrenner

Simply put, Steinbrenner said, the goal is to create a system to continuously evaluate, define, and produce the competencies and skills necessary to meet the company's business needs. The process selected relies on Hoshin methodology. According to Wikipedia, Hoshin is intended to help an organization do the following:

- Focus on a shared goal.
- Communicate that goal to all leaders.
- Involve all leaders in planning to achieve the goal.
- Hold participants accountable for achieving their part of the plan.

Steinbrenner was well prepared and shared with the group NV Energy's challenges with respect to changes in operating technology, increased regulation, renewables generation, and economic pressures. He also put up a chart with numbers of potential retirements within one year, between two and five years, and those five years or more away for key positions, including: welder, technician, supervisor, operator, mechanic, engineer, apprentice, etc. That started a dialog between attendees and speaker that continued for several minutes. It appeared that most companies had not pursued such studies with comparable rigor.

Steinbrenner continued with an overview of the task force and its three-dozen participating employees, which are aided by an outside facilitator. One of the committees, he said, is responsible for determining what energy supply will look like nine years from now; another is charged with identifying the types of service-level agreements that may be required for internal/external services providers; yet another is responsible for creating job-analysis questionnaires and job descriptions for 2020.

Considerable discussion developed around Steinbrenner's explanation of so-called "core work," which is critical to Workforce 20/20 activities. He defined core work as all the duties required for NV Energy employees to produce electric power that cannot be obtained externally without increasing cost, reducing quality, or compromising reliability. More specifically, core work:

- Is critical to the business.
- Requires skills that must be developed internally and cannot be readily contracted.
- Is work that the utility can perform more cost-effectively and with much higher quality than external resources.
- Is highly specialized and requires skills very specific to the business of generating electricity.
- Is work that would put the company at risk if not performed to the highest standards of reliability and quality.

Then the speaker asked attendees what their criteria were for non-core work after explaining NV Energy's:

- Work that can be easily contracted.
- Work that can be performed more cost-effectively by contractors.
- Work that is more like a commodity and is not highly specialized.
- Highly specialized work—such as engineering design—that the company does not do consistently and cannot maintain expertise in the area.

Next, Steinbrenner asked the participants when they contract work, first offering his company's guidelines:

- During vacancies until filled.
- During peak workloads.
- When the company does not have the ability to maintain expertise internally equal to or better than that which can be purchased elsewhere.
- When safety, environmental, and OSHA compliance issues must be quickly addressed.

The give and take was significant, with both speaker and attendees learning from each other. On several occasions, Steinbrenner had to put down his microphone to make notes based on the experience of others in the room.

Steinbrenner closed his presentations with a list of key assumptions for the Workforce 2020 effort, including the following:

- Hire journeymen and train them to be operators.
- Contract most heavy maintenance.
- Consolidate control rooms.
- Convert maintenance managers into asset managers.
- Contract O&M for windfarms.
- Create one plant supervisor classification.
- Self-perform core work, contract non-core.

Several attendees acknowledged that their companies were already doing some of these things and considering others.

Tony Wiseman, a training director for Progress Energy at the time of the meeting, led a discussion on the practical challenges associated with the hiring and training of craft personnel. First, he pointed out the following differences in personal values for each of the four generations that may have to coexist in any given plant:

- Traditionalists (born 1928-1945) subscribe to conformity, stability, upward mobility, security, and economic success.
- Boomers (born 1946-1965) are characterized by personal and social expression, idealism, health and wellness, and youth.
- Generation X (born 1966-1979) are defined by their free agency and independence, street smarts, friendship, and cynicism.
- Generation Y (born 1980-2000) believe in hope about the future, collaboration, social activity, tolerance for diversity, and family centricity. Regarding the last characteristic, Gen Ys see their parents as role models and heroes. They trust authorities (such as teachers and police) in addition to their parents.

Next, Wiseman compared traditional craft structure to what's needed in today's combined-cycle plants. Traditional structure has a person trained as a mechanic, electrician, I&C tech, or operations tech—all separate and distinct crafts that begin at the apprentice position and progress through an intermediate stage to journeyman.

Skill overlap is required today to develop the multi-craft technician conducive to efficient plant operation. This is accomplished by having individuals specialize in one of the four disciplines noted above, and achieving journeyman status in it, while becoming proficient in the others.

To maximize the probability of success in personnel development, Wiseman suggested a multi-step plan that begins with a new-employee assessment. It consists of a written exam as well as an evaluation of deck-plates job skills. After the craft path is decided, specific training is initiated and the employee begins on-the-job training as an auxiliary operator. Simulators help here and eventually can bring the new hire up to the skill level required of a control room operator.


Buzza

In time, a "jack of all trades and master of one" is molded. Maintaining the skills taught requires an ongoing program of refresher training.

High-energy piping

Two solid presentations got the piping session rolling right after lunch on the first day—one on P91 piping fabrication guidelines by Dr David Buzza, senior engineer (metallurgist), for AEP Region 7; the other on risk-based assessments of high-energy piping systems by Consulting Engineer Jonathan McFarlen of M&M Engineering Associates, Austin, Tex. Comprehensive Q&A and discussion followed in the two-hour session.

Buzza reminded the group that Grade 91 material was developed for high-temperature service, its allowable stress being 2.5 times greater than that for P22 at 1080F. Thus P91 is much lighter than P22 for a given application by virtue of its thinner wall. This metallurgist, who spends a considerable amount of time on the deck plates elbow-to-elbow with plant personnel, shared his extensive practical knowledge on the set-up and control of post-weld heat treatment (PWHT) to achieve desired material hardness of 190 to 250 Brinell (HB) for components, 190 to 280 HB for welds.

Buzza reported on findings in both small- and large-bore piping (dividing line is 4 in.) at three combined-cycle plants in the Midwest. Both hard and soft components were identified with small-bore pipe as well as hard socket welds. Problems with large-bore piping focused on hard attachment welds and soft components (mostly elbows).

Well over a dozen components at the three plants had hardness readings from 316 to 390 HB, making them susceptible to overload or creep failure because of improper metallurgy. More than 10% of the socket welds at the plants revealed high hardness (300 to

439 HB). Numerous soft components (less than 165 HB) were found at two plants.

Improper PWHT is the root cause of P91 fabrication issues. For example, hard components are the result of exceeding the lower critical temperature (LCT) during PWHT followed by rapid cooling. Hard welds occur because the PWHT temperature at the weld never reached the hold temperature. Soft components mean PWHT temperature exceeded the LCT and that was followed by slow cooling; or PWHT hold time was excessive.

Critical to proper PWHT is sufficient thermocouples (t/cs). For example, when welding an elbow in to a drain line, t/s are recommended in the pipe segments upstream and downstream of the elbow, in the pipe elbow itself, and at the inlet and outlet welds where the drain piping lines up with an elbow. Proper heat treatment results in good hardness readings.

PWHT also must be monitored carefully during shop fabrication. For new units, drain pipe spools may be fabricated in the shop and then shipped to the field for install. It seems logical that under controlled shop conditions a good specification is all that's needed to assure proper welding and heat treatment. But don't believe it; take nothing for granted when it comes to P91.

The speaker spoke of that lesson learned in the fabrication of 2-in. socket-welded P91 pipe spools. After welding, the pipe spools were loaded into an induction furnace for heat treatment. Records showed that the target temperature and hold time had been achieved. Good thing hardness checks were in the spec: 100 of the 170 welds were too hard. Conclusion drawn was that the furnace temperature did not accurately reflect the actual weld temperature during the heat-treat process.

Keys to proper fabrication of P91 were discussed among the users. Here's one procedure, something you will not find in the ASME Boiler & Pressure Vessel Code.

1. Check incoming material.

- Ratio of N:Al on the material test report (MTR) should be greater than 4:1 and under no circumstances less than 2.5:1. It was said that the N:Al ratio is important because you want nitrogen precipitates, not aluminum.
- Hardness on the MTR, supported by in-house test results, should be 190-250 HB; 220 HB is optimal because hardness decreases with each PWHT cycle.

2. Specify verified heat-treat procedures.

- Follow AWS D10.10, which provides guidance on the number of control zones based on pipe diameter, heating-blanket length, monitoring t/cs.
- Use heat-treat set-up sheets. Procedure should specify ramp rates, hold times, temperatures, placement of heating circuits, control t/cs, etc.
- Review heat-treat set-up sheets. For example, check that thick and thin sections are on different heating circuits; heating pads are in contact with the pipe (you don't want air gaps); control t/cs are near the center of the pad and at the location expected to be the hottest, etc.

3. Confirm proper heat treatment through hardness testing by a qualified technician. A rule of thumb: Base material hardness should be with 20 Brinell hardness points of initial readings.

M&M Engineering's McFarlen had a great deal of practical information to share with the group. He began with a risk-based evaluation of high-energy piping (HEP) and moved from there into an assessment of HEP. McFarlen said that although HEP is not formally defined by the ASME Boiler & Pressure Vessel Code, it generally refers to main steam, and hot and cold reheat—and more and more, boiler feedwater piping and steam extraction lines.

Risk is not constant over time, he stressed, adding that risk assessments must be revisited periodically to account for such things as the actual history of temperature excursions, age of the piping system, last inspection scope and results, etc. Key steps in assessing risk are the following:

- Define system boundaries.
- Catalog components in the defined system.
- Identify failure modes for each component.
- Establish failure probability based on industry experience. Example: Failure possibly occurring once per lifetime has a probability of 0.01 to 0.001.
- Establish the consequences of failure, usually in terms of financial impact and/or downtime.
- Calculate baseline risk per component/failure mode combination.
- Determine influential factors and apply weighting factors—that is risk modifiers—and recalculate risk.
- Prioritize inspection activities for each component based on risk using prudent engineering judgment within fiscal constraints.

A review of damage mechanisms was next. McFarlen presented a handy table of nine mechanisms, where they were likely to be found, and the nondestructive examination techniques for identifying them. For example, high-cycle fatigue generally is associated with branch/tee welds. Visual, mag-particle, and ultrasonic inspection technologies are used to identify HCF.

McFarlen's segment on HEP assessment acknowledged that these piping systems, while not inspected routinely, cannot be taken for granted. Any pressure release could cause serious damage and/or personnel injury. An evaluation program encompassing the piping system and its supports allows an assessment of boiler external piping for use as the basis for continued service.


McFarlen

Piping support basics was of primer of value to many in the room. McFarlen addressed the following:

- Flexible hangers. They are used when vertical travel of a piping section is required because of thermal expansion.
- Rigid hangers—including rod hangers, stanchions, slide plates, spider guides, travelers, etc. They are used to support a section of piping where no or minimal vertical expansion is expected.
- Snubbers, which are used to arrest dynamic loads from hammer events or seismic loading.

Hangers generally are over-designed, the piping expert said, but problems can and do occur. For example, malfunctioning supports can lead to excessive localized loads and subsequent piping damage. Flexible hangers are prone to internal damage—such as corrosion, debris buildup, nesting birds, etc—which can arrest or restrict travel.

Your piping-system assessment should include a visual inspection and hanger survey. Observations such as areas of uplift or sag, interference, corrosion, etc, should be noted and investigated. Deformation and interference may indicate excessive loading; wetted areas may pinpoint areas of external corrosion where crack initiation may nucleate.

Survey hangers during hot and cold walk-downs; document hanger positions with photographs and written reports. Be sure to describe physical condition of the hangers in adequate detail. After taking hanger readings, compare the data collected to the "as-design" setpoints.

You may find that based on walkdown observations, a pipe stress analysis may be required. And based on the results of that work, NDE may be necessary to accurately determine the condition of your piping.

Corrective measures can be as simple as adjusting hangers, which is not always so simple. To illustrate: Hangers that travel less than designed/expected may require load testing. Depending available space, testing can be done in place with a dynamometer to assess functionality. Sometimes, just "working" the hanger during testing can clear out debris and return the component to full functionality.


Sampson

Bottomed-out or topped-out hangers may merit NDE of attachment points and circumferential welds. Stress analysis sometimes is necessary to justify NDE. Sections of pipe with deformed supports should be carefully inspected with the latest NDE tools without hesitation.

McFarlan encouraged participants that a visual examination/hanger survey of HEP is a good start to ensuring piping reliability and that plant personnel can do this with some fundamentals training. Higher-level evaluations (stress analysis and NDE) likely will require outside support. For more background on the subject, access "How to assess the health of high-energy piping systems," 1Q /2009, p 104.

Water conservation, treatment

The Monday afternoon session on water conservation and treatment featured as speakers two of the electric-power industry's top chemists: Jim Witherow, executive chemist, Scientech, a business unit of Curtiss Wright Flow Control Co, and Dan Sampson, senior technical consultant, WorleyParsons. The former focused on boiler-water chemistry, the latter on water conservation.

Witherow opened his presentation by outlining the following goals for an HRSG chemical treatment program:

- Provide optimized corrosion protection to all wetted surfaces.
- Minimize operator intervention.
- Support water conservation principles.
- Be cost effective.

His coverage of factors affecting water usage was brief. Witherow made it clear that if boiler chemistry were maintained within accepted industry specifications, makeup requirements generally would be acceptable. Blowdown, he said, must increase to purge contaminants allowed into the steam cycle as well as those produced in the boiler and other equipment when system chemistry gets out of control.

Poor quality makeup and condenser tube leaks, for example, forces plant operations personnel to increase blowdown to control silica, chlorides, sulfate, conductivity, and pH. Control of particulates from general corrosion and flow-accelerated corrosion (FAC) also is managed by regulating blowdown.

Witherow next introduced all-volatile treatment (AVT), plus a solid alkali program to increase corrosion protection in evaporator drums, as the foundation of sound water chemistry program. For all-ferrous systems typically identified with combined-cycle plants he suggested AVT(O), with ammonia as the neutralizing amine. Elevate feedwater pH to 9.2 minimum, the chemist recommended, do not use chemical reducing agents, and hold dissolved oxygen to between 1 and 10 ppb.


Witherow

An oxidizing environment, Witherow said, particularly one with a pH of 9.2 to 10, reduces iron solubility. That offers protection against FAC, most often found in LP evaporators and economizers with fluid temperatures typically ranging from 250F to 350F. Metal thinning occurs in areas where turbulent flow is present—such as where piping diameter changes, where there are bends and elbows, and where thermo-well penetrations exist. Mild steel wears relatively fast, Witherow added, and suggested use of T11 and T22 to prevent its occurrence.

However, AVT(R) is necessary for copper-bearing systems, he reminded. Minimize dissolved oxygen with a chemical reducing agent, minimize the addition of a reducing agent to maintain the desired oxygen level, and accept a slightly lower pH control range. Its important to closely monitor piping and tubing for FAC; replace affected components with ones made from chromium-bearing alloys.

Solid alkali treatment for evaporator drums increases the tolerance for contamination and contributes to reduced rates of blowdown. It also acts as a buffer to minimize pH swings. The addition of sodium phosphate to LP, IP, and HP evaporator sections, Witherow said, reduces FAC, promotes pH stability, and contributes to corrosion protection.

The chemist talked about two forms of phosphate treatment: coordinated/congruent and trisodium alone. The former is the classical, high-level treatment with varying mixtures of mono, di, and trisodium phosphates. It is beneficial for changing pH when contamination is high; not usually recommended for HRSGs; may lead to additional blowdown. There are two ranges of trisodium phosphate treatment depending on the level of contamination level. One provides 0.3 to 3 ppm phosphate; the high range, 3 to 10 ppm of phosphate.

Disadvantages of phosphate treatment, reminded Witherow, is carryover and hideout. The former can cause superheater and steam-turbine damage. The latter reflects the lower solubility of phosphate as temperature (pressure) increases and can lead to pH and conductivity instability as well as promote under-deposit corrosion.

Sampson discussed the water-supply challenges facing the electric power industry going forward and commented on the options available to generation companies for minimizing consumption. His back-of-the-envelope assessment for a combined-cycle plant equipped with a conventional mechanical-draft cooling tower: 60% to 90% of total plant water consumption is unrecoverable. Losses include cooling-tower evaporation and drift, gas-turbine power augmentation and evaporative cooling, steam losses, etc.

By subtraction, recoverable/recyclable water streams for the same plant amount to 10% to 40% of total plant water consumption—including cooling-tower and HRSG blowdown, pretreatment system wastewater, plant service water, leaks, and drains.

Rules governing water use and discharge keep changing and virtually every new regulation impacts a powerplant's treatment and consumption strategy. Sampson said that permitting bodies may require consumptive reduction or recycled water use to balance increases in water withdrawls to accommodate population increase, changes in weather patterns (droughts), etc.

He also mentioned limits on total dissolved solids (TDS) for plant discharges to publicly operated treatment works (POTW) and natural waterways as impacting plant water-use and treatment strategies. New ion-specific limits on phosphates, sulfates, etc, are an overlay on those rules.

The portion of Sampson's presentation on water conservation myths offered an opportunity for attendees to rethink their "beliefs." Perhaps the three biggest misconceptions, he said, are these:

- Higher cycles of concentration can save lots of water.
- Zero-liquid-discharge (ZLD) systems can save lots of water.
- Once-through cooling uses lots of water.

Regarding the "higher cycle myth," Sampson offered these numbers: A

2 × 1 F-class combined cycle with a mechanical-draft tower evaporates 2000 gpm. Makeup is 3000 gpm at three cycles, 2250 gpm at nine cycles. Thus, tripling the number of cycles saves only 750 gpm (25%). The same plant with an air-cooled condenser (ACC) averages 200-300 gpm of total makeup (not just the tower)—a saving of 2700-2800 gpm (90%).

The "ZLD myth" parallels the higher-cycles myth, he said. ZLD recovers 97% of cooling-tower blowdown, lowering makeup from 3000 gpm to slightly more than 2000 gpm at three cycles of concentration. The ACC option offers a much greater saving in water. Plus, you don't have to deal with the migraines associated with many of the ZLD systems.

Once-through cooling is *non-consumptive* and fits the same water-usage profile as an ACC. However, chemicals and heat are added to the water prior to its discharge from the plant. Once-through cooling is increasingly prohibited by permitting bodies.

Summing up the myths, Sampson noted that air-cooled plants minimize water consumption but ACCs can add significantly to both capital and operating costs, once-through is very dependent on location/permitting, and ZLD is not worth the effort and cost. What's left? Recycled water, which is what the consultant believes is the best option by far—especially when it is coupled with efficient use of water onsite.

Recycled water offers the following benefits, Sampson said:

- Reduces plant operating cost because recycled water is less expensive than city water and the treatment costs are about equal.
- Reduces the demand for potable water.
- Makes use of a resource that's often wasted.
- Minimizes environmental impact.
- Provides a virtually drought-proof water supply.

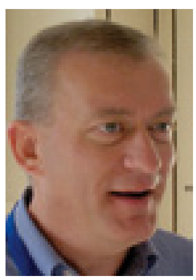
When using recycled water, Sampson continued, focus on the cooling tower. Do not use it to make demin water; it will produce operational headaches. Use potable water to make demin water and send both demin-system (reverse-osmosis rejects, etc) and low-TDS waste streams to the cooling tower as makeup.

The balance of the consultant's presentation covered system/equipment changes (mechanical, operational, and chemical) needed to make the use of recycled water a positive experience. Final suggestion: Don't transition to recycled water without a detailed roadmap and monitoring plan.

Permitting challenges

Kevin Davenport's presentation on permitting challenges for combined-cycle facilities was an eye-opener for all attendees who hadn't had recent involvement in the design of new units or in the upgrade of existing gas-turbine assets. Davenport is a specialist in air permitting and compliance for TVA and deals with regulatory challenges daily.

He began with the requirements for New Source Review (NSR) and Prevention of Significant Deterioration (PSD). The first pertains to a *new* or *modified* source—not routine maintenance, repair, or replacement—that results in a significant increase in emissions. Note that "modification" can be a physical change or a change in the mode of operation.


Davenport

Important: For non-attainment areas, NSR requires the Lowest Achievable Emission Rate (LAER), analysis of alternative sites, ambient modeling, offsets, EPA input, and public hearing.

PSD for attainment areas requires Best Available Control Technology (BACT), ambient modeling, impact analysis, and input from EPA.

More detailed requirements include the following:

- For combined-cycle plants, SO_2, lead, and sulfuric-acid mist should not be of concern because emissions typically are below the threshold requiring BACT/LAER analysis.
- NO_x, VOC, all PM and CO require BACT/LAER analysis. Davenport stressed that limits continue to drop and averaging times are getting shorter. Examples: (1) NO_x BACT is at 2.5 ppm today. (2) The 8-hr emissions average that you might remember is disappearing; a 3-hr average is more typical and some states are already at 1 hr. (3) CO BACT is less than 10 ppm.
- NO_x, all PM, and CO must be modeled to determine their impacts on air quality.
- Under new EPA requirements, CO_2 will require BACT. Carbon capture is a technology which must be evaluated; however, it should fail the economic feasibility test unless you have a close neighbor that can use the CO_2. Heat rate is another important consideration, the group was told.
- Netting can work to your advantage if, for example, the combined cycle is located on the site of a retiring coal-fired unit. Recall that NSR netting is the procedure for determining if the net emissions increase is significant and subject to the major non-attainment NSR requirements.

Davenport next commented on rapid start, which was the subject of a later presentation. He said that rapid starts lower emissions of NO_x, VOCs, and CO during the startup cycle because the catalysts come to optimal temperature sooner. Your permitting authority may require consideration of rapid start as a BACT (depending on location), Davenport continued.

He added that since BACT is an economic evaluation, the cost adder (capital and O&M) for rapid start and the anticipated dispatch of the facility will determine if it is required.

Details on greenhouse-gas permitting followed the rapid-start discussion. Davenport said EPA is requiring BACT for CO_2 on new or modified sources where emissions of the pollutant increase by 75,000 tons/yr or more. He added that BACT will be included as an operating requirement in permits and would most likely be couched in terms of lb CO_2/MWh. It was said that EPA has proposed 800 lb CO_2/MWh for a base-load unit, which generally is considered a relatively low number among users.

A general feeling was the permitting authorities are not currently conversant on many factors affecting the heat rate of gas-turbine-based plants. This suggests that users be prepared to answer questions related to the following:

- Number of startups and shutdowns.
- Low-load operation and/or short run times.
- Operation on automatic generation control.
- Capacity factor.
- Seasonal effects on heat rate.
- Size and anticipated operation of duct burners.
- Degradation of equipment over time.
- Operation in a simple-cycle mode if permitted. Be sure to negotiate different limits for simple- and combined-cycle operation.

Certainly the most interesting part of Davenport's presentation was a discussion of TVA's negotiations with EPA in the permitting of combined cycles, one at a coal-fired plant scheduled for closing. Consider attending the next meeting of the Combined Cycle Users Group so you don't miss such valuable insights.

Fast-start/fast-ramp combined cycles to debut in California. California's Renewable Portfolio Standard (RPS) demands that 33% of the state's kilowatt-hours come from renewable resources by 2020—the most stringent such requirement in the nation. Integration of high percentages of renewable energy with electricity from con-

Speer

ventional resources requires flexible generating assets fired by fossil fuels. Fast-start/fast-ramp simple- and combine-cycle gas-turbine capability is expected to be part of the mix.

There are plenty of simple-cycle peaking engines available to back up intermittent renewables, but no combined cycles in the US capable of fast-start/fast-ramp operation at this time. The first two such plants are under construction in California: the nominal 300-MW, 1 × 1 F-class Lodi Energy Center nearing completion about 40 miles south of Sacramento, and the 624-MW, 2 × 1 F-class Oakley Generating Station (formerly known as Contra Costa) in the early stages of construction about 50 miles northeast of San Francisco.

The CCUG steering committee invited Ken Speer, assistant GM, Northern California Power Agency, to address attendees on the challenges and expectations associated with building the nation's first fast-start combined cycle. Speer, who came to NCPA from independent power business, is a power professional who sees the value of Lodi in being able to both follow wind and to operate as an efficient combined cycle in base-load service.

When the facility begins operating next summer it will be the most efficient natural-gas-fired powerplant in Northern California. A big benefit is that the agency's 14 member companies and two associate members will reduce their greenhouse gas emissions by up to 70%.

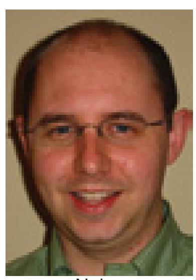
The power island is a Siemens single-shaft Flex-Plant™ 30, capable of delivering about 200 MW to the grid within 30 minutes (hot/warm start), 70 MW in 10 minutes. Bear in mind that short startup times reduce significantly startup fuel consumption and emissions. Fast start is enabled by a once-through Benson arrangement in the HP section of the triple-pressure, reheat heat-recovery steam generator. The IP and LP sections have steam drums like conventional HRSGs.

Best available control technology is applied to limit emissions of NO_x15 to 2 ppmvd, CO to 2 ppm, volatile organic compounds to 1.4 ppm, and ammonia slip to 10 ppm. Recycled water from the City of Lodi's White Slough Pollution Control Facility will be used for cooling-tower and boiler makeup. Tower blowdown will be treated and pumped into an underground injection well.

Paradigm shift

In retrospect, the CCUG's meeting in San Antonio last fall achieved its key objectives in the first day and a half: Solid presentations and discussions related to the design, operation, and maintenance of the total plant and critical systems/equipment generally not addressed by the model-specific gas turbine user groups.

But it was the final formal presentation, by Daniel Noles, manager of controls engineering, which supports TVA's coal and gas generation fleet, that showed the user group's value in identifying institutional changes sure to redefine how powerplants are managed in the future. TVA owns 15,000 MW of coal-fired capacity (59 units) plus 7500 MW of gas-fired capacity (87 simple-cycle engines and six combined-cycle units).



Noles

Noles' power generation expertise brought him instant credibility. Like many in the room, his experience was in plant processes and systems such as those used in combined cycles. Noles worked for an investor-owned utility prior to joining TVA, and he approaches control systems with a focus on improving the operation of plant equipment.

Noles opened by reviewing the importance of industrial control systems (ICS) to operational excellence and defining ICS as the gamut of solutions for controlling, monitoring, and protecting plant systems—including DCS, PLCs, single-loop controllers, supervisory instruments, protective relays, emissions monitors, field devices, etc.

The pathway to his discussion on challenges associated with cyber security began with a review of existing control systems and their limitations. The DCS world began with proprietary systems and transitioned to off-the-shelf technologies, so today we have a mixture of legacy and modern systems. Many of those legacy systems or their modern replacements have been connected to other networks for supporting business decisions. While cyber security is getting more focus in recent years, the interconnection of systems often leads to increased security risks.

Noles next discussed what he termed "general" control-systems challenges. System complexity was first on the list, and Noles stated that complexity often increases security or other risks related to control systems. Noles also noted that interconnection of networks, while providing opportunities for business cost savings, can lead to vulnerabilities if not properly secured.

Finally, he discussed challenges related to workforce demographics and trends. Challenges include identifying expertise, roles, and responsibilities necessary to properly maintain and secure control systems. While many technologies in modern control systems are similar to those used in IT systems, the two environments have significant differences and each require unique skill sets. Noles

Steam supply set-up for a fast-start combined cycle

The technology built into the Lodi Energy Center allows for faster starting of the gas turbines by mitigating restrictions normally associated with operation of the heat-recovery steam generator (HRSG) and steam turbine. Traditionally, gas turbines are stared up slowly, with long hold times at low-load points to limit stresses in the high-pressure steam circuit.

The Flex Plant 30 design avoids previous restrictions by eliminating the high-pressure steam drum from the HRSG. The once-through Bensen boiler arrangement used in the HP evaporator has two sections. After partial evaporation in the first section, the steam/water mixture passes through a downcomer and distribution device before entering the second section.

The star distributor prevents separation of the steam/water mixture and allows uniform distribution of the fluid in HP evaporator 2. The degree of superheat at the outlet of the second section varies depending on gas-turbine load and ambient conditions, and is controlled by feedwater flow. The slightly superheated steam exiting HP evaporator 2 flows through a steam separator to the HP superheater.

Lodi also has an auxiliary boiler to provide sealing steam for the steam turbine and sparging steam prior to gas-turbine startup. This allows pulling of condenser vacuum and rolling of the steamer earlier in the startup process. HP final steam temperature is controlled using either a final stage (after the second-stage superheater surface) or interstage (between the first and second stages) desuperheater. HP steam attemperation is not required for operation at the design point.

emphasized the need for collaboration among organizations such as IT, control system support, corporate compliance, and others.

There are still many challenges in the electric utility industry with regard to securing control systems. Several organizations such as DHS (Dept of Homeland Security), NIST (National Institute for Standards and Technology), and ISA (International Society of Automation) have published best practices and standards on the subject.

While the industry security standards exist, the primary regulatory compliance standards known as NERC CIP (Critical Infrastructure Protection) are still evolving rapidly in comparison to the timeframe required for implementing an effective compliance program. The current standards, CIP version 3, have been implemented at many utilities; however, there is uncertainty about whether the next step will be version 4, which is near final approval, or version 5 which could be approved by late 2012.

Noles provided examples of recent cyber events and groups responsible for them. Everyone present gained a new appreciation for the realities of cyber security risks that exist today. In recent years, high profile targets have often included financial institutions and governments, but critical infrastructure such as power and water industry control systems have increasingly become targets for cyber attacks.

They can be launched by disgruntled employees, outside individuals, organized crime, terrorist groups, or other governments. While the potential for cyber attacks is a serious threat to the country's infrastructure and economy, he noted that effective defense-in-depth strategies can be deployed to manage the risk.

Examples of best practices and essential security defenses were highlighted such as:

- Standardization and lifecycle planning , which reduces the complexity of security requirements.
- Network segmentation, which limits access points to control systems.
- Logical and physical access controls—such as card readers on doors or user passwords on devices.
- Backup and recovery of applications and data.
- Deployment of malware defenses, such as anti-virus programs.
- Security monitoring systems to detect abnormal network traffic.
- Incident response and forensic plans for preparedness in the event of a cyber attack.
- Management of change, which is required for compliance but often pays dividends in plant reliability.
- Information protection to minimize access to your control-system configuration details.
- Device and software inventories, which are required in managing security and documenting compliance.
- Secure configurations for hardware, software, and network devices.

The conclusion provided practical advice on building an effective cyber security program to minimize risks. One of the first and most important steps is to identify an executive sponsor who will ensure the program receives adequate focus and funding. Early stages of the program efforts should include assessments of current security practices, organization resources, and security awareness training. Establishing an effective and sustainable cyber security program will require significant funding and commitment.

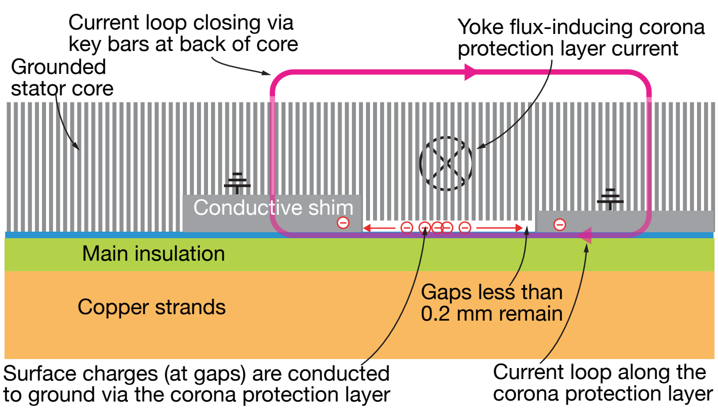
He closed by emphasizing the need for a strategic program that balances security, compliance, and business objectives. In his final remarks, Noles said, "We must not lose sight of the ultimate goal for control systems and cyber security programs [yes, including compliance] which is to sustain the safe and reliable operation of generation, transmission, and distribution assets that benefit each of us in our daily lives." CCJ

Efforts to locate, repair damage from spark erosion advance

Most gas-turbine user groups devote at least a few hours at each conference to presentations and Q&A on generators, with much of that time focused on air-cooled units installed at combined-cycle, cogeneration, and simple-cycle plants over the last 15 years or so. It's rare that a meeting passes without meaningful discussion of spark erosion (SE) and partial discharge (PD)—phenomena associated with air-cooled machines.

These subjects also have been addressed in recent **CCJ** articles. Access "There's nothing generic about generator failures" and "Diagnosing partial discharge, spark erosion" in the 2011 Outage Handbook at www.ccj-online.com/archives.

New methods for condition assessment and repair of air-cooled generators were included in a presentation at ASME's 2011 Power Conference in Denver, last July, by John Jensen, PE, senior generator design engineer, and Alfred Laforet, manager of generator products, Alstom Power Inc, Midlothian, Va. The complete paper, "Turbogenerator spark erosion inspection and repair," POWER2011-55337, is available through the society.



1. Vibration sparking can be traced to the interruption of circulating currents flowing in the conductive coating applied to the surface of the stator bars

The promise of the new methods described by Jensen and Laforet: A more objective and more accurate condition assessment than previously possible, one conducive to selection of the optimal repair for any given generator. The duo stressed that repair options short of a complete rewind are now available to restore the normal life expectancy of a generator, or to at least extend the machine's life until more extensive repairs can be planned.

The work by Alstom to mitigate spark erosion in generator stators identifies with two SE phenomena—one caused by capacitive slot discharges (partial discharges), the other by vibration sparking. The latter, a known effect in high-voltage machines, is conducive to rapid and severe insulation damage. Vibration sparking, the authors said, is distinct from the PD effect caused by interruption of current paths. Note that at least some other experts in the field are known to use SE and vibration sparking interchangeably.

Background. Jensen and Laforet began by providing valuable perspective on the damage mechanisms. Spark erosion, they told attendees, was first identified in the 1960s as generator manufacturers moved away from the use of asphalt-based insulation systems to epoxy resins. Asphalt insulation systems by their nature were prone to significant swelling during thermal cycling; this ensured that the bars maintained good contact with slot walls.

The transition to epoxy insulation systems required the use of semiconductive side fillers in the slots to maintain tight contact between the bars and slot walls. Compared to asphalt, epoxy insulation systems expand minimally during thermal cycling. Improper fit-up of side fillers promotes looseness in the slots, allowing the bars to vibrate, thereby enabling insulation wear and arcing associated with capacitive slot PD and vibration sparking.

The science of spark erosion

Vibration sparking, the co-authors explained, has its origin in the interruption of currents flowing in the conductive coating (slot corona protection) applied to stator-bar surfaces. These surface currents are created by magnetic flux in the stator yoke and are a normal occurrence in all generators.

However, by design, these currents normally are dissipated from the bar surface to ground through contact between the stator bars and core. The conductive corona protection coating on the surfaces of the bars, and the conductive filler material used to wedge the bars tightly in their respective slots, assure good electrical contact to the core (ground, Fig 1).

Vibration sparking occurs when the currents flowing in the corona protection coating are interrupted because of the movement of the stator bars relative to the slot wall. These axial currents flow from one point of contact with the slot wall to another via the coating. If one of the contacts opens to interrupt the current then there is a risk of sparking—depending on the distance between contacts and the magnitude of the current (Fig 2).

This type of sparking can occur only when stator-bar vibration exists. One of the factors influencing arcing is the level of the induced voltage in the loop built along the corona protection layer via contact points to the core and the key bar (refer back to Fig 1). Thus the resulting current depends on the induction design data for the generator, the axial resistance of the bar corona protection layer (R_{axial} in ohms/meter), and the lateral resistance (so-called contact resistance) of the corona protection layer ($r_{lateral}$ in ohm-meters). The combination of the axial and lateral resistance is known as the *contact coefficient,* defined as:

$$\alpha = (R_{axial}/r_{lateral})^{0.5} = 1/m$$

When a stator bar is installed and wedged in the slot with poor side filling, or if there are inconsistencies in the slot geometry, voids or gaps are created between the bar surface and core iron. These voids, or gaps, have electrical and mechanical consequences. For example, they reduce the contact coefficient when the contact resistance of the corona protection layer increases.

Additionally, without appropriate mechanical support, stator bars can vibrate in the slot, creating conditions conducive to vibration sparking. Operating time also impacts the risk of SE occurring.

High currents in the corona protection layer of the stator are exacerbated when material ageing and high temperatures contribute to reduced electrical resistivity of the conductive coating on the stator bars. The result is a decrease in the axial resistance of the corona protection layer. Bar vibration in the slot can be amplified over time by the loosening of radial slot wedges designed to maintain radial pressure on the bars and dampen vibration.

What the foregoing suggests is that the contact coefficient is a good indicator of vibration sparking risk because it accounts for both poor lateral contact between the bars and slot wall (risk of bar vibration) and low corona protection layer resistivity (risk of high currents in the corona layer).

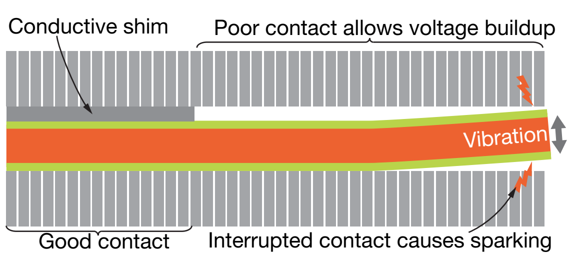
Jensen and Laforet also pointed out that the phenomenon of vibration sparking, unlike capacitive partial discharge, is not restricted to high-voltage bars. It can occur anywhere in the winding because the factors that cause it—slot vibration, poor lateral contact, and low resistivity of the corona protection layer—can be found anywhere in the winding.

Over time, the co-presenters continued, destruction of the corona protection layer through vibration sparking and the abrasive effect of bar vibration will, at the least, lead to capacitive discharges on bars exposed to highest voltages. They concluded the theoretical portion of their presentation with the observation that if sufficient damage is caused to the corona protective coating, SE phenomena, vibration sparking, and capacitive discharge can become superimposed on each other.

Inspection methods

There are several methods that can be used to inspect for the presence of spark erosion in a generator: visual, direct measurement of the contact coefficient, and partial discharge analysis.

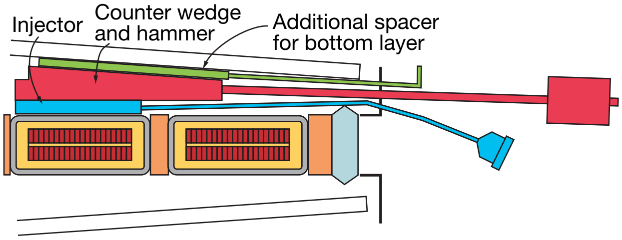
The use of multiple inspection methods was suggested by Jensen and Laforet to allow the best possible



2. Spark erosion is caused by vibration of stator bar in slot that leads to interrupted contact with the slot wall

3. Vent duct allows access for inspection and testing. Here, contact coefficient probes are inserted into the back of the core

4. Stator bars, undamaged in the vent duct area, show the effects of spark erosion further into the machine



5. Epoxy resin injected between stator bars and slot wall can eliminate spark erosion if caught at an early stage of deterioration

understanding of stator-winding condition. Here's what you should know about each of them:

Visual inspection is the primary method used to inspect for SE. Typically, a borescope is used to view the exposed surfaces of stator bars visible at the core vent-duct locations (Fig 3). This can be accomplished from outside the core or from inside the bore of the core.

Visual examination provides a qualitative evaluation of the bars and offers evidence of their relative condition. It does not provide a fully objective analysis of stator-bar condition. It also restricts the analysis to the areas of the stator bars directly visible in the vent ducts.

Experience suggests that the nature of spark erosion is such that even if there is no visible damage on the bars at the vent-duct locations damage may already exist between the bar and the slot wall (Fig 4).

Measure contact coefficient. This technique, developed by Alstom, is based on the injection of a current in the conductive coating on the outside of the stator bar and measurement of the resulting voltage distribution between the bar surface and the slot wall at several points along the bar in close proximity to the injection point.

How it's done: Several probes are inserted through adjacent vent ducts to contact the sides of the stator bar. The voltages obtained are used to calculate the axial resistance of the conductive coating of the stator bar and the contact resistance between the coating and the slot wall. Having these data, the contact coefficient can be calculated.

Jensen and Laforet said thorough evaluation of generator condition requires calculation of the contact coefficient using data taken from at least three axial locations along the bar length of every accessible bar. They added that, based on Alstom's experience, values of alpha greater than 8/m are indicative of good conduction between the stator bar and the slot wall and are expected for new windings.

Contact coefficients of 5/m or higher are normal for generators that have operated for a substantial period of time and have little risk of spark erosion. As alpha values decrease below this level, there is an increased risk of vibration sparking damage.

Partial discharge analysis also can offer clues as to whether any given generator suffers from SE. PD sensors normally are connected close to the high-voltage terminals of the generator in the isophase bus. Reason: PD activity associated with capacitive discharge within gaps is found in stator bars of a particular voltage level.

These sensors normally are used to measure the partial discharge effect, which is caused by the charging of defect locations (voids) with high voltage. Recall that vibration sparking can occur anywhere in the winding. When it occurs in the high-voltage bars, it normally is difficult to detect because it is masked by the capacitive PD activity that exists there.

However, the addition of a high-capacitance PD sensor at the neutral point, which can see all three phases from the neutral side, permits reliable identification of vibration sparking signals if such defects exist close to the neutral point. They can be seen clearly without interference from the PD signals associated with the high-voltage bars.

Repair options

There are several repair options to consider if you have a generator afflicted with spark erosion, including these:

- When SE damage is at a relatively early stage, it can be arrested by injection of a special conductive epoxy resin into the area between the stator bars and the slot wall to fill gaps conducive to spark erosion (Fig 5). Once the epoxy cures, it prevents bar movement and re-establishes electrical contact between the surface of the stator bar and the slot wall.

  Stator windings so repaired at an early stage should have a normal lifespan, the speakers said. If the epoxy solution is applied at a more advanced stage of slot sparking damage, it should extend the life of the existing winding, subject to monitoring, to that time when proper repairs can be made.
- Selective replacement of conductive slot side filling (primarily on top bars) can minimize slot looseness and poor conduction of the stator bars to the slot wall, thereby eliminating the root cause of spark erosion. New wedging methods can be used to increase the radial load applied to the stator bars, reducing the vibration of stator bars in the slot.
- When windings have already experienced extensive damage and inspections indicate their continued deterioration, a complete rewind is your only option. Important to remember is that your rewind must address the root causes of vibration sparking to prevent damage to the new winding. Also, keep these lessons learned/best practices in mind:
- Carefully install stator bars with conductive side filling to minimize any gaps between the bars and the slot wall.
- Be sure all components in the slot are made of conductive materials, or have conductive coatings, to maximize the area for conducting stator-bar surface currents safely to ground.
- Maintain conductive materials and coatings at a sufficiently high level of resistivity over time to dampen the development of high surface currents that would exacerbate vibration sparking were bars to loosen.
- Insure slot wedging creates a high radial pressure to the bars to minimize vibration and ensure good contact between the stator bars and the slot bottom. The latter is particularly important because this is one of the primary paths for conducting stator-bar surface currents. CCJ

Intercooling key to the commercial success of gas turbines

Most people begin their professional careers with little or no historical perspective about the industry they serve. They may absorb some history over time if they're interested in how things got to be the way they are and if they have a knowledgeable and sharing mentor. But more often than not, the clock starts with their first paycheck. This is unfortunate, because failure to learn yesterday's lessons means you are not inoculated against re-making past mistakes.

This point was driven home a couple of times during the recently completed seven-lesson webinar "Generator Monitoring, Inspection, Maintenance," conducted by Clyde Maughan, one of the world's leading experts in generator forensic engineering (access www.ccj-online.com/maughan). At 85, and with 62 years of generator lessons learned behind him, one reason Maughan doggedly pursues his career is to help today's engineers avoid having to solve problems already solved.

Ageing professionals are prone to wince when they hear factually incorrect statements from those who should know better. CCJ editors are very aware of this. Recently a call came in from Sep van der Linden, president Brulin Associates LLC, Chesterfield, Va, who has more than 50 years of experience in gas turbine technical matters—and counting.


van der Linden

He was disappointed with a statement in a promotional brochure featuring the keynote speakers for the upcoming ASME Turbo Expo 2012 (June 11-15, Copenhagen) that said GE's LMS100 was "the world's first intercooled industrial gas turbine." Van der Linden said, "Not true! The first intercooled industrial gas turbines (IGTs) date back to the 1940s." In fact, he continued, the world's first 100-MW generating station powered by gas turbines had four nominal 25-MW intercooled machines. It went into service in September 1959 and "I was in Port Mann, Vancouver, BC, for the plant opening."

Van der Linden's point is important. His own career spans almost the entire timeline of industrial gas turbines, and when you add in first-hand information obtained from mentors, there isn't much about land-based engines for electric generation that he hasn't been exposed to. But even van der Linden is going to retire someday. Now is the time to gather up the knowledge the pre-1965 engineers have to share, lest the mistakes of yesterday become the mistakes of tomorrow.

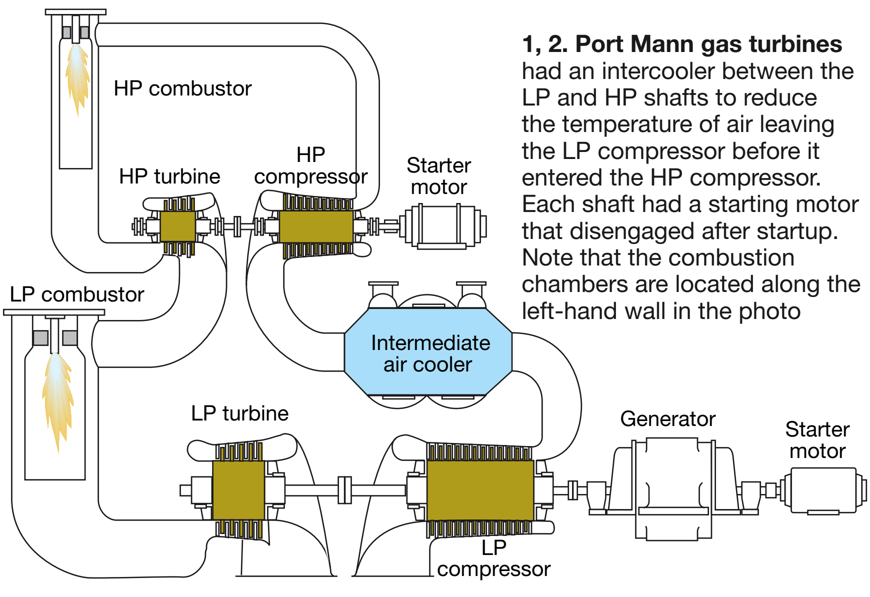
Intercooled gas turbines

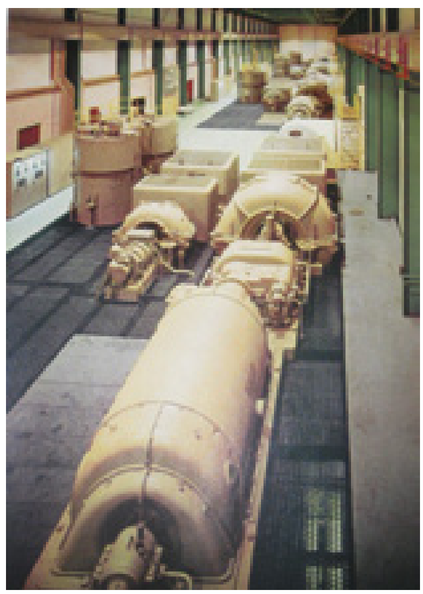
The Brown Boveri Corp (now Alstom) intercooled gas turbines at the remotely operated and controlled Port Mann Station, built by British Columbia Electric Co (today BC Hydro), were two-shaft machines arranged as shown in Fig 1. All four units were installed in-line in a building measuring 460 ft long × 82 ft wide × 59 ft high (Fig 2). This and the other photos shown here were scanned from print materials; neither the utility nor the OEM were able to locate the original images.

The gas turbines, which were capable of full-power operation 20 minutes after ignition, burned natural gas in summer and crude oil in winter in their single-burner HP and LP silo combustors (along the left hand wall in Fig 2). The generators/synchronous condensers were water-cooled. Air flow through the engines was 321 lb/sec, pressure ratio was 18:1, and efficiency 25%. Turbine inlet temperature was 1200F.

The LMS100 mentioned earlier, produces 100 MW in a single unit with an air flow of 460 lb/sec and pressure ratio of 42:1, illustrating how far gas-turbine technology has progressed during van der Linden's career. Rated output of the LMS 100 can be achieved in half the time the Port Mann turbines were capable of. More detail on the new engine can be found in the Western Turbine report elsewhere in this issue.

Van der Linden then continued the history lesson. Intercooled IGTs were





1, 2. Port Mann gas turbines had an intercooler between the LP and HP shafts to reduce the temperature of air leaving the LP compressor before it entered the HP compressor. Each shaft had a starting motor that disengaged after startup. Note that the combustion chambers are located along the left-hand wall in the photo developed for a time when fuel was scarce and heavy oil or steel-mill gases had to be used and high efficiency was important. The first commercial unit was completed in 1946 and factory-tested to full capacity (Fig 3).

However, post-war issues delayed the commissioning of that machine in Bucharest, Romania, until 1951. It was a two-shaft reheat, intercooled gas turbine rated 10 MW that achieved 12 MW with about half the air flow of the first commercial IGT commissioned only 12 years earlier.

Recall that the first industrial gas turbine, rated 4 MW and having an efficiency of 17%, was installed in a bomb shelter in Neuchatel, Switzerland, just before the start of WWII. For details, see the paper prepared by van der Linden when GT Neuchatel was designated a Historic Landmark (http://files.asme.org/asmeorg/Communities/History/Landmarks/12281.pdf).

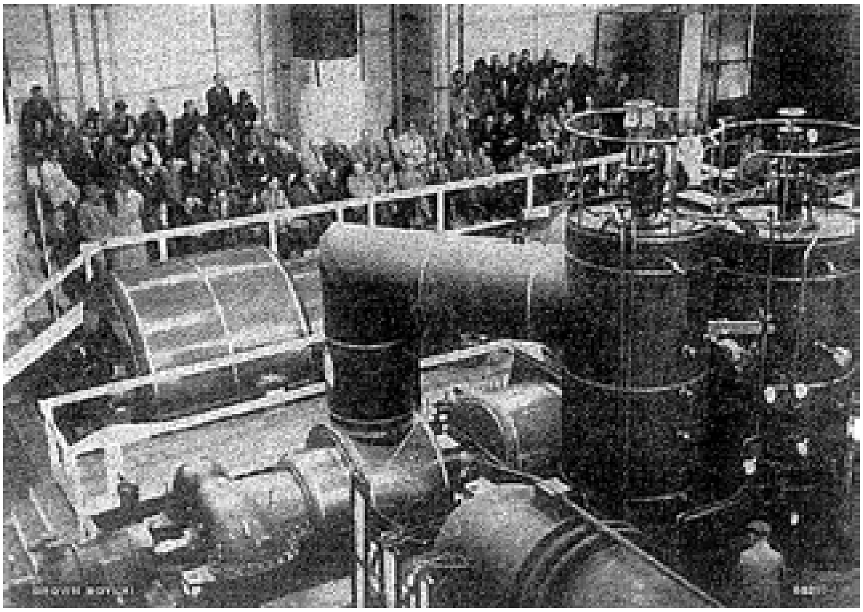
The Romanian unit demonstrated the rapid development of gas-turbine technology, even with hot-gas-path materials limited to 1112F and turbine inlet temperatures of 1070F (less than the exhaust temperatures of some modern machines). Pressure ratios were low compared to those achievable today, but the intercooled turbines had higher efficiencies than some modern engines with cooled turbine stages.

The Romanian success story was soon followed by a 40-MW powerplant in Beznau, Switzerland, with one 13-MW and one 27-MW engine operating on crude oil and optimized to achieve smokeless combustion. The engines in this plant, the world's largest generating station incorporating gas turbines, featured recuperators and sequential combustion, in addition to intercooling.

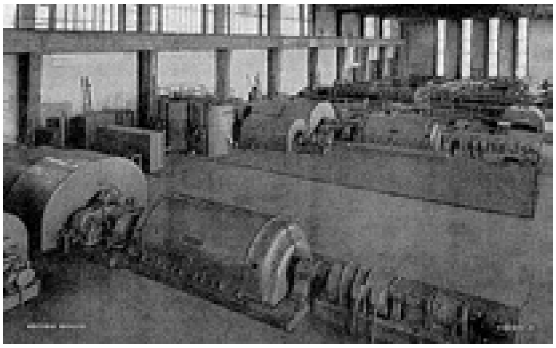
Port Mann was the next step forward. Having units controlled from corporate headquarters was important for a utility trying to reduce head count because of salaries viewed by management as high. Here's how this was achieved in an era of electrohydraulic controls and mechanical relays:

A directional radio link was installed from downtown Vancouver to a substation about 13 miles away and transmitted by high-frequency impulses on a high-voltage power line to the Port Mann substation. From there, the impulses were relayed in the same manner to the Port Mann generating station about 10 miles from the substation on the banks of the Frazer River.

Lessons learned on this project contributed significantly to the continued development of gas-turbine technology for power generation. They included::



3. Full factory test of the Bucharest intercooled reheat gas turbine attracted all the engineering dignitaries of the time



4. Korneuburg A, the first combined cycle, which was equipped with intercooled gas turbines, remained in commercial service from 1961 to 1974

- The single-burner combustor design resulted in a visible exhaust plume. Use of a basic water injection system reduced NO_x emissions and controlled the plume.
- Retrofit of an automatic overrunning clutch permitted faster power dispatch from the synchronous condenser mode of operation.
- A 1977 plant report mentioned two bent R1 compressor blades. The assumed cause was inlet icing. Subsequent tests showed ice formation and shedding into the compressor at 35F and 100% humidity. A similar compressor failure seven years earlier probably was caused by icing as well. Icing continues to be a condition of concern and can occur at ambient temperatures in the 40s. For more information, go to www.ccj-online.com and type "compressor icing" into the search-function box.

"The search for higher efficiency and output, which motivated the early developments in intercooling, also was a driver for the first combined cycle, Korneuburg A, installed in 1961," van der Linden continued. The 2 × 1 Austrian plant was equipped with two 25-MW intercooled gas turbines and one 25-MW steam turbine. The 26%-efficient GTs produced a relatively cool exhaust stream (590F), resulting in low-quality steam. A fired superheater raised steam temperature to 824F, boosting overall plant efficiency to 32%.

Van der Linden recalled that the plant ran successfully until 1974 when high fuel prices made it uneconomic. It was replaced by Korneuburg B, a 125-MW 1 × 1 combined cycle, powered by a single-shaft, 81-MW gas turbine. This plant was the most efficient powerplant ever commissioned when it went into service in 1981. "The race was on," van der Linden said, "for improved cycle efficiency with ever-increasing turbine inlet temperatures, pressure ratios, and GT sizes."

Closing, the consultant added, "The displacement of two-shaft intercooled reheat machines by a lower-cost single large gas turbine with co-axial shafts, two compressors and turbines, a single annular combustor, and substantially higher efficiency was a truly remarkable development." CCJ

Acknowledgement. Historical sources include published papers and various editions of the *Brown Boveri Review* in addition to personal communication with Dietrich Eckhardt. To dig deeper, see ASME's *Journal of Engineering for Gas Turbines and Power,* July 2002.

Your circ-water piping: Is it a disaster waiting to happen?

By Thomas F Armistead, Consulting Editor

A circulating-water pipe failed at Unit 3 of Southwestern Public Service Co's Harrington Station, Amarillo, Tex, late last October. No one was injured because the failure occurred in the evening, and the maintenance crew was gone, but the breached pipe flooded the basement with 3 in. of water and damaged the electrical circuit breakers. It forced all three units of the 1066-MW coal-fired powerplant to shut down because they share the basement.

The company declined to release the damage estimate, but it will be "a few million" dollars, said David Low, general manager of generation in Texas and New Mexico for Xcel Energy, SPS's parent company. All three units were returned to service at the end of December.

Out of sight and out of mind, circulating-water pipe is easy to overlook in planning for maintenance during a scheduled outage. "The circulating-water system is the simplest critical system in the powerplant," said John M Brodar, PE, mechanical/corrosion engineer at Salt River Project, Tempe, Ariz. But he emphasizes "critical."

To Brodar, "critical" describes any component of a powerplant system that can interfere with the plant's only function, which is producing megawatts. If a large, reputable, investor-owned utility can be blindsided by a failure of its circ-water system, every powerplant owner in the US should heed the warning.

Most critical powerplant systems—the fuel system, gas turbine, HRSG, and others—are much more complex than the circ-water system, which consists of piping, the condenser, and the cooling tower, with few moving parts to break down. These form a cooling loop, drawing water out of the cooling tower to the condenser, then returning it to the top of the cooling tower. Pressure is low, typically less than 50 psig. "Because there are so few problems, it's easy to ignore it, forget about it," Brodar said.

1. When prestressed concrete cylinder pipe fails, it often does so catastrophically

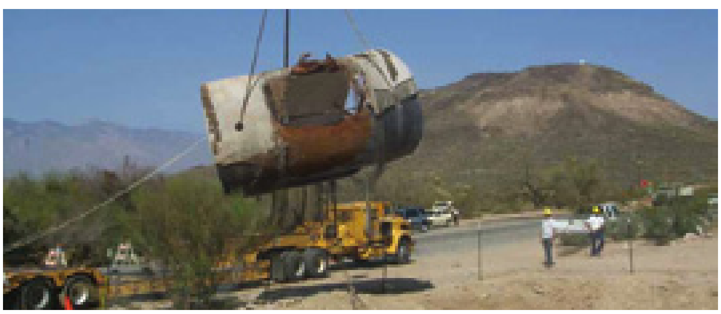
Threat and counterthreat

If the system is simple, and its problems are few, what should you be worrying about? You're probably already maintaining the above-ground parts, the condenser and the cooling tower, but when did you last inspect and maintain the piping? The principal threats to the circulating-water pipe are physical damage during transport and installation, overburden loading on buried pipe, and corrosion.

Most circ-water pipe is made of steel, concrete, or plastic: fiber-reinforced plastic (FRP) or high-density polyethylene (HDPE). Each material has its strengths and weaknesses, which determine the applications for which they are used.

Point loading from surface live loads is a threat to buried pipe that can too easily be overlooked once the pipe is out of sight underground, and the various types of pipe differ in their ability to handle pressure. Steel, FRP, and HDPE handle internal pressure well, but not external pressure, especially when the pipe is empty or unpressurized. Concrete, on the other hand, is strong for external loads but easily overpressurized.

It is important to keep these characteristics in mind when designing buried piping that passes under driveways in a powerplant, for exam-



2. Trailing prestressing wires, the pipe displays hole blown by internal pressure (above)

3. Prestressing wires contain pressure; the steel can is mostly a water barrier. Failure occurred because corrosion attacked the wires. When the pressure is no longer contained, the pipe blows out (right) ple, because extremely heavy equipment, such as transformers and turbines, must be delivered via road to the plant. If you're unaware or forget that the pipe is under the road, the ultra-heavy load can damage it. Good design will anticipate that. "Where roads cross buried pipe, you can cause big problems to empty, unpressurized pipe during an outage if you drive a load over the buried pipe," said Brodar.

HDPE is probably the most trouble-free material of all, "almost indestructible," said Brodar. It is easily fabricated using automated welding fixtures to complete nearly perfect butt welds, which actually are stronger than the rest of the pipe. In 2008, the Nuclear Regulatory Commission endorsed the material's reliability when it approved HDPE for safety-related water pipe, a first for the industry. And plastic pipe generally resists corrosion because it is chemically inert, Brodar said.

But thermal expansion can harm plastic pipes because the material has a high coefficient of thermal expansion, meaning that a thermal change will result in a higher axial displacement for plastic than for metal pipe. Water temperature above 150F in plastic pipe also could pose a threat. Extremely low ambient temperatures may cause hard thermoplastic materials to become brittle. FRP expansion, however, is less than HDPE's. The strength, rigidity, and surface hardness of plastic pipe are inferior to steel pipe's properties.

Plastic pipe is vulnerable to collapse caused by a vacuum, which can result from siphoning. Large FRP circ-water lines require wall ribbing, vacuum relief, or specific operating procedures to counter this threat.

As noted, plastic pipe resists corrosion, but FRP is not entirely immune, according to the National Association of Corrosion Engineers International, because of the way NACE defines corrosion. FRP has a gel coat for chemical resistance and water resistance, but if the gel coat is damaged, the glass fibers become exposed, and the water will wick along the fibers for a substantial distance (6-12 in.), weakening the bond between the fibers and the epoxy, and thus weakening the pipe, Brodar said.

It's not corrosion of metal, but meets NACE's definition of corrosion as "the deterioration of a substance, (usually a metal) or its properties because of a reaction with its environment." From the outside, the pipe looks undamaged, but the effect is to weaken the pipe. In addition, FRP is brittle and vulnerable to pinpoint pressure. So, for FRP pipe that is buried, "bedding is incredibly important," said Brodar. The bedding material must be entirely free of rocks.

Prestressed concrete cylinder pipe (PCCP) also is brittle, but it compensates with massive strength. It is a good choice for burial under railroads and roads that will carry heavy loads. Bedding requires less attention than plastic pipe's because concrete is not as vulnerable to pinpoint pressure, and vacuum-caused collapse is not a threat.

The alkaline nature of the cement mortar protects the steel prestressing wires from corrosion, making the steel passive by shifting its pH well above 11, said Brodar. A crack in the coating, however, puts this type of pipe at risk by exposing the bare steel, making it the anode and accelerating corrosion. If that happens, PCCP can fail catastrophically, he said (Figs 1-3).

Uncoated steel and HDPE pipes are not vulnerable to pinpoint pressure, but corrosion can attack steel pipe both inside and out, said Brodar. Fusion-bonded epoxy, coal-tar enamel, polyethylene, or vinyl tape wrap will protect steel pipe against exterior corrosion, but these coatings also are susceptible to pinpoint damage, so the bedding for coated steel pipe should be similar to that for FRP. Bedding for both should be rock-free clean sand or screened native soil, but above the springline,

1. What causes corrosion?

Man's struggle with nature is so much a fact of life that it is a cliché. Overlooked is the fact that Mother Nature is a sore loser. She may retreat after a battle, but she never gives up on the war. That's the reality behind the phenomenon known as corrosion.

A steel pipe is the product of manufacturing processes that use energy to convert iron ore into steel. Nature yields the ore to the miner, but once the pipe is fabricated, chemicals in its environment react with the material, and it begins to return to its natural condition as iron ore. Unchecked, the process of corrosion will end in the destruction of the steel. The energy that was stored in the steel during manufacture is released as electric energy that accompanies the chemical changes. Thus, corrosion is an electrochemical process, a combination of chemical reaction and electric energy.

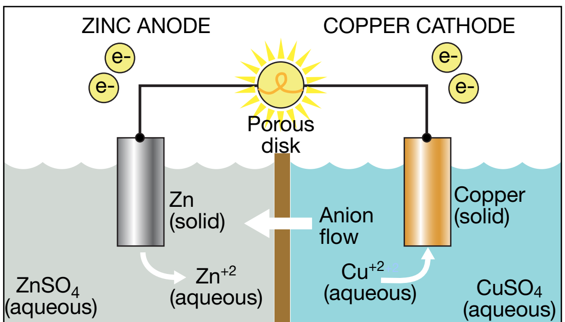
Corrosion occurs in an electric circuit known as a galvanic cell (Fig A), which consists of a cathode, an anode, a conductive path between them, and an electrolyte. An automobile battery is a galvanic cell in which the electrochemical reaction is harnessed to produce electricity: The negative terminal, a metal, is the cathode; the positive terminal, a different metal, is the anode, and the battery acid is the electrolyte.

When the anode reacts with the electrolyte, it releases particles of its metal in the form of positively charged ions, leaving behind negatively charged free electrons. The ions flow through the electrolyte to the cathode, building a net-positive charge. The difference in potential drives the free electrons from anode to cathode, generating electric current.

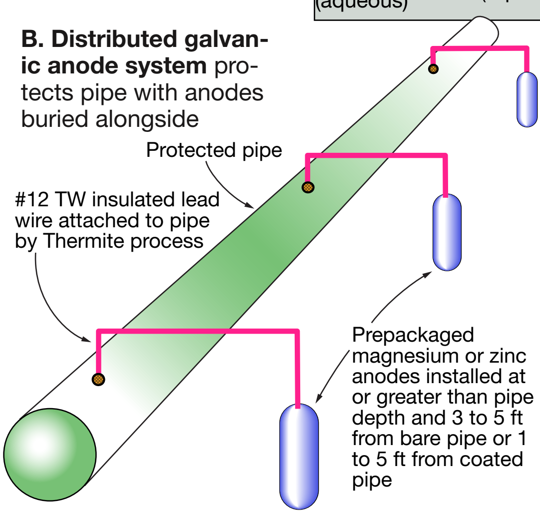
In the automobile battery, the electrolyte is dilute sulfuric acid, but other materials can also be electrolytes. Water is the most common. For a buried steel pipe, the soil in which it is embedded plays the role of the electrolyte. If there is a moisture difference or two different soil types are in contact with the pipe, anodes and cathodes will form on the pipe. In that case, corrosion occurs because the pipe is in contact with two dissimilar electrodes, and the pipe itself acts as the anode, the cathode, and the conductor.

"Corrosion is caused by differences," said John Brodar. In a powerplant's circulating-water cooling system, the pipes are made of coated steel and they come in contact with other materials, including soil, concrete, steel encased in concrete, copper, and stainless steel on the exterior side. On the interior, the steel material may be in contact with copper or brass condenser materials, stainless steel, and chemicals in the cooling water. The potential for corrosion exists wherever two dissimilar metals are joined in a galvanic couple.

A. Corrosion occurs in an electric circuit known as a galvanic cell, which has these elements: cathode, anode, conductive path between anode and cathode, and an electrolyte



B. Distributed galvanic anode system protects pipe with anodes buried alongside



Metals are sorted in the galvanic series (table) according to the difference in potential between them, measured in volts. At the anodic end, with the highest negative charge, are magnesium, zinc, and galvanized steel. At the cathodic end, with the highest positive charge, are platinum, gold, and graphite (carbon). The anodic end of the series is called the active end and the cathodic the noble or passive end because the the anode releases ions and the

Galvanic series

The following is a galvanic series of metals exposed to seawater. When any two metals are connected in a galvanic cell, the corrosion of the one higher in the galvanic series is accelerated while the corrosion of the one lower in the galvanic series is reduced or stopped.

ACTIVE END (–)

Magnesium
Magnesium alloys
Zinc
Galvanized steel

Aluminum 1100

Aluminum 6053
Alclad

Cadmium

Aluminum 2024 (4.5 Cu, 1.5 Mg, 0.6 Mn)

Mild steel
Wrought iron
Cast iron

13%-chromium stainless steel, Type 410 (active)
18-8 stainless steel, Type 304 (active)
18-12-3 stainless steel, Type 316 (active)

Lead-tin solders
Lead
Tin

Muntz metal
Manganese bronze
Naval brass

Nickel (active)
76 Ni-16 Cr-7 Fe alloy (active)

60 Ni-30 Mo-6 Fe-4 Mn

Yellow brass
Admiralty brass
Aluminum brass
Red brass
Copper
Silicon bronze

70-30 Copper/nickel
G-bronze
M-bronze
Silver solder
Nickel (passive)
76 Ni-16 Cr-7 Fe alloy (passive)
67 Ni-33 Cu alloy (Monel)
13%-chromium stainless steel, Type 410 (passive)
Titanium

18-8 stainless steel, Type 410 (passive)
18-12-3 stainless steel, Type 316 (passive)

Silver

Graphite
Gold
Platinum

PASSIVE END (+)

cathode receives them. Most important is the fact that the anode corrodes while the corrosion resistance of the cathode increases.

Corrosion depletes or corrodes the anode, which is the metal closer to the active end of any galvanic couple in the series. Iron and steel carry a lower negative charge than zinc, so pairing a steel pipe in an electrolyte with a zinc anode will protect the pipe while allowing the zinc anode to corrode (Fig B). The rate of corrosion in the anode can be reduced if the anode and cathode are close neighbors in the galvanic series, with only a small potential difference between them.

The foregoing presents only the basic principles behind corrosion. In a pipe buried in the ground or immersed in water, corrosion will occur in a variety of ways, all based on these principles. For example, a steel pipe with a brass fitting or valve will form a galvanic cell even in uniform embedment soil if the soil is moist, because of the difference in potential between steel and brass. You will find a 10-page description of corrosion basics at http://www.npl.co.uk/upload/pdf/beginners_guide_to_corrosion.pdf, one module of the comprehensive website http://corrosion-doctors.org.

the backfill for both can be rock-free, graded native soil.

Corrosion

Uniformity in the embedment is necessary because "corrosion is due to differences," Brodar explained. The presence of different materials around a pipe creates a galvanic cell (Sidebar 1). A cell cannot affect plastic pipe, but it will corrode unprotected steel. The source of the sand also matters with steel-pipe embedment. "If you use beach sand, you introduce chlorides, and that will create problems," said Brodar. Slag and mine tailings provide bedding as good as sand for compaction, but bad chemistry, with resulting corrosion. Cathodic protection is required to prevent corrosion of buried steel pipe by galvanic action.

A cathode and an anode in an electrolyte with a metal path connecting the poles create a galvanic cell. For buried pipe, a difference in embedment materials can cause anodes and cathodes to form on the same piece of pipe. Cathodic protection doesn't stop corrosion, it just transfers it to the anode, whose only function is to corrode (Sidebar 2).

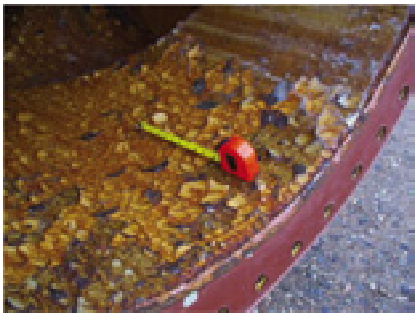
The coating on the pipe isolates it from the electrolyte, but if pinholes exist in the coating, the pipe will become anodic and corrosion will occur at the pinhole. For exterior corrosion protection, coatings and cathodic protection are synergistic, said Brodar. They are more effective together than either is alone.

Uniformity of embedment material is no guarantee against galvanic corrosion, however. Pipe that is buried in soil or partially immersed in groundwater is susceptible to corrosion, and near the ocean, saltwater intrusion creates other corrosion problems. Landfills also produce corrosive liquids.

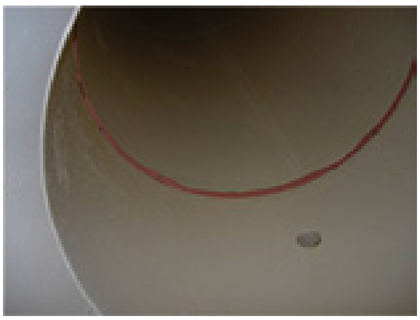
Powerplant designers must take these environmental conditions into consideration when they design buried piping, whether for circ-water systems or other purposes. If you are unsure whether your buried pipes were designed with this in mind, or you have other reasons for thinking they may be at risk, now would be a good time to inspect them and make certain of their condition.

Inside the pipe, there are other potential sources of corrosion. Plastic pipe is chemically inactive, so it's immune. Concrete pipe's corrosion depends upon the pH of the water: If it's high enough, the pipe can be unaffected for decades; if not, "the concrete can be very rapidly attacked," said Brodar. The attack can destroy the pipe. "If normal pH

4. Cooling-tower riser was found seriously corroded upon inspection



5. Epoxy coating of the riser in Fig 4 was heavily contaminated



6. Chemical decontamination of the riser in Fig 4 with a low-pressure water wash prepared it for re-coating. After three years in service, the coating still was pristine. Decontamination before coating was the key

2. Protecting the pipe you can't see

Corrosion occurs when ions flow from an anode into the electrolyte. Every corrosion cell has four elements: an anode, a cathode, an electrolyte, and a metallic path (Sidebar 1). Cathodic protection does not stop corrosion; it transfers corrosion to a specific structure known as a cathodic protection anode. Cathodic protection works by changing the protected structure (the circulating-water line) from being the natural anode (corroding) to a cathode free of corrosion.

This change from anode to cathode is caused by direct-current flow. With a directed electric current flow, from the cathodic protection anode to the protected structure in the electrolyte, corrosion on the circulating-water line will be reduced and, with sufficient current, it will be stopped entirely.

Cathodic protection works by connecting an anodic metal to the steel pipe and allowing a direct current to flow between them. The effectiveness of cathodic protection is measured by the potential (voltage) of the protected structure compared to a reference electrode. The pipe is one-half of a galvanic cell; a "reference cell" is the other half. When they are connected through a voltmeter, they make a complete battery, whose voltage can be measured.

Electric potential is idiosyncratic: Every galvanic couple has its own, so the National Association of Corrosion Engineers (NACE) criterion for protection is that if steel is more negative than –0.850 V relative to a copper/copper sulfate cell, it is completely protected and will not corrode. The Cu/CuSO4 cell thus is the reference cell for the NACE standard, a yardstick for measuring corrosion protection that can be applied to other couples.

In a cathodic protection system, an anode of zinc typically is buried near the steel pipe and backfilled with bentonite clay, calcium sulfate, and sodium sulfate. The potential is checked by connecting a lead from the pipe to the red wire on the voltmeter and a lead from the reference cell to the black wire. If the potential of the protected structure is more negative than –0.850 V relative to the $Cu/CuSO_4$ reference electrode, it will not corrode.

Coatings and cathodic protection work synergistically. The coating does most of the corrosion control, and cathodic protection provides the corrosion protection at the flaws in the coating. Without cathodic protection, the structure will corrode at the flaw. It is cheaper to protect most of the surface of the pipe with coating, which reduces the amount of current required for cathodic protection. Corrosion will be halted as long as the cathodic protection system is maintained such that the protected structure potential is more negative than –0.850 V.

The anode's sole function is to sacrifice itself and provide protective current. Over time, it will corrode and the dc flow will have to be increased to maintain protection. Periodic inspections by close-interval survey can confirm the protection by measuring the potential and confirming it meets the criteria over the length of the pipe. A close-interval survey normally checks protection about every five feet.

Generally, when a lot of current is required in a single location it is more economical to use an impressed-current system instead of galvanic anode. The impressed-current system supplies direct current from an outside source called a transformer rectifier, but the description of the sacrificial-anode system suffices to explain the principles behind this form of cathodic protection.

is less than 8, the situation should be further evaluated," he said. "Any pH excursion into the acidic range will cause permanent attack on the concrete pipe."

Coated steel pipe will handle a broader pH range than concrete, depending on the interior coating, said Brodar. "Most epoxies can handle long-term exposures to from neutral (7 pH) to highly alkaline conditions. Excursions to a pH of 5 or even 4 should not cause major concerns," he added. But if the coating is damaged, the pipe is even more susceptible to corrosion than concrete (Fig 4). "If a significant pH excursion has occurred, say, from a sulfuric acid addition error, expect every coating defect to become heavily contaminated with sulfates," he said (Fig 5).

"Chemical decontamination with low-pressure water cleaning at 3500 psig minimum using a zero-degree rotating tip should be performed at the next outage on every coating defect," followed by touch-up of the affected areas (Fig 6). "Cathodic protection can and will protect the exterior from corrosion if the CP system itself is maintained. Interior coatings can be maintained on pipe larger than 54 in.," he added, "but below 54 in., access with blasting equipment is very difficult."

Microbiological deposits can be a significant threat to the interior of a circ-water line because they greatly increase the corrosion. As the microbes grow, they form a gelatinous mass that isolates the microbe colony from the general environment. Some of these microbes will feed on the sulfates in the circulating water. The waste product is sulfuric acid, which will rapidly attack the steel.

Seawater corrosion on steel is typically about 5 mils per year, said Brodar, but he has seen corrosion from microbiological deposits as high as 50-75 mils per year. This is a key change in the corrosion rate from decades past. He says it appears to be concurrent with the change in recent years from liquid chlorine to other biocides in circ-water systems. That change has occurred because liquid chlorine is difficult to handle.

The change in the last 10 years has been "dramatic," Brodar said. For the first time ever, for example, he has seen through-wall pits at SRP's 2409-MW Navajo Generating Station in Page, Ariz. On a recent inspection he saw a pit deeper than 325 mils, and he found 25 to 30 through-wall pits. With the latter, he noted, it's impossible to say whether the corrosion originated inside the pipe or outside because the corrosion walls are perpendicular to the pipe wall.

The source of water in a circulating-water system makes a difference, Brodar said. Seawater is a known corrosion agent that coatings counteract. Fresh water is not nearly as corrosive in a once-through cooling system, but for a cooling tower, as cycles are increased, corrosion problems grow with concentration.

As in real estate, location also matters. East of the Mississippi, water tends to be acidic, west of it, alkaline. The use of industrial and municipal effluent in cooling-system makeup water also may result in increased corrosion because the micro-organisms that create biofilm feed on the nitrogen, phosphate, and organic compounds in the effluent.

Macrobiological organisms, principally zebra mussels and quagga mussels, also threaten circ-water systems. Their larvae are microscopically small, less than 200 microns, and can't be filtered out of cooling water before they attach to the circ-water pipes and form colonies that grow and block the pipes. Condenser tubes or condenser inlets are ideal locations for these colonies. Even before they are large enough to block the pipes, mussels interfere with cooling-water flow and allow sediment buildup.

Powerplants in Europe deal with the mussels by having two identical circ-water system intakes so they can shut down one for cleaning while using the spare for continuing operation, Brodar said. The mussels are not yet a problem in SRP's system, but he wondered why operators don't backwash with hot water to kill the organisms. Temperatures over 120F halt biofouling, he said.

Even intact, uncorroded pipe can be threatened by leaks from pipe joints. Bell-and-spigot joints are used for concrete and FRP piping, and the American Water Works Association allows some leakage, Brodar noted. But you need to pay attention to the allowable leakage, he added. Soils will have different drainage characteristics. Joint leakage that could be acceptable in well-draining soils may become problematic in clayey soils. EPC contractors like to use packaged designs, and may overlook factors that will be important to your pipe. "Make sure the EPC addresses the soil conditions at your facility for his canned design," he said.

Inspection, maintenance

Like other powerplant systems, circulating-water pipes require regular inspection and maintenance, but this requirement is often overlooked. A visual inspection of the cleaned interior coated surface is the first requirement. Any flaw in the coating requires further investigation.

All of the traditional nondestructive examination techniques can be used for steel circ-water systems, including ultrasound, magnetic particle, and liquid-penetrant inspection of steel to detect cracks. Radiographic inspection is generally not considered because it requires access from both sides of the pipe wall, and buried pipes are accessible only from the interior. For fiber-reinforced plastic, inspection is mainly a matter of looking for blisters, Brodar said.

7. Inspecting a cooling-tower riser with a low-voltage holiday test is relatively easy inside pipes 54 in. and larger; more difficult in smaller pipes

8. A 0-deg rotating jet's spray pattern is visible where it was moved rapidly over the surface. More complete cleaning is evident at lower right

9. A test paper impregnated with potassium ferrocyanide placed on the exposed steel indicates with its blue color change that the contamination is from nonvisible soluble salts

Until fairly recently, the only way to inspect prestressed concrete cylinder pipe was by visual inspection or sounding—tapping the surface with an inspection hammer. Good concrete sounds solid when struck, and the hammer rebounds readily. Disbonded or weak concrete, on the other hand, gives a dull sound, a "thud." Brodar now recommends a baseline remote-field eddy current (RFEC) for inspection on all critical PCCP. If the baseline survey identifies damaged reinforcing wires, then periodic follow-up surveys are required.

The eddy current send-receive probe technique is a screening tool, said Tom Burnett, power group director with Intertek Aptech, Houston, the contractor that inspected Southwestern Public Service's Harrington Station after its circ-water pipe failed. The technique uses variations in the strength of magnetic waves shot through metal to identify locations of possible corrosion for visual inspection.

Brodar likes RFEC because it locates corrosion in the prestressing wires in PCCP. Aptech used pulsed eddy current testing at Harrington because the failed pipe was carbon steel, and PEC "can test relatively large areas without significant preparation, and provide a good screening evaluation of wall loss in ferritic steels," says an Aptech report.

The exterior of buried circulating-water lines cannot be inspected without excavation. Because of this it is essential to maintain the cathodic protection system for the exterior of the lines. A simple close-interval potential survey is the easiest way to confirm adequate cathodic protection.

The interior is another story. Pipe size and length are the factors here. Pipe diameter affects inspection and maintenance mainly because, "if you can't stand up in the pipe, it's a real challenge to perform inspections and especially coating maintenance," said Brodar (Fig 7). On a long pipe, manholes must be spaced so that hoses and cables will allow the workers to reach the midpoint between them.

Brodar has cleaning contractors work in both directions from a single manhole during a turnaround, while limiting the scope of work to a reasonable length of pipeline for each outage. Work during the next outage then will begin at an adjacent manhole. Because of the difficulty of access he limits the amount of maintenance work to what is reasonably achievable in the outage period.

The principle that rules large-diameter underground pipe maintenance is, "Whatever goes into the manhole has to come back out," said Brodar. If the sandblasting operation uses 40 tons of sand, that's 40 tons that must be removed at the end. Instead of hauling out buckets of sand through a manhole, he has had "phenomenal success" using a vacuum truck to clean out the sand. Sandblasting also requires "dragging a big, fat hose with fittings and ears across thin-film paint," causing the invert, or floor of the pipe, to be in worse condition after the cleaning than before, he said.

Brodar prefers cleaning pipe interiors with ultra-high-pressure water jetting (above 25,000 psig) or low-pressure water cleaning (between 3500 and 5000 psig), depending upon the size and scope of the job. Both types of water cleaning require the use of a rotating tip for production rates and chemical decontamination to remove chlorides and sulfates.

Once corrosion has started, it will continue to attack the same locations on a steel pipe's interior, no matter how many times it is cleaned and repainted, said Brodar. That is because interior corrosion is caused by nonvisible soluble salts, which react with the steel, oxidizing it.

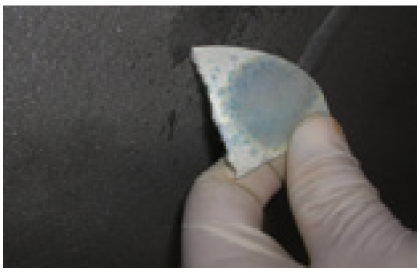
Nonvisible soluble salts are primarily chlorides and sulfates. The chloride buildup occurs in circ-water systems because the water becomes concentrated over many cycles. Sulfates (SO_4) build up because sulfuric acid (H_2SO_4) is added to control the pH of the circulating water. These salts are driven to the anode—the steel pipe—promoting corrosion.

This surface-contamination phenomenon is the largest problem facing paint in the 21st century, said Brodar, because we can no longer use lead-based paints for corrosion protection. The lead stops the corrosion induced by nonvisible salts by bonding with chloride.

Today's immersion paints are barrier coatings, not inhibitive coatings. Instead of relying on the paint to inhibit corrosion, engineers now must ensure complete removal of the salts before painting. It's more work, but it can be done.

Blast cleaning to white metal clears the obvious corrosion, but it also embeds many of the contaminants in the steel, Brodar said. If that occurs, flash rusting is inevitable, even after dry blasting. High humidity alone will not trigger flash rusting on an uncontaminated blasted surface; direct water contact is necessary for that to happen. But a blast-cleaned surface with trace contamination of soluble ions will flash-rust because the ions are hygroscopic, meaning they absorb moisture from the air.

Brodar prefers to pressure-wash with Chlor-Rid, a chemical decontaminant that removes soluble salts, using a zero-degree rotating tip that sprays a thin jet of water in a circle at 3500 psig. Pressure-washing is often done with a fan tip, which cleans broadly but not deeply into pits, he said. It is effective for the still coated, uncorroded surfaces, but it leaves traces of the soluble salts in the pits, and rust will reappear, often within minutes. When the rotating jet, on the other hand, is moved slowly over the surface, it cleans deeply, leaving a characteristic pattern, and the salts are completely removed (Fig 8).



10. The cleaned steel looks like white metal, but blue spots show that it's still contaminated. If painted over, it will fail well before the next inspection in three years

11. A bifurcate in the circ-water line, stripped of all coating and decontaminated with a chemical wash, still is covered with iron oxide. The light brown color is "nice clean rust," said Brodar. Deep brown to black color would indicate contaminants, requiring further cleaning

Brodar tests steel for contamination with a small sheet of lab paper or filter paper impregnated with a solution of 4 milligrams of potassium ferrocyanide in 100 mg of water, which he prepares himself. It dries with a bright yellow color. He wets the spot to be tested, then presses the paper on it. If it turns blue, the surface is contaminated with chloride or sulfate (Fig 9). Tests after cleaning reveal spots where the salts remain (Fig 10). In that case, cleaning continues until there is no blue on the paper.

Removing nonvisible soluble salts is more important than removing all rust, Brodar said (Fig 11). A steel surface with light-brown rust can be painted over as long as there are no darker spots (Fig 12).

People who can do quality work inspecting circulating-water pipes are a subset of qualified powerplant inspectors, said Brodar. They have to be able to handle confined spaces, heights, and darkness without fear. The old rule is, "If you're going to a powerplant, you should have a flashlight," he said. "If you're going someplace dark in a powerplant, you should have three or four flashlights." His inspectors now use LED lights affixed to hard hats, which Brodar calls "a phenomenal improvement over the old stuff" (Fig 13).

Brodar's approach to inspecting pipe is thorough, but pragmatic. He doesn't look for problems in the finish or coating where they are not readily visible because he figures that coat-

12. Proof of effective decontamination is time in service. After three years, the pipe from Fig 11 shows no corrosion

13. Brodar models the kit of a modern pipe inspector

14, 15. Coal-tar enamel coating was removed where it had failed, then repaired with penetrating primer to seal the edge of the enamel, plus two coats of surface-tolerant epoxy. Feathering the enamel to 45 deg, a standard industry practice, was not required (left). After six years in service (right), it is clear that the repair was successful, except for a small area that was not properly prepared and now shows creeping failure. "You can't stop the creeping failure," Brodar said. "It fails a little bit every time it's in service. The best you can do is to find a quick, easy, and economical repair," such as that shown above the recently failed area

ing adhesion is thoroughly tested in service (Fig 14). Besides, he said, adhesion is not the main thing; after a system has been in service, the problem areas are identified: they are corroding (Fig 15). The key is to clean up chlorides and sulfates at the corroded sites, because they are the cause of corrosion. In FRP or fiberglass pipe, he looks for bulging, cracks, or chips. If you push on a spot and find it soft, he said, you have a mechanical-strength problem and you will need a fiberglass expert to solve it.

For steel pipe, if the diameter-to-thickness ratio is greater than 108 ($D/t > 108$), the pipe is susceptible to collapse from either vacuum or external load. Wall thickness in steel pipe determines its structural strength, of course, and one of the best defenses against failure caused by corrosion is thicker pipe walls. But thicker walls cost more money, so the economic reality is to design and install steel pipe just thick enough to handle the pressure.

However, it is not necessary to double the steel-plate thickness to double its time-to-failure by pitting. Applying the "cubed-root law" when designing pipes determines how much increased pipe thickness can extend service life, Brodar said. If a pit would fully penetrate a pipe wall with thickness t in five years, then doubling the wall thickness would extend the service life $2^3t \times 5$ ($8t \times 5$) years for an expected life of 40t years. Increasing the wall thickness 25% would almost double the expected service life $1.25^3t \times 5$ ($1.95t \times 5$) years to 10 years.

The failure at Southwestern Public Service's Harrington Station Unit 3, mentioned at the start of this article, illustrates these calculations. The failure occurred in a mastic-coated, unlined, 32-in. pipe at the top of the inspection riser buried under a 6- to 8-in. concrete slab and a couple of feet deep in compacted sand.

The pipe, in service since 1980, was supposed to be 0.375-in. wall, which would have given it a diameter-to-thickness ratio of 85.33, but it was found to be actually 0.1875 in. With a D/t ratio of 170.67, the pipe's 30-yr service life without collapse is remarkable in itself. The pipe failed because its mastic coating failed, but "had it been design spec, it probably would have lasted a few more years," said Xcel's David Low.

The cubed-root law for pitting pegs that extension at approximately $2^3t \times 30$ or 240 years. The Harrington failure was caused by general corrosion, not pitting, so the cubed-root formula is not likely to give an accurate prediction of increased time to failure, Brodar said, but it supports the opinion that the originally specified thickness would not have failed in just 30 years.

Xcel Energy is taking the lesson of its circulating-water line failure to heart. In the month following the break, Houston-based Intertek Aptech did a pulsed eddy current inspection of the system, and David Low will have the underground lines coated with 0.25-in. of polymer during the next planned outage.

Inspectors also accessed the interior of the failed riser via ladders for visual inspection and found the interior rough. The pipe is not normally accessible from the outside, so the company did not often inspect the 32-in. line, and the interior was not previously scraped and painted. That maintenance was done as well. "It's a heads-up for all our plants from Minnesota to Colorado to New Mexico," Low said. CCJ

Blending off-spec, pipeline gases reduces fuel cost

By Mike Segers, PE, Hurst Technologies Corp

Four years ago, natural gas and oil prices had gone through the roof. Today, natural gas is lower than it has been in decades. Because of this volatility, fuel flexibility is almost always a good thing, as long as you remain within the range of fuel specifications recommended by the manufacturers of your gas turbines and duct burners.

Good news about fuel flexibility came to the powerplants in the Odessa (Tex) area in June 2010. A pipeline to deliver natural gas directly from the Yates Formation in the Permian Basin was announced. However, the fuel was off-spec, containing high levels of nitrogen (Sidebar 1). Scrubbing out the nitrogen was cost-prohibitive.

But blending it with spec fuel could reduce overall fuel costs and the nitrogen content of the final mixture. At least two plants in the area decided to install fuel blending stations. This article presents the details of the approach used by Plant A, described in Sidebar 2, with some comparison to the approach taken by the other facility (Plant B). Key to success is an analyzer that can determine the composition of the blended fuel in near real time.

Fuel-gas blending at power stations is not new. Typically, one source is placed on flow control, and the second source on pressure control so that (1) as much as possible of the less expensive gas is burned and (2) the amount from one source can be controlled to meet contractual limits, especially take or pay contracts.

However, most plants have not blended fuel gas based on specific gas constituents. Some constituents are difficult to measure in real time, which is necessary for good control in large homogenous volumes. The challenge here was to use a measurement of one of the easier fuel constituents to track—hydrocarbons—to control a more difficult-to-measure constituent, nitrogen.

The gas turbines at these sites are unable to burn 100% Yates Formation fuel. High nitrogen will lead to excessive NO_x emissions. Plus, the large inert fraction has a negative impact on flammability limits. Low flammability ratio makes it difficult to maintain stable combustion across the operating range. Therefore, blending of Yates gas with pipeline-quality gas is necessary to maintain performance within the prescribed range, and still burn as much of the less expensive off-spec fuel as possible.

The fractional analysis of the off-spec gas (Table 1) shows that it is 28% nitrogen, while pipeline gas is 2% nitrogen. If the gas is blended 50:50, the total nitrogen content would be 15%, the upper limit recommended by the turbine manufacturer for these machines (Table 2).

Dealing with nitrogen

Investigation suggested that it is easier to blend based on hydrocarbon content than inert gas, because determining heating value is relatively easy. Several analyzers are available commercially to provide real-time, or nearly so, analysis of hydrocarbon content. At least one gives real-time analog outputs for both Btu content and Wobbe Index. Interestingly, heating value is not the "standard" you may think it is; there is disagreement about the formula used to derive it.

The other issue encountered is the difference between lower and higher heating (calorific) values. The higher heating value is used to calculate

Table 1: Sample fractional analysis of gas from the Yates Formation

Component	Composition, mol %
Nitrogen	28.33
Carbon dioxide	0.05
Methane	56.78
Ethane	8.88
Propane	3.84
Isobutane	0.36
N-butane	1.02
Isopentane	0.20
N-pentane	0.26
Hexanes	0.28

Notes: (1) Calculated specific gravity is 0.789. (2) Calculated heating values in Btu/ft^3 at 14.65 psia/60F are 888 gross wet and 904 gross dry

Table 2: Allowable fuel properties, constituent limits for GE frames

Fuel property	Max	Min
Fuel gas pressure	Varies with unit and combustor type	
Fuel gas temperature		*
LHV, Btu/scf	None	100-300
Modified Wobbe Index		
Absolute limits	54	40
Range within limits	+5%	-5%
Flammability ratio	No defined limit	2.2:1
Constituent limits, mole %		
Methane	100	85
Ethane	15	0
Propane	15	0
Butane and C_4^+	5	0
Hydrogen	Trace	0
Carbon monoxide	Trace	0
Oxygen	Trace	0
Total inerts	15	0

Table is included for general reference only. Consult your OEM representative for additional necessary information
*Min varies with pressure

Wobbe numbers—a/k/a Wobbe Index (WI). The basis for the Wobbe Index is if two fuel gases have identical Wobbe numbers, they will deliver the same amount of heat.

The Wobbe Index is defined as $WI=CV \div SG^{0.5}$, where CV is the calorific value (higher heating value, HHV) of the fuel and SG is the fuel's specific gravity. Heating value is in units of Btu/ft^3.

It is common practice in the electric power industry top use the lower heating value (LHV) when calculating the thermal efficiency of gas-turbine cycles. GE and others use the Modified Wobbe Index (MWI) as a measure of the interchangeability of gaseous fuels for a given system design.

$MWI=LHV \div (SG \times T_{gas})^{0.5}$, where T_{gas} is the absolute temperature of the fuel gas in degrees Rankine. An alternative and easier-to-apply form of this equation is the following: $MWI=LHV \div ((MW_{gas} \div 28.96) \times T_{gas})^{0.5}$, where SG_{gas} is the specific gravity of the fuel gas relative to air, MW_{gas} is the molecular weight of the fuel gas, and 28.96 is the molecular weight of dry air. For more detail, consult GEI 41040G, "Specification for Fuel Gases for Combustion in Heavy-Duty Gas Turbines," which is accessible on the World Wide Web.

Because the Wobbe Index indicates the interchangeability of the fuel gases, it can be used to control blending. Both Wobbe Index and heating value make similar curves, so either can be used to control the nitrogen content of the final blend. The traditional method of controlling the blend, flow control for the off-spec fuel and pressure control for the pipeline gas, is simpler but certainly not the optimum.

Fuel yard versus unit blend station

Two approaches for fuel blending were evaluated: one blend station at the fuel yard and individual blend stations at each gas turbine. Plant B, which has different GE engines than Plant A, opted to install a single blending station in its fuel yard to serve both the gas turbines and duct burners. This facility is equipped with selective catalytic reduction (SCR) units for NO_x control.

Plant A opted for multiple blending systems because it intended to burn the mixed gas only in its turbines and believed the additional operating flexibility offset the higher cost of multiple stations. Plant A personnel saw these advantages of the multiple-blend-station approach:

- While the same model gas turbines are designed to the same specifications, each machine has unique operating characteristics that may require more precise fuel blending. Each unit can be tuned based on operating characteristics, such as fouling or derates caused by vibration, generator limits, balance of plant problems, HRSG problems, or other issues.
- Availability of all units is paramount. Operation of any unit could be limited by combustion instability or NO_x emissions. Individual blending allows any limitation caused by the blending operation to affect only that unit.
- Central blending represents a single point of failure that could force all units to revert to more expensive pipeline quality fuel.
- Self tuning or even neural networks could be employed later to further maximize unit flexibility and operability.

System design

A reliable gas analyzer anchors the blending system design (Fig 1). For this project, COSA Xentaur Instrument Corp's (Yaphank, NY) COSA 9600™ Wobbe Index meter was selected. It has the following features deemed important in this application:

- Provides analog outputs for Btu and Wobbe Index.
- Can analyze multiple streams.
- Can be purged for Class I, Div 2 or Class I, Div 1 applications.
- Has no moving parts.
- Burns flameless (catalytically at 1495F).
- Employs a zirconium oxide oxygen sensor in the oven.

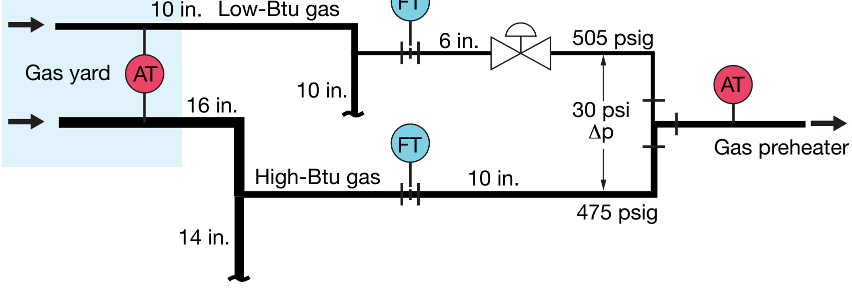
The instrument accepts a sample from a Genie® Probe regulator, man-

1. When fuel is 80% of operating costs

A few years ago, several companies formed a partnership to provide less-expensive fuel for generating electricity in West Texas. The result is a 62-mi pipeline that supplies off-spec gas (high nitrogen content) direct from Permian Basin wells. The fuel, extracted from a depth of about 3000 ft, had been considered uneconomic because the nitrogen would have to be removed before being transported in conventional pipelines. Over 200 old wells drilled to a 4800-ft-deep oil formation are available to produce natural gas from the Yates Formation. The gas-turbine supplier confirmed that the off-spec gas could be burned in its units on a blended basis, making it economical to deliver the fuel to generating plants powered by gas turbines.

2. Plant characteristics

The 1000-MW generating station, which started up in 2001, is comprised of two 2 × 1 combined cycles powered by GE 7FAs equipped with dry low NO_x burners. The four heat-recovery steam generators (HRSGs) have duct burners for supplementary firing. Pipeline-quality gas containing between 1000 and 1025 Btu/scf is supplied from two sources. The fuel passes through a knock-out separator before being sent to the plant. It is preheated to 300F before entering the gas turbines. An Ovation® distributed control system (DCS) from Emerson Process Management integrates the gas and steam turbine control systems for remote start/stop, data monitoring, and data collection. Prior to this project, no gas metering or fuel composition data were taken at the fuel yard or the units.



1. Blending system is designed to accommodate the mixing of off-spec high-nitrogen fuel gas and pipeline quality gas ufactured by A+ Corporation LLC, Gonzales, La, with these benefits:

- Delivers a representative sample.
- Removes all entrained liquids.
- Protects the analyzer against liquid damage.
- Allows probe housing installation in a pressurized line with a foot valve at its base.
- Lets the user define pressure regulation.

In addition to the unit analyzers, a dual-stream analyzer at the fuel yard provides a feed forward signal to the individual blending stations. The analyzers at the discharge of the blending stations are used to bias the blending station for the proper blended fuel introduced to each turbine. The analyzers transmit data to the DCS to control the flow of off-spec gas. All blending- station logic resides in the plant DCS.

Actual blending of the fuel sources is accomplished in a "T" downstream of the off-spec gas flow control valve. In order to properly mix the fuel gases, a 30-psi minimum differential is maintained between the two gas supplies at the blending stations.

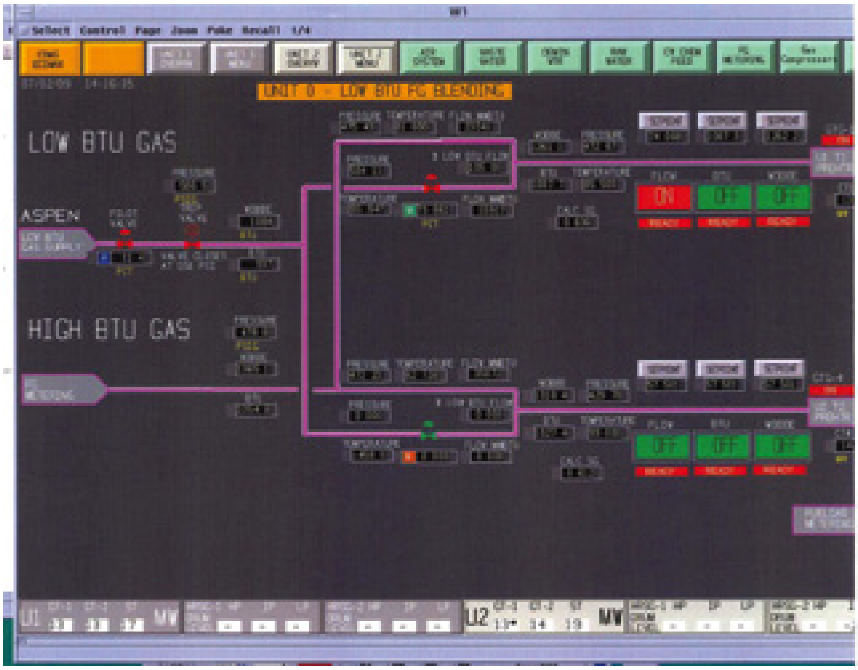
The DCS sends a pressure setpoint signal to a programmable logic controller (PLC) at the fuel yard to control the off-spec gas pressure at the blending station at 30 psi higher than the pressure of the pipeline-quality gas. The arrangement is relatively simple and does not require a valve in the pipeline-gas lines at the blending stations or an elaborate skid arrangement.

Logic, programming

The heating value of pipeline-quality fuel is relatively constant because of the large volume of gas in the line. By the same token, the off-spec gas is expected to be equally consistent in composition because of the size of the formation. One sudden event that should be considered, though, is the possibility of analyzer failure.

As mentioned earlier, nitrogen lowers the rich to lean flammability limits. Flammability ratios of less than 2.2:1, based on volume at standard conditions, may cause unstable combustion over the operating range. While gas turbines can be designed to operate with wide ranging fuel characteristics, the variation of a specific fuel system is usually limited to ±5%.

Fuel nozzles are designed to operate within a fixed range of pressure ratios; changes in heating values are accommodated by increasing or decreasing nozzle area or the fuel gas temperature.



2. Graphics in the control room display give operators all the data necessary to accomplish proper fuel blending

In the event that the turbine control system sends a signal to the DCS indicating poor combustion, the DCS acts to maximize the use of low-cost fuel by first decreasing fuel temperature, then reducing the amount of off-spec fuel.

The maximum ratio of off-spec fuel is 50%, but the minimum limit is set by blending system characteristics. To keep startups trouble-free, only pipeline fuel is used. Once the unit is up and operating reliably at a given load, the operator puts the blending station into service.

If the unit-located analyzer fails, blending is placed on flow control—automatically or manually—and the pipeline gas remains on pressure control. If the fuel yard analyzer fails, the station is automatically placed on flow control for off-spec gas and pressure control for pipeline-quality gas. Analyzer failure does not result in a turbine trip, only the use of more expensive fuel.

Blending-station logic configuration is programmed into the plant DCS. An Allen Bradley PLC (Rockwell Automation Inc, Milwaukee) in the fuel yard interfaces with the DCS to gather data and control blending. Monitoring and control of the blending stations are done through the control room operator interface (HMI). Operators can select heating value, Wobbe Index, or flow as the basis for control. Graphics give the operator a visual presentation of all data related to fuel blending (Fig 2).

Performance

During commissioning, both methods of controlling fuel blending were tested but no differences were identified between the Wobbe Index and heating value. Because the Wobbe Index is incremented in finer divisions, one would expect that finer blending control could be obtained, but for this application, such fine adjustments are not necessary. Off-spec gas on flow control is the default blending control method. This method was also tested, both as an operator-selected operating mode and as a default control mode should one of the analyzers fail.

The plant currently operates in the manual flow-control mode, because the supplier cannot yet provide enough off-spec fuel for continuous blending operations. When the pipeline is packed and the pressure sufficient, the plant puts the blending station in service, typically one day a week. No problems have been reported with the blending station since it went into service. Plant management is pleased with the blending system operation but disappointed with the amount of off-spec fuel available. CCJ

Mike Segers, a professional engineer with over 30 years of I&C experience, managed the fuel blending project for Hurst Technologies Corp. This article was developed from a paper presented at the ISA Power Industry Division's 54th Annual I&C Symposium.

User, vendor technical presentations, safety discussion highlight program

Chairman Russ Snyder, plant manager, Cleco Power LLC, called to order the first user-only technical session at the 2012 meeting of the 501F Users Group on the third day of the conference. He quickly passed the microphone to Vice Chairman Ray Martens, plant manager of the Klamath (Ore) Cogeneration Plant, who led a robust discussion on safety. The second day of the event was spent in closed session with engineers from Siemens Energy, Orlando; the first day focused on vendor presentations.

Over the last several years, personnel safety has grown in importance and today it is the top concern of executives and managers in the electric power industry. Entries received by the editors for this year's Best Practices Awards program (coverage begins on p 19) verify the priority placed on safety today. Five years ago, entries for O&M best practices outnumbered safety entries by more than three to one. This year, there were one-third more entries for safety than there were for O&M.

The **CCJ** archives (www.ccj-online.com/archives) offers a wealth of ideas on the systems and equipment and procedures and administrative methods available for improving plant safety. Reading through the Best Practices entries in every 1Q issue for the last few years is sure to provide the foundation for a successful plant safety program. Several ideas presented in those issues were discussed in Tampa, plus others, of course.

2013 Annual Meeting
March 18 - 21
Westin Charlotte, Charlotte, NC

501F steering committee

Chairman: Russ Snyder, plant manager, Cleco Power LLC
Vice Chairman: Ray Martens, plant manager, Iberdrola Renewables Inc
Vice Chairman: Ivan Kush, director of outage services (Siemens fleet), Calpine Corp
Paul Tegen, chief CT/I&C engineer, Cogentrix Energy Inc
Carey Frost, 501F program manager, Progress Energy
Martha Leskinen, senior engineer, SRP
Paul Terry, rotating equipment reliability engineer, PPG Industries Inc
Rene Villafuerte, plant manager, Comego SA de CV

Fire in the filter house. The subject of the fire risks associated with work on the air inlet house stimulated conversation for perhaps 15 minutes. Far too frequently, there's a report of a fire caused by welding on the filter house; dry air filters and evap media ignite quickly. However, the fire described during Martens' session was caused by a halogen lamp.

Workers hired to change filters were using a halogen lamp in the narrow passageway between the prefilters and conical/cylindrical final filters and forgot to turn off the light before quitting for the day. Exactly how the fire got started is not known; evidence was consumed in the resulting blaze. The person telling the story said the fire department was called at the first sight of smoke but the filter house was a goner in a matter of minutes.

One thought was that the door to the air inlet house, though which the power cord for the lamp passed, closed and moved the lamp in contact with filter material. The job foreman said the door had been tied open, but it was a windy day. The group discussed the incident. One attendee said running a power cord through an open door was an unsafe work practice and should not have been allowed; wall penetrations for utilities should have been installed (see pp 24 and 51).

Another recalled that at least one of the OEMs had issued a safety advisory on lighting inside filter houses that said only low-wattage lighting should be allowed. Someone else suggested the use of LED (light-emitting diode) lighting.

A productive "thread" was underway. Lighting aside, the best observation and thought for the day was that the access door to the three-story filter house was on the first floor and that was the only way to get into and out of the structure. Had a worker been at the second or third elevation (access by wall-mounted ladder) when the fire started, observers said he or she probably could not have survived. The plant is now installing access doors at each level.

Workplace cautions came at a rapid rate as Martens "worked" the room. One person mentioned the fire hazard associated with a borescope light, another talked about the danger of exploding hydraulic lines, yet another about the need for local shutoff switches at each cooling-tower fan.

The subject of roping off restricted areas brought this caution: Be sure to check enclosures within the restricted sector for personnel before marking off the area with "danger" tape. A user remembered a couple of people working in a CEMS house suddenly being trapped in an unsafe area because no one knew they were there. The acronym "CEMS" triggered another safety idea: Install an O_2 sensor in the instrument house that alarms if the oxygen level drops to that needed to just sustain life. This could occur in the unlikely event of leaks from stack and calibration gas lines.

Visible and meaningful labeling was another subject addressed. One person took issue with the way some of his colleagues who had served in the navy labeled access points and components. He suggested that codes, especially those using numbers, might be fine aboard ship but recommended clear wording in shore-side powerplants. Another attendee stressed multiple languages.

NFPA safety standards

Judging from a few questions related to O&M of gas piping systems, it seemed some attendees were unfamiliar with NFPA 56, the new safety standard designed to protect personnel and equipment against explosion and other hazards associated with the use of natural gas. This standard provides minimum safety requirements for the commissioning and maintenance of fuel gas piping—from the point of delivery to the equipment shutoff valve. It is the first such standard applicable to powerplants. To learn more, read "NFPA 56 is a 'game changer'." Access www.ccj-online.com and search on the article title.

To purge or not to purge. A comment from the floor on changes to NFPA 85 that would allow a gas-turbine restart without having to purge the HRSG, thereby saving valuable minutes, got the group buzzing. But no one in the room with in-depth knowledge of the subject stepped up to lead the discussion and no definitive guidance was offered. That was unfortunate because the recent changes to NFPA 85 seem important to deckplates and management personnel alike.

However, the lesson re-learned in Tampa was that plant owners should never underestimate the value of user-group meetings and the "reach" they have. Two days before the 501F users met in closed session there was a presentation by Frank Berte, a member of the management team at Tetra Engineering Group Inc (US office in Weatogue, Ct), covering changes to NFPA 85. During the safety session, the thread on NFPA 85 probably was started by an attendee reaching out for clarification of something he heard from Berte or indirectly from someone who sat in on Berte's session.

But there's more to this story: A plant engineer who was in Tampa and obviously looking for more information on the subject asked, the day after the meeting ended, the following question of participants in the Heat Recovery Steam Generator-HRSG discussion group on Linked-In.com, which just happens to be managed by Peter Jackson of Tetra Engineering: "Anyone scheduled to implement new NFPA rule to avoid HRSG purge on CTG restart?

"I just heard there is a newly published NFPA rule that would permit skipping the mandatory HRSG purge during CTG restart provided (a) methane monitors are installed in the upper HRSG gas space and (b) a triple block-and-bleed [arrangement is] installed in the fuel gas line to the combustors (CTG and duct burner). Skipping this purge on hot restart would avoid forming condensate in the superheaters and reduce damage at the tube-to-header welds, and also shorten the hot restart time. Can anyone advise the new NFPA reference paragraph and advise if they are scheduled to implement the upgrades to allow its use?"

Jackson replied with the content of an informational mailing made at the end of 2011 by Tetra Engineering to its clients and prospects. Here key elements of that material:

- Purge credits. There has been a significant code change affecting startup purge requirements for combined-cycle powerplants. The 2011 edition of NFPA 85, "Boiler and Combustion Systems Hazards Code," now allows operators to credit prior purges if they have implemented positive gas-flow cutoffs and monitoring systems. Purge credits can be maintained for an eight-day period and extended by implementing a purge.
- Who benefits? This will benefit cycling units by allowing them to eliminate purges for many hot and warm starts, thereby (a) resulting in faster startups (improvements of 5 to 15 min), (b) eliminating purge cooling and condensate quenching on superheaters and reheaters, and (c) reducing purge power requirements.
- How to implement. Implementing the purge credit requires minor modifications to gas-turbine and duct-burner fuel lines (additional valving and instrumentation), interconnection with monitoring systems to provide surveillance and annunciation, and procedures to cover the new purge credit requirements.

The plant engineer who initiated this thread did some follow-up research and later provided the online group the following details regarding implementation:

- NFPA 85 (2011), paragraph 8.8.4.6. Triple block and double vent valves on gas turbine and duct-burner fuel lines. Valve positions shall be continuously monitored. Pressures in the block-valve sections shall be continuously monitored. Valves to be validated for leak tightness prior to each startup and following each shutdown.
- Paragraph 4.10.3 provides guidance on a positive means to prevent leakage of ammonia.
- Methane monitors. The plant engineer found no explicit statement on methane monitors but believes they are wise to include.

More on purge credits. A quick call to Amy Sieben, Lester Stanley, and Scott Wambeke of HRST Inc, Eden Prairie, Minn, contributed additional insights for users to consider before making decisions on when to purge. Quick startups are valuable for dispatch sake, the trio acknowledged, but there still should be careful evaluation of the HRSG system to help avoid cycling problems.

Spending money on hardware and controls to achieve a startup purge credit during shutdown doesn't minimize the need to evaluate and install properly sized, located, and controlled superheater and reheater drains, they said. In addition, each HRSG site should evaluate and determine the minimum purge time that meets NFPA requirements. This is important because a trip/restart will still require a purge.

An overnight shutdown will mean a purge during shutdown to achieve the credit, and this purge will still cause condensate to rain down on hot headers. It only takes one bad startup with water trapped in lower headers to cause damage. Sometimes a purge during shutdown can create more condensate in superheaters than a purge during startup—especially if the startup is after HP system pressure has had an opportunity to decrease.

For the shutdown purge, boiler pressure generally is at near full operating pressure. If your current purge is longer than 10 minutes, the three engineers said, a qualified consultant can analyze and often provide a more precise and shorter purge time that still meets NFPA requirements. They concluded the interview essentially with their opening thought: A thorough HRSG cycling study can help sort out your options.

Interestingly, Brian F Craig, PE, of HRST spoke to that subject at the vendor forum early in the week. His thoughts are summarized later in this report.

User presentations

The first of 10 user presenters discussed efforts taken at his plant to minimize offline corrosion. The 2 × 1 501FD2-powered combined cycle is located in a humid area and can be offline for extended periods. A three-pronged approach was implemented. Moving from the air inlet to the stack, here's what was done: Dehumidifiers of the desiccant rotor type were installed in the inlet plenums of both gas turbines; a waterside heater was installed in each heat-recovery steam generator; dampers were installed on both stacks to stop, to the extent possible, the flow of air through the HRSGs.

The skid-mounted waterside heaters are each rated 4 million Btu/hr. They circulate warm water through a few panels (harps), which then act as radiators to maintain the relative humidity below 30%. The HRSG waterside is protected by a nitrogen blanket. When steam pressure decays below 50 psig following a unit shutdown, nitrogen is introduced automatically. Another enhancement installed removes air from lube oil flowing to the torque converter to protect that component from corrosion.

Leaning stack. Stacks with dampers often are insulated to prevent heat loss through the wall of the vertical cylinder. The first speaker didn't mention stack insulation as a deterrent for offline corrosion but the second speaker showed how important periodic inspection is if you do. An operator making rounds at the 250-MW 1 × 1 LSP-Whitewater LP facility noticed rust stains on the stack and observed excessive movement of the chimney during a wind storm.

Closer inspection after removing insulation from around the ring supports of the insulated stack revealed significant corrosion at the damper level that had completely penetrated the metal in some spots. A civil survey revealed that the stack was 10 deg out of plumb, more than twice the lean of the famous Tower of Pisa.

Root cause of the damage was localized corrosion under the exterior insulation. Water collecting around the support penetrations was being trapped under the insulation, which was behaving like a sponge. Poor QA/AC during construction was another factor. Holes were in place for drain piping, but it was not installed. Get the full story by accessing "Don't ignore your stack" by Plant Manager Todd Kutz at http://www.naes.com/literature-articles.

Sinking feeling. Next, a plant manager took the podium to report on aft bearing sag—130 mils worth. The 501F engine had about 38,000 hours and 1800 starts under its belt when serious damage occurred. Exhaust-section sag was said to have started slowly, which is common; the OEM attributed that to creep. But the sudden drop in rotor position that occurred next was not typical.

All compressor diaphragms had to be replaced, along with 200 compressor blades and Rows 3 and 4 in the turbine section. There were no cracked struts, but there were cracks in strut shields. The speaker reported plant personnel remembered hearing a helicopter-like sound on startup. Vibration had not been an issue.

The dead-air-space baffle is designed to keep exhaust flow from reaching the outer shell of the exhaust section.

The OEM currently is on design revision III, which was made necessary by failures of segments designed to Rev II, a user reported. Rev III reportedly is working well; future revisions probably will involve materials upgrades. One challenge is that baffle material must be machined to fit the slot provided because mills do not offer the thickness required.

Calling Sherlock Holmes. The next speaker told of a 501FD2 forced out of service last summer after 41,000 equivalent hours and 2570 equivalent starts when a disc cavity 4 (DC 4) temperature drop of 80 deg F was confirmed by both thermocouples in that space on two consecutive starts. Temperatures in the other disc cavities were normal. A review of data captured by the historian revealed low DC 4 temperatures in the previous seven runs; however, they were not as low as those identified with the latest two runs.

DC 4 temperature was acceptable on the ensuing start. This came as a surprise and led engineers to consider that the anomaly might not be associated with the bellyband as originally thought. Plant personnel checked for instrumentation error, thermocouple damage, and bellyband failure before opening the unit, which had been opened only three months earlier to replace R2 blades. The bellybands had been replaced in 2008.

Inspection results were positive. The condition of the interstage air seal was good, with minimal mushrooming. Seal segments were properly installed and were not free to move. Bellybands were in good shape with the exception of an indication on the R4 bellyband; this was replaced as a precaution.

Another mystery then surfaced. Personnel began rolling the rotor to gain access to the bellyband and stopped when they heard a loud screech. A nut from the balance access tube cover was found trapped in the static-seal area. Personnel tried to roll the rotor again with the same result. Extensive inspections did not reveal the cause of the noise, which then disappeared. DC 4 temperature was normal following the outage. But a few weeks later, indications of a DC 4 temperature drop was recorded by one of the thermocouples. A root cause analysis provided no answer. If you have any ideas, write the editors—scott@ccj-online.com.

Where have the static seals gone? Three 501FD2 gas turbines had their R1 turbine blades upgraded during hot gas path (HGP) inspections as part of the OEM's Value Generation Program. VGP blades were characterized by short seal pins. About nine months and 220 equivalent starts following the HGP on the first unit, the unit was removed from service to change-out R2 blades.

Inspection revealed damage to R2 blades and vanes. The combustor was opened; no findings there. Then the cover over R1 blades and vanes was removed and revealed four missing static seals and heavy damage to a fir tree in the R1 disc. Recall that static seals, located inside the R1 vanes, form the seal between the HGP and DC 1 (disc cavity) by way of close clearance with the angel wings on R1 blades.

Cooling is provided from leakage along the torque tube labyrinth seals (the torque tube is that portion of the rotor between the compressor and turbine sections). Important to note is that the additional cooling required for the VGP R1 blades reduces the pressure in this area and permits the ingestion of hot gas into DC 1.

Plant personnel said there were no compelling signs of a problem prior to the outage. Review of archived data revealed two small step changes in vibration the month before the unit was removed from service, but they were not noticed by operators and were well below alarm limits. Investigators found that the reduced level of cooling was conducive to overheating of bolts holding the static seals in position. Some bolts failed, allowing seals to liberate. This was communicated to the fleet by the OEM after the investigative work was complete.

Decisions were needed on how to remediate the R1 fir-tree damage and how to increase the flow of cooling air. Options for repairing the fir tree were the following:

- Machine in-situ. This had not been done previously and was considered a high-risk solution.
- Remove rotor and machine. The normal risks regarding rotor removal and de-stack prevailed.
- De-stack rotor and replace R1 disc. Turnaround time is significant for this option.
- Exchange with refurbished rotor. A costly alternative but the one offering least schedule impact (assuming the unknowns associated with in-situ repair would have schedule impacts).

The owner chose to exchange the engine's rotor with a refurbished one. The total outage took 60 days. Static seals of the original design were installed and the old-style long seal pins used on the R1 blades.

Inspections were arranged for the remaining two engines as soon as work was completed on the first one. The second and third 501FD2s underwent their HGP overhauls five months after the first unit, so they had less in-service time with the VGP R1 blades at the time they were inspected than their sister machine had. No major problems on these units. An axially displaced static seal and two missing bolts were found on one engine; signs of overheating were in evidence on the other but all bolts were in-place.

Static seals were replaced on both units via the combustor. Replacement seal for one engine was of the original design with holey bolts (bolts with holes drilled through the center to provide a passage for cooling air) of stainless steel. The remaining machine featured a newly designed static seal together with the original holey bolts of stainless steel. The new Hastelloy static seal and honeycomb are engineered to reduce warping and loss of cooling air in DC 1.

End notes: After work on the second and third gas turbines was completed, the first unit was removed from service again, after 190 equivalent starts since the seal repair. The static seal had signs of minor warping, but no overheating. Recall that the longer R1 seal pins were installed six months earlier during the last outage. The Hastelloy static seal was installed using the new Inconel holey bolts.

Other presentations included one on exhaust cylinder crack repairs and another on spark-erosion remediation. The first plant reported that no weld repairs to the exhaust cylinder had worked, despite repeated attempts. The speaker noted that the stress on the front end of the exhaust cylinder was nearly three and a half times that at the back. Plant management decided to evaluate the service effectiveness of an overlay applied with robotic welders offered by Atlanta-based Aquilex. It took eight days (two 12-hr shifts per day) to apply the overlay, which was said to have reduced stress by 22%.

Vendor presentations

Owner/operators attending the annual meeting of the 501F Users Group who did not attend one of the five presentations offered in each of the 10 sessions that comprised the 2012 Vendorama program passed on a valuable learning experience. Vendorama is the name used to describe the lineup of vendor presentations that supplement the user exchange at this annual conference.

The steering committee expended significant effort to ensure that the 50 presentations would be technical in nature and not the sales pitch attendees would likely get in the exhibition hall. Not every presentation was worthy of an "A" grade, of course. But there were many of significant commercial value to users. Here are summaries of several presentations selected by the editors for expanded coverage.

HRSG assessment recommended for units in cycling service

Nearly all HRSG components wear at a faster rate in cyclic operation than they do in base-load service. To assure a given unit will meet the owner's expectations regarding service reliability and lifetime, Bryan F Craig, PE, of HRST Inc, Eden Prairie, Minn, recommended an engineering assessment of design details and operating practices for units already cycling as well as those expected to cycle in the future. Such a review would enable owners to correct potential weaknesses and initiate corrective action before more, or perhaps any, damage is done. It would also identify risk areas to monitor in the future.


Craig

Perhaps the most valuable take-away from Craig's presentation was a checklist of concerns that HRSG believes should be included as part of a cycling study. Criteria for inclusion in the checklist presented below, which is not complete, were the following:

- The most common concerns and ones that can cause the most significant operational and/or reliability problems.
- Issues that are not specific to one manufacturer of heat-recovery steam generators.

Within the time constraints of the session, Craig explained how to identify some of the high-profile concerns and offered guidance on how to address problems identified.

The boiler expert began his presentation with a few remarks on low-cycle fatigue. He said that many cycling-related HRSG failures are attributed to LCF, fatigue caused by repeated yielding (plastic deformation) of boiler materials. Most attendees sat straight-up when Craig said, "LCF failures often occur in fewer than 1000 stress cycles." No one needed a calculator to figure out that meant HRSGs starting daily might be forced out of service for major repairs in less than five years of operation.

Craig's checklist of most common concerns follows:

Superheater/reheater design and arrangement

- Desuperheater overspray, hunting
- HP superheater/reheater thermal stress
- HP superheater/reheater drains
- Cold-reheat condensate drains
- Proper operation of spring supports

Economizer arrangement

- Tube thermal stress at startup
- Vents and drains

Evaporator/steam drum design

- Drum nozzle cracking
- Belly pan cracking
- Drum swell

Casing/gas-side concerns

- Perforated plate and/or turning vanes with sections of varying thickness
- Damage to breech expansion joint
- Damage to pipe seals
- Casing cracks
- Damage to burner elements caused by condensate

Layup

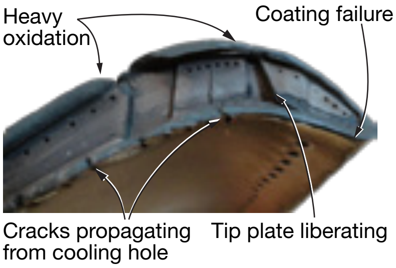
- Evaluation of practices and procedures
- Internal corrosion from oxygen ingress, FAC
- External corrosion
- Stack damper/insulation
- Freeze protection

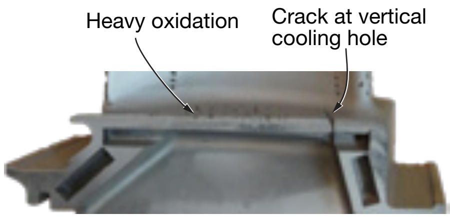
How ACT repairs R1 turbine blades

R1 turbine blade repairs are a continuing topic of discussion at meetings of the 501F Users Group. Matthew Lau, VP of operations for ACT Independent Turbo Services, Houston, presented at this year's meeting on "R1 repair fundamentals and applications."

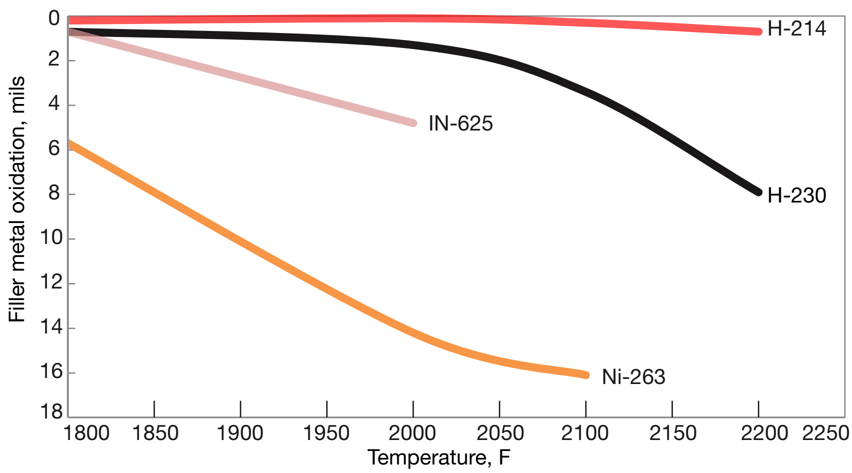

Lau

He began by reviewing some of the common failure mechanisms for R1, with a focus on blade tips and platforms (Fig 1). Lau explained that oxidation reduction/avoidance is important in both failure areas, and weld-filler alloy selection (Fig 2), improved cooling schemes, and advanced coatings are the best tools in a repair facility's arsenal to achieve this goal.

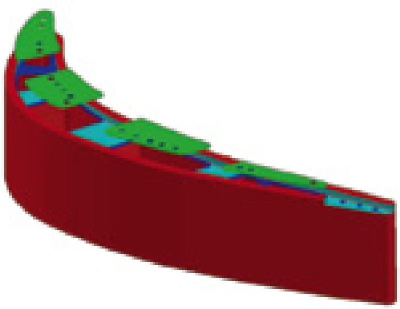




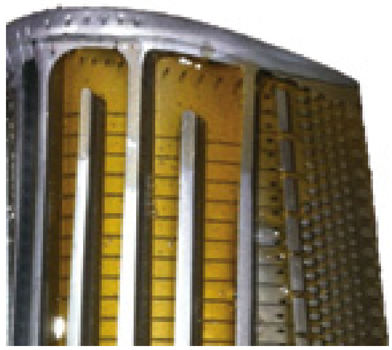
1. Failure mechanisms often identified with the OEM's original R1 turbine blades at the tip (left) and platform (right)



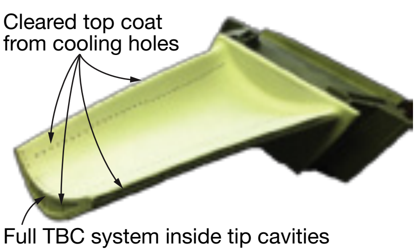
2. Weld-filler alloy selection is critical to long-term life of repaired parts. From the data available, H-214 is least susceptible to hot-gas oxidation at temperatures up to 2200F



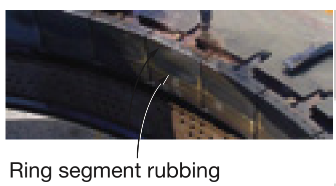
3. Tip-cap configuration and geometry are important; use of a welded-in multi-plate tip design was said to reduce the risk of liberation and premature failure

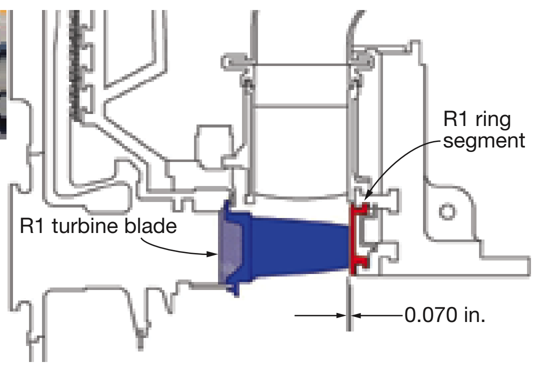


4. ACT's Matt Lau said the trick to applying internal aluminides during the repair process has been to find a cost-effective coating that does not block existing internal cooling passages



5. MCrAlY flash coat on the upper half of the shank, and wrapping of the TBC system on the platform edges, help avoid oxidation attack in critical areas





6. Tip clearances are too tight, Lau told the users, and this is conducive to rubbing of ring segments (left). He suggested opening clearances from the 0.070 in. ±0.006 in. specified by the OEM (right)

The repair expert defined the chemistry and properties of the blade base material (738LC) and repair-alloy candidates. ACT uses Alloy-214 to address platform cracking issues, Alloy-230 for tip welding, and Alloy-230 for most tip-plate replacements. He mentioned that an alternative nickel/cobalt tip-plate alloy sometimes is selected for engines in peaking service.

Lau reiterated that although properties like ultimate tensile, yield strength, toughness, and creep resistance are important, oxidation resistance is paramount for weld-filler alloy selection at the blade tip, where stresses are relatively low. Tip-cap configuration and geometry also are important and converting tips to a welded-in multi-plate design reduces the risk of blade-tip liberation (Fig 3).

On blades with severely distressed platforms, ACT uses a patent-pending process that incorporates an engineered sintered preform made of Alloy-214. Lau said that the preform's properties are engineered with high uniformity, oxidation resistance, and low porosity. The process removes the distressed area via machining until all cracks and oxidation-affected areas are eliminated. Deep cracks are "surgically" removed and welded prior to continuing the platform restoration process.

After a proprietary cleaning process, ACT restores the area with the sintered preform and Capillary Action Bonding (CAB) process in a vacuum furnace. The final step in platform restoration includes machining of the platform geometry and the addition of cooling holes.

Although the coating systems are an integral part of advanced-technology blades, Lau noted that diffused internal aluminides often are overlooked despite being critical to protecting newly deposited repair welds and cooling holes (Fig 4). The trick to applying internal aluminides during the repair process, he said, has been to find a cost-effective coating that does not block existing internal cooling passages.

Lau continued, next describing an F-class strain-tolerant coating with high-density, microstructural features for enhanced thermal-shock resistance and porosity levels conducive to low thermal conductivity. He explained that having an excellent TBC system is not enough and that application and tolerances make the difference. Lau added that coating inside the tip cavities, applying MCrAlY flash coat on the upper half of the shank, and wrapping the TBC system on the platform edges help avoid oxidation attack in critical areas (Fig 5).

Lau ended his presenation with a discussion of blade tip heights and clearances. The design clearance is too tight, he believes, and should be increased by as much as 40% (Fig 6). Lau added that a repair shop should never decrease the spec tip clearance; he also advised attendees to consider dimensional distortion and coating clearances during the restoration of R1 ring segments.

Lau's concluding comment to the users was that several of the mods discussed could be applied to new or pre-engine-run blades. If applied correctly, these applications can improve the repairability and overall life of the blades, thereby significantly reducing costly fall-outs.

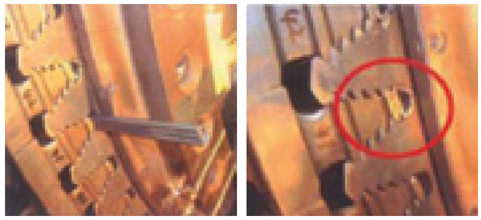
Mitsubishi promotes upgrades for 501F rotors


Cloyd

Scott Cloyd, director of gas turbine engineering for Mitsubishi Power Systems Americas, presented on the following of his company's upgrades for 501F rotors:

Belly bands (or baffle plates if you prefer) seal against air leaks between turbine rotor disks. You don't have to attend many 501F meetings to realize belly-band issues strike a nerve in many users. Cloyd suggested that users consider replacing their original belly band with Mitsubishi's two-layer baffle plate and bolted locking piece as several users already have done. He said this mod could be made any time the turbine casing is lifted. Some machining is involved, he added, because the existing slot must be enlarged. A benefit of the design was said to be easy removal when leaks occur.

Blade root springs. Disk serration wear caused by long-term operation on turning gear now can be mitigated with a patented blade root spring that is slipped between the wheel and the bottom serration of the blade (Figs 7, 8). The spring forces the blade out into the running position and eliminates turning-gear wear. It also tightens the vibration profile of the machine making vibration more repeatable from start to start. At the present time, the spring is only designed for R4. A typical row can be equipped with springs during a 48-hr outage. Access is via the exhaust duct with removal of the locking plates. A cover lift is not required.


7, 8. Root spring forces the blade out into the running position and eliminates wear attributed to operation on turning gear

Bolted air separator is designed to replace goose-neck air separators still in use on FC and FD machines. In the latter, the seal of the air separator to the R1 turbine disk is provided by the spring force of the goose neck against the air separator. The force at this point is critical to the rotor:

- Too low a force leads to fretting at the disk interface.
- Too much force reduces the preload at the spacer disk and increases wear at the curvic coupling.
- Startup and shutdown thermal transients adversely impact the preload and result in high rotor vibrations.

Cloyd said the bolted air separator decouples the seal portions of the device from the rotor core. New components required are the air separator, seal ring, dummy rings, and bolts. Modifications are required to the torque-tube seal housing and R1 turbine disk. The retrofit requires de-stacking of the rotor and makes most sense to conduct during a comprehensive rotor inspection.

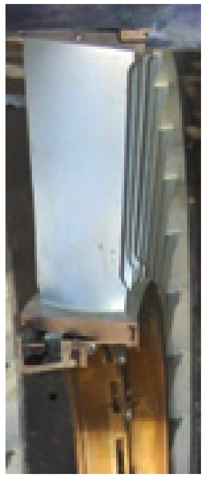
For history buffs, the bolted air separator has been used in Mitsubishi gas turbines since 1996. Siemens stayed with the original air-separator design developed by Westinghouse and Mitsubishi when the latter went to the bolted design.

Beyond the engine: PSM pursues exhaust-case solutions

Many experienced 501F owner/operators have been following the development of PSM's product line for several years and they knew many of the things Manager of Airfoils Engineering Chris Williams spoke about during his presentation. But most were hearing about the company's move into exhaust-case solutions for the first time.

Williams began with the company's compressor solutions, which were divided into the following groups:

- The S1-3 diaphragms, installed without case modification, are designed to run 96,000 hours without repairs (Fig 9). The first set installed was heavily instrumented and operated without restriction on a standard IGV schedule. The speaker said everything worked as predicted: airfoil strain below design limits, accelerometer response minimal at all IGV settings, and no measureable wear on indicators (buttons). Today, six sets of these diaphragms are in service with nearly 25,000 total accumulated hours of service. The fleet leader is north of 12,000 hours.


9. Redesigned S1-3 diaphragms are expected to serve 96,000 hours without repairs

- S4-8 501FD diaphragms also are designed for 96,000 hours without repairs. They will be available for commercial application later this year. Features: forged and machined singlet airfoils and ID/OD rings, 180-deg bolted ID seal box with split-line jumper, no welds or case modifications, ID honeycomb improves performance.
- S9-16 design improvements include ID honeycomb for better sealing, coated hook contact surfaces, and replacement of the belly band with full-penetration welds. The last is based on the company's success with 7FA S17/EGV assemblies. These diaphragms also will be available for commercial application later this year.

Combustors. Williams said PSM has studied all of the field issues and is offering a drop-in 501F combustor designed for a 24,000-hr/900-start interval. Operating experience to date extends beyond 14,000 hours/400 starts. A substantial reduction in NO_x and lower CO emissions compared to OEM hardware was promised.

R1 turbine blades. Next, the airfoil engineer reviewed the historic fleet issues with R1 turbine blades—such

10-12. Historic R1 turbine-blade issues include pressure-side platform cracking (10), failure of brazed tip plates (11), and trailing-edge root-slot cracking (12)

as suction-side platform cracking, trailing-edge root slot cracking, etc (Figs 10-12)—and showed by way of detailed graphics the design enhancements incorporated by PSM to address known field distress. These include the following:

- Dense vertically cracked coating to increase tolerance to coating spallation and cracking.
- Through-platform pressure-side cooling holes to reduce thermal strain and stress.
- Undercut leading edge and extended axial seal slot reduce platform stresses and thermal strain.
- Larger under-platform dirt pocket to prevent pin lock-up.

The company has 33 sets of R1 blades in service today; the first began operating in 2008. Duty cycles include base load, peaking, and mixed duty. Several sets have logged more than 15,000 hours/500 starts without pressure-side platform distress and with minimal suction-side distress.

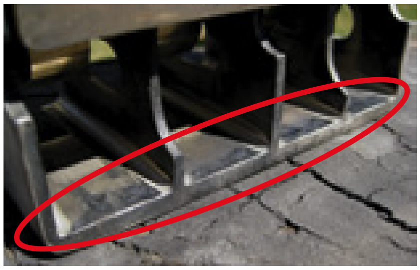
R2 turbine blades, a major topic of discussion at last year's meeting, have been in service since February 2011; 13 sets are now operational. Prediction is a three-interval lifetime.

Exhaust design improvements. Williams said PSM engineers understand the exhaust failure modes that the fleet is experiencing—such as strut over temperature and baffle-plate and teardrop issues. The company's new R4 blade is said to optimize strut-shield and teardrop gas flow. The introduction of exhaust-end components is planned for the end of 2013.

How to solve brush and brush holder problems

Cutsforth Inc's Mike Biroschak conducted a short clinic on common brush and brush holder problems and how to deal with them. He closed out his presentation with a solution for bearing wear and tear caused by ineffective shaft grounding systems.

Biroschak began by saying that the buildup of carbon deposits in brush holders is the primary cause of collector-ring fires. The buildup of small mounds of carbon inside the brush holder is one cause of brush hang-up (Fig 13). Carbon particles are produced by the repetitive impacting of the brush against the holder wall. Such buildup is difficult for maintenance personnel to see but it can be identified from marks made in the side of the brush.



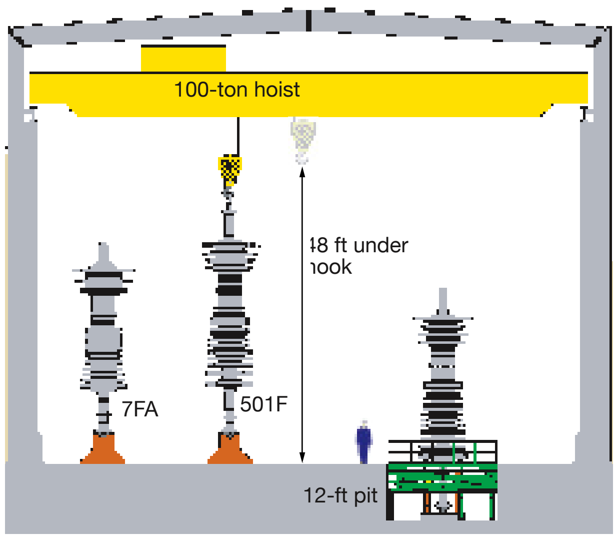
13. Buildup of small mounds of carbon inside the brush holder is one cause of brush hang-up

Brush binding is another cause of holder-related restriction. It is caused by the brush dragging against the side of the holder. Angular pressure increases the likelihood that the brush will become stuck in its holder. Where the brush box is shorter than the brush it holds, a ledge can develop in the brush and cause it to hang up.

Worn, damaged, or broken springs lose some or all of their tension and cause brush wear and out-of-round rings. Too much spring tension can increase brush wear but not mechanical wear of the ring. Biroschak pointed out that most springs are attached to the back plate of the brush holder and cannot be changed without a shutdown. That is not the case with the Cutsforth solution.

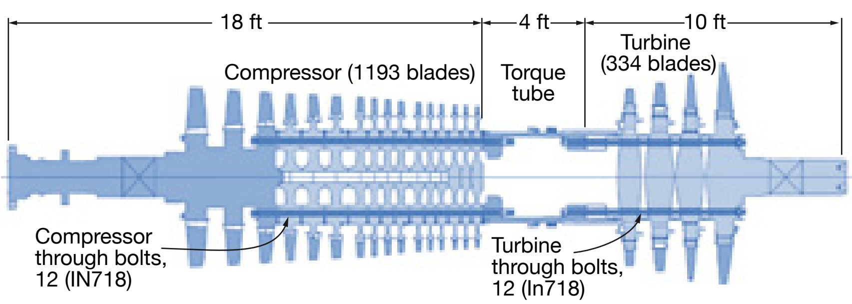
Sulzer's Romero talks rotor repair to 501F users

Sulzer Turbo Services' Engineering Advisor Fernando Romero offered an instructive look at the dismantling of a 501FD2 rotor, inspection of its component parts, appropriate rotor repair methods, and reassembly (Fig 14, 15). He said Sulzer had done work on a dozen such rotors, dismantled six, and found failed components on two



14. 501FD2 rotor has a total weight of 54 tons (right)

15. Investment in facilities and tooling to inspect, dismantle, repair rotors and rotor components is substantial (below)



of the six. To learn more about rotor disassembly, read "Recovering from a wreck," which appeared in the 4Q/2009 issue of the CCJ.

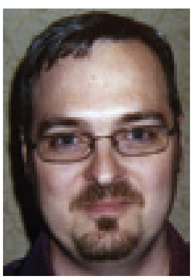
The first case history Romero discussed was a rotor that had been removed from operation because of high vibration resulting from a turbine blade failure. The aft end of the third turbine stage had high run-out and a 360-deg, 1-in.-deep crack was found at the third-stage pilot. Fracture surfaces showed evidence of heating, rubbing, and beach marks indicative of fatigue. Corrosion pits were easy to see on the OD of the rabbet fit under an optical microscope. A scanning electron microscope revealed corrosion pits at the crack initiation sites.

The rotor showed no signs of intrinsic material defects that could have contributed to this failure. However, corrosion pitting was linked to the dozens of initiation sites found at the OD of the part. An insert was designed to take the place of the pilot, which is only used for assembling the machine. The design was qualified by using finite element analysis.

Second case history. The rotor, taken out of service because of a lube-oil-system failure, did not exhibit abnormal vibration or run-outs. However, both the compressor and turbine shaft ends suffered heavy rubs. Plus, the pilot had failed and was hanging from the fourth-stage disc. Additionally, the compressor shaft end had deep rubs in the oil seal area and the probe targets were out of tolerance. Shaft surfaces were repaired by submerged arc welding, then the shaft was stress-relieved and finish-machined.

Allied Power's R1 turbine-blade repairs, mods reduce scrap rates, extend part life

Technical Director Aaron Frost of Allied Power Group (APG) explained to a packed room during the Vendorama program how advanced repair techniques and design upgrades offered by the Houston-based company can extend the run time of R1 turbine blades made by both the OEM and a third-party supplier up to 24,000 equivalent operating hours (EOH). The company's enhancements are applicable to all R1 blades in service except for the OEM's advanced-design airfoil, Frost said.



Frost

The repair expert began his presentation with an examination of the OEM's "old" R1 blade, made of equiaxed Inconel 738 and equipped with an "ineffective" cooling slot. Industry experience is that you can expect severe platform oxidation with this 14-yr-old design. Several photos were offered as proof.

Historical data from 2008, Frost continued, indicate that you can expect to lose one-third of the R1 blades in base-load units after 12,000 to 16,000 EOH. Engines not operating in base-load service can suffer nearly 100% scrap. APG's work shows that for this blade design, platform cracks occur very quickly in life for starts-based machines. Specifically, Inconel 738 can crack in only 140 starts.

Examination of braze repairs by the OEM showed them to be generally ineffective. Braze consistency is difficult to control, Frost said, and sometimes it doesn't fill the crack as it might appear. High porosity is another problem encountered.

A third-party supplier of new R1 blades has had some success by rounding platform edges to reduce cracking potential, he added. Also, the cracks are not propagating quite as long because of this design improvement. For these blades, a deep-crack platform weld repair can be effective. Crack removal and fluorescent penetrant verification are the first steps. Weld repair comes next, followed by heat treatment and full fluorescent penetrant examination. A couple of cut-ups for metallographic examination are recommended.

For an OEM set, all burned and weakened base material at the platform edge must be removed before weld repairs. Photos illustrated these points as well. Allied's welding is done with an alloy weaker than Inconel 738 but one significantly better than 625, the usual choice. That's as much information as Frost was willing to share. After the platform is fully welded, the front face is remachined to assure proper seal-pin fit, APG's platform cooling mod is installed, and another mod implemented to prevent buildup of problematic foreign material behind the seal pin.

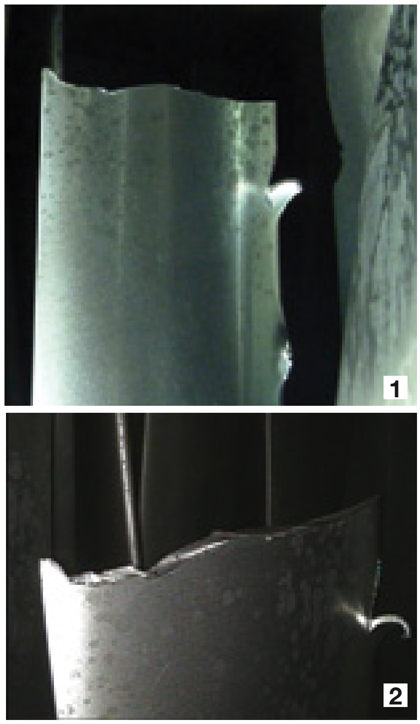
New tip-cap welding and reconstruction procedures follow. Allied uses Haynes 230 material for its tip cap. First step in the process is to remove old tip caps and cooling holes, then pre-cap weld, tack weld the new tip cap, complete the tip-cap weld, and add the squeeler tip. Finally, the cooling holes are replaced, completing the repair. Each piece then is checked by CAT scan x-ray. Final step in the rehab process is the application of dense, vertically cracked TBC. CCJ

BUSINESS PARTNERS

Latest concern for 7FA users: S1 tip liberation

Rod Shidler and Mike Hoogsteden of Advanced Turbine Support LLC (ATS), Gainesville, Fla, met with the editors during the Western Turbine Users Group meeting and passed on photos of an S1 tip liberation at the 6 o'clock position that caused extensive damage to a 7FA flared compressor (Figs 1, 2). This event occurred the first week of March and was the second such incident witnessed by the engine inspection experts at ATS.

Save! Only a couple of weeks later, Shidler emailed the photo of a cracked S1 stator vane found by one of its inspectors the first week of April (Fig 3). The plant had asked ATS, based on a published report of the accident



1, 2. S1 vane tip liberation at the 6 o'clock position caused extensive compressor damage in early March 2012

3. Crack in S1 stator vane was found in the lower half of the unit in early April 2012 described above, to check S1 vanes while it was performing the OEM-recommended inspection of S0. How many more starts did this vane have left before the tip liberated?

The OEM, to the editors' knowledge, has not issued a Technical Information Letter pertaining to S1 airfoils. The closest the manufacturer comes is with its TIL 1509-R3 which addresses R0, R1 and S0. This document recommends an annual visual inspection for R0 root cracking, R0/R1 tip discoloration, rolled metal, and/or tip loss. It provides detailed recommendations if any of those deterioration mechanisms are identified. For S0 stator vanes, inspection personnel are urged to look for trailing-edge cracks and if found immediate replacement is recommended.

Team ATS is not in complete agreement with the recommendations in TIL 1509-R3. It believes that annual visual inspections are not sufficiently comprehensive and have the potential to miss small or tight indications that could result in blade liberations and a catastrophic compressor event. Proof: The company's inspection experts have identified multiple rotor-blade cracks with visible dye penetrant that were not seen during unaided visible inspections.

In addition, ATS's state-of-the-art eddy-current inspection tools have identified S0 trailing-edge stator-vane cracks in the initiation phase that measured smaller than 0.080 in. These indications were not identified visually, even with the use of fluorescent dye. Company personnel also have found S0 leading-edge and radial-tip cracks in both flared and unflared compressors, which are not addressed in TIL 1509-R3. To those indications, you can now add the S1 experience.

ATS has recommended for several years dye-penetrant inspection of R0/R1 blades and dye-pen or eddy-current inspections of S0 vanes annually or every 100 fired starts. Subsequent inspections based on the results of the initial investigations would run parallel to the OEM's recommendations. More recently it has recommended eddy-current inspections of S1 because of the earlier liberation.

The early March liberation occurred in a base-load unit that had logged more than 55,000 hours of operation. The plant is not located in the so-called "Ring of Fire" near the coastline where some engine parts generally are believed more susceptible to damage. ATS visually inspected the unit only by borescope in November 2011, at the customer's request. Vibration signature changed in December but the unit did not trip and continued in service until the spring inspection when the damage was discovered.

Shidler said ATS can eddy-current check all the vanes in S0 and S1 during a top-on inspection. The company's technicians can also get to some vanes in rows S2 and S3. He added that inspecting S1 after an eddy-current inspection of S0 only adds about 25% to the invoice.

DRS celebrates 10 years of vane pinning

Rodger Anderson, manager of gas turbine technology for DRS-Power Technology Inc, Schenectady, NY, called to say that the pin locking system he developed to prevent shims used in the vane rows of GE frames from protruding and liberating into the flow stream quietly passed its 10th anniversary (Fig 4).

More than 120 turbines worldwide are running with over 80,000 pinned vanes. Fleet hours total more than 3 million; multiple fleet leaders have passed 48,000 hours. Reliability is 100%—meaning there have been no vane failures or shim liberations since the first vanes were pinned.

4. Pin locking system keeps shims from protruding and liberating into the air flow stream

The pin system also locks the vanes into a robust ring segment which stops fretting wear caused by loose vanes in the casing grooves. Pinning technology restores the vanes and shims to their "as new" positions without installing patch rings. This improves gas turbine performance by as much as 0.3%, Anderson said, which translates into an annual fuel saving of up to $150,000 for a base-load 7FA.

The compressor expert said the following GE engines are benefitting from pinning: Frame 5, 6B, 7EA, 9E, 6FA, 7FA, and 9FA. Pinned vanes are operating in Southeast Asia, Middle East, UK, Australia, and throughout the Americas.

SPS, ORAP® celebrate 25 years of service to the industry in 2012

Since 1987, Strategic Power Systems Inc, Charlotte, has processed and added to its ORAP database plant operational, failure, and maintenance data representing more than 22,000 unit years and over 280,000 forced, scheduled, and unscheduled outages. Today, information from over 2000 gas and steam turbines are reported on a monthly basis for review and validation prior to being entered into ORAP. It is these data that allow SPS to provide RAM benchmarks for use in the energy market for both heavy duty and aeroderivative plants across the various OEMs, technologies, applications, and duty cycles.

Data come to SPS from a variety of plant sources, including onsite operators and maintenance personnel, as well as from central operations staff. In some cases, SPS obtains operating data directly from the unit control or onsite historian; however, outage detail must always come from site or central staff.

Eight Bells

Kevin Million, 49

Kevin Michael Baker Million, a senior plant operator at the Klamath Cogeneration Facility, Klamath Falls, Ore, died early in January 2012. Previously he worked for Fresno Cogeneration, following eight years in the US Navy where Million served as a gas turbine mechanic and nuclear field operator.

Team Klamath remembers him as always being concerned about his immediate family as well as his work family. One of several duties at the Oregon plant was onsite chemist.

Million is survived by Jan, his wife of 28 years, and children Makayla and Brandon.

Andrew Lazarus, 87

Andrew Lazarus, founder of New York City-based public relations agency, A J Lazarus Associates, died early in January 2012 in Portland, Ore. "Back in the day" he was well known in the power generation industry, with such blue-ribbon clients as Curtiss/Wright, ABB Power Generation/Alstom, Rolls-Royce, ASME Gas Turbine Div, and Black & Veatch.

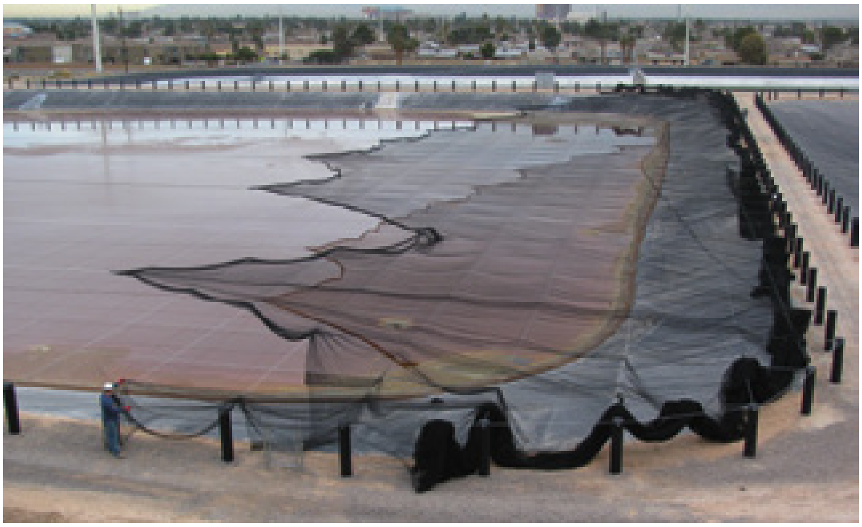
Andy Laz, as he was called by industry friends, started his agency in 1968 and retired in 2004, succeeded as president by his daughter, Chris Lazarus. He began his industrial PR work at Dow Chemical, then Gulton Industries, before going on to head PR departments for two New York advertising agencies.

Gas turbine consultant Sep van der Linden (article, p 120) had this to say, "Who could forget his class, his enthusiasm? He had the nose of a hound, one capable of sniffing out any news item that could be used to positively place a client in good light. Give Andy a few thoughts and he could produce a world-class news release. We met when I was at Curtiss/Wright and he followed me to ABB, characteristic bow

tie intact and with that big smile of his."

This editor remembers Andy Laz as the person who introduced him to the emerging land-based gas turbine industry, and its leaders (van der Linden among them), in the early 1970s. He was a true professional in a difficult business, fine writer, persuasive, well respected, and all-around "good guy."

Lazarus, a small-town person with a big-city degree (MA in literature from Columbia Univ), served in the Army Air Force in the Pacific during WWII and launched his civilian career as a correspondent for the NY Herald Tribune in



5. Netting is installed over evap ponds at NV Energy's Clark Station to protect migrating birds

Europe. He had a lifelong passion for the people and culture of Europe, as well as a never-ending curiosity about nearly everything.

Plant news

Edward W Clark Generating Station, NV Energy, recently completed work to protect migrating birds from coming into contact with high-salt/solids water in two of the plant's evaporation ponds. The station is in-line with certain bird-migration pathways and the company's Environmental Services and Power Generation teams worked closely with the US Fish & Wildlife Service and Nevada Dept of Wildlife to protect the fowl.

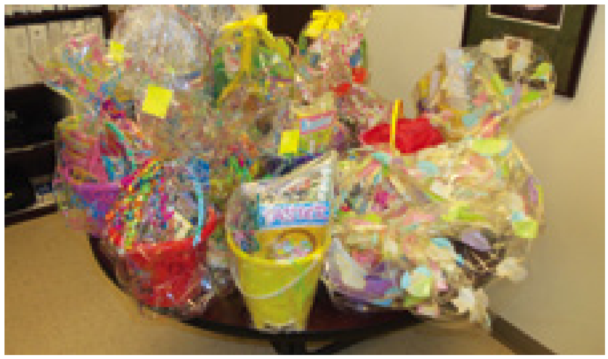
About 7 acres of netting now covers the two ponds (Fig 5); reflective flags used previously were ineffective. Four other ponds are available for the birds to use for resting and watering. More than 300 support poles and high-tension cable were required to support the netting.

North Pole GT Plant, Golden Valley Electric Assn, was honored by HRSG manufacturer, IST, as the recipient of its 2011 Plant of the Year Award during Power-Gen International last December.

Rio Nogales Power Plant, an 800-MW combined cycle is purchased by CPS Energy from Tenaska Capital Management LLC to facilitate the utility's transition to clean energy. Rio Nogales will replace the energy output of the J T Deely coal-fired plant planned for service in 2018.

NV Energy, like many other utilities, is trying to improve the safety consciousness of its employees. Its "Safety by Choice" banners might be an idea for others.

Tenaska Virginia Generating Station's employees never forget those in need during the holidays. Gift-giving at Christmas, Thanksgiving, and Easter is a top priority.



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