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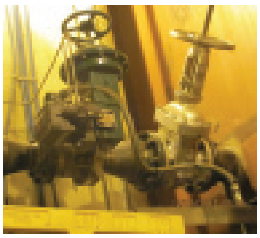
2011 Best Practices Awards



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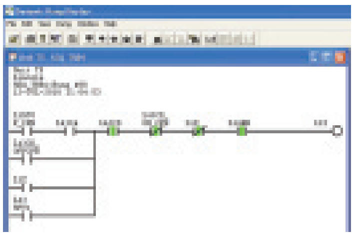
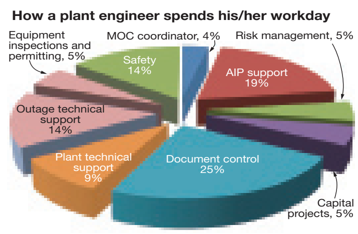


Environmental Stewardship
Lincoln Generating Facility



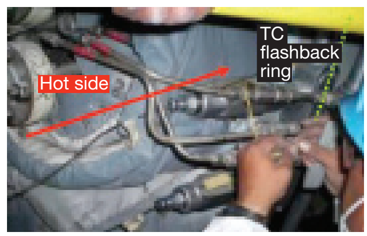
Management
Arrow Canyon Complex

Safety Equipment & Systems
Klamath Cogeneration Plant

Safety Procedures & Administration
New Covert Generating Facility

O&M, Balance of Plant
Wolf Hollow I

O&M, Business
Tenaska Virginia Generating Station



O&M, Major Equipment
CCC Saltillo

User Group Events

Special Section: HRSG User's Group 19th Annual Meeting, San Diego. Turn to page 109 to access the workshop and conference programs, locate exhibitors at the exposition, etc

CTOTF is the only gas-turbine user group meeting in the East this year. Good reasons to attend the April 10-14 event in Palm Beach Gardens: Presentation of the 2011 Best Practices Awards; roundtables on Alstom, GE, Mitsubishi, Pratt & Whitney, and Siemens engines; special sessions on HV electrical equipment, generators, regulatory and compliance issues, etc

Feature Articles

INDEPENDENT VOICE OF THE GAS-TURBINE-BASED GENERATION SECTOR

SPECIAL EDITION

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Meeting highlights

Tuesday morning

Gas-side corrosion protection of HRSGs during layup

Cliff Cracauer, *Cortec Corp*

Discussion sessions:

- Heat-transfer components
- Water treatment

Tuesday afternoon

Management of P91 pipe in existing plants

Chris Bates, *New Harquahala Generating Co*

Discussion session:

- Piping systems

Wednesday morning

Stop leaking money through your valves

Michael Flaherty, *ValvTechnologies Inc*

Discussion sessions:

- Controls, structural components
- Valves, supplementary firing

Wednesday afternoon

Improving the reliability and service life of HRSG expansion joints

Jake Sisson, Dekomte

Discussion session:

- Environmental systems, balance of plant

Grand Prize drawing at 4 pm. Users only. Must be present to win

HRSG User's Group 2011 Conference & Expo

Be sure to visit these companies on the expo floor

	Booth	Ad page
BASF Catalysts LLC	110	115
Bremco Inc	203	117
CMI Energy	402	108
Cormetech Inc	410	75
Donaldson Company Inc	407	74
EmeraChem LLC	503	119
Emerson Process Management	315	17
Express Integrated Technologies LLC	312	110, 111
General Physics Corp	403	7
Hamworthy Peabody Combustion Inc	413	124
HRST Inc	114	69
Innovative Steam Technologies	306	31
ISOPur Fluid Technologies Inc	409	95
JASC-Jansen's Aircraft Systems Controls Inc	102	11
KE-Bergmann USA Inc	514	93
Ludeca Inc	515	38
National Electric Coil	209	38
NEM USA Corp	300	113
Nooter/Eriksen Inc	415	121
Parker Hannifin Corp	202	118
Precision Iceblast Corp	405	120
Proton Energy Systems	100	105
Titan Contracting & Leasing Inc	115	125
Vogt Power International Inc	215	13

2011 Best Practices Awards Page 19

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Most user-group meetings in the gas-turbine-based generation sector of the electric power industry are held in the spring and in warm locations. The 501F and 501G Users Groups, which support engines originally designed by Westinghouse Electric Corp (now Siemens Energy Inc), have shared a common venue for the last several years and traditionally are first on the calendar.

Their 2011 conferences and joint vendor fair hosted more than 160 users in San Diego in mid February. Information started flowing at breakfast each day and knowledge transfer was non-stop through the organized evening event. Hot topic for the 501F meeting was R2 turbine blade cracking. Siemens addressed the issue, the users discussed it behind closed doors, and the steering committee invited several third-party firms to present their thoughts and solutions.

If you were unable to attend the meeting, access http://combinedcyclejournal.wordpress.com for a first-hand report by the editors. It is a compilation of four postings on **CCJ ONsite,** our new Internet-based publishing service. We'll deliver daily reports from several more user-group events this spring—including Western Turbine and CTOTF. To be sure you receive them, we must have your latest contact information—e-mail address is critical. Complete the simple registration form at www.ccj-online.com/subscribeonline.com (takes less than two minutes) and we'll update your records.

This issue features two special editorial sections linked to upcoming user-group meetings. The HRSG User's Group meets April 4 to 6 in San Diego. It is likely the largest gathering in the world of major owner/operators affiliated with the combined-cycle/cogeneration sector of the industry, drawing about 350 participants annually.

The organization has grown, since its inception in 1993, from a handful of powerplant managers to a globally recognized professional association of more than 1500 members in 50 plus countries. Our coverage includes the complete technical program, as well as exhibit hall map and listing of exhibitors to facilitate navigation of the event.

The CTOTF Spring Turbine Forum begins April 10 at the PGA National Resort in West Palm Beach, Fla. Featured event on Monday, April 11, is a special luncheon honoring the recipients of the **CCJ's** 2011 Best Practices Awards (coverage begins on p 19). CTOTF, chaired by Bob Kirn of TVA, has been supporting owner/operators of all models of gas turbines and related equipment for 36 years.

Remaining spring meetings. Don't pass up an opportunity to attend one or move of the following meetings remaining on the spring calendar. It's a sure bet you'll bring back to your plant ideas that when implemented will pay at least 10-fold return on travel expenses.

- May 9-13, 7F Users Group, Conference & Vendor Fair, Westin Galleria Houston. Contact: Sheila Vashi, meeting and exhibition coordinator, sheila@vision-makers.com.
- June 6-9, Frame 6 Users Group, Annual Conference & Vendor Fair, Scottsdale, Ariz, Doubletree Paradise Valley. Details at www.Frame6UsersGroup.org. Contact: Wickey Elmo, conference coordinator, wickelmo@carolina.rr.com.
- June 7-9, D5/D5A Users, Annual Conference & Vendor Fair, Banff, Alta, Canada, Fairmont Banff Springs. Details at www.501d5-d5ausers.org. Contact: Gabe Fleck, chairman, gfleck@aeci.org.

Gas, wind dominate announced US capacity additions

With the emergence of 'game-changing' shale gas, inframarginal rent in both the gas and power industries has changed dramatically. This phenomenon has had a significant impact on plans for new generating capacity

By Adam Picketts, Energy Ventures Analysis Inc

NV Energy's Harry Allen Generating Station, located a few miles north of the Las Vegas strip, is scheduled to begin operation in spring 2011. The 2 × 1 7FA-powered combined cycle sets the standard for environmental compliance in the West

Relatively low gas prices, combined with a heightened shale-gas production outlook, will continue to reduce inframarginal rent for owners of coal-fired assets (Sidebar 1). As inframarginal rent declines, coal retirements will accelerate because existing plants cannot compete with gas—especially if pressured to retrofit flue-gas desulfurization and selective catalytic reduction systems to reduce emissions of SO_2 and NO_x.

FGD and SCR retrofits cost roughly $900/kW for a 400-MW coal-fired unit versus $850-900/kW to construct a new combined-cycle plant. The latter estimate excludes the cost of financing and assumes non-union construction in a moderate climate. More specifically, the total cost for one western 2 × 1 F-class combined cycle with air-cooled condensers and scheduled for spring startup is $1400/kW in round numbers.

Coal retirements totaling 16 GW through 2016 have been announced. EVA (Sidebar 2) projects that about 36 GW are at risk and will likely retire. Pending EPA regulations—such as the unit-specific emission-rate limitations associated with the Air Toxics Rule—are another driver of coal retirements. Although remote, the possibility of carbon legislation after 2017 also will keep coal capacity on a downward trajectory.

Expect coal-to-gas fuel switching to grow and reduce the generation share of coal as well. Low gas prices and global growth in coal demand, combined with a weak US dollar, make it uneconomical for old, ineffi-

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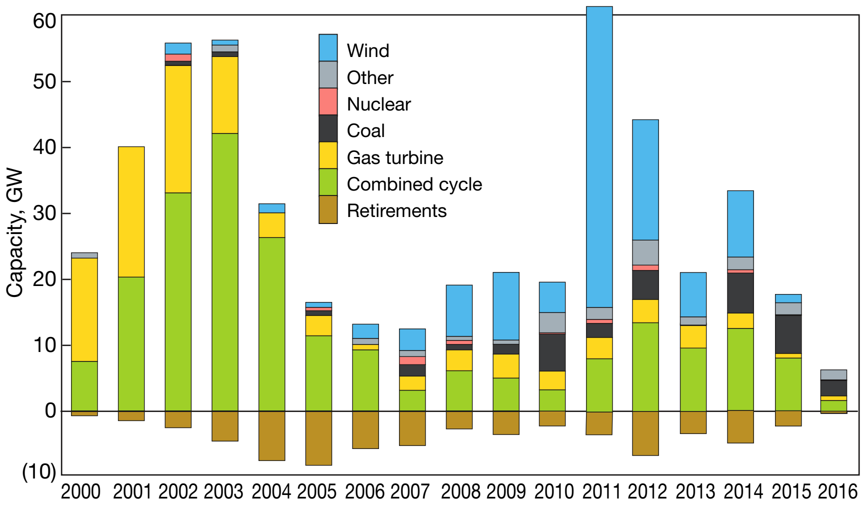
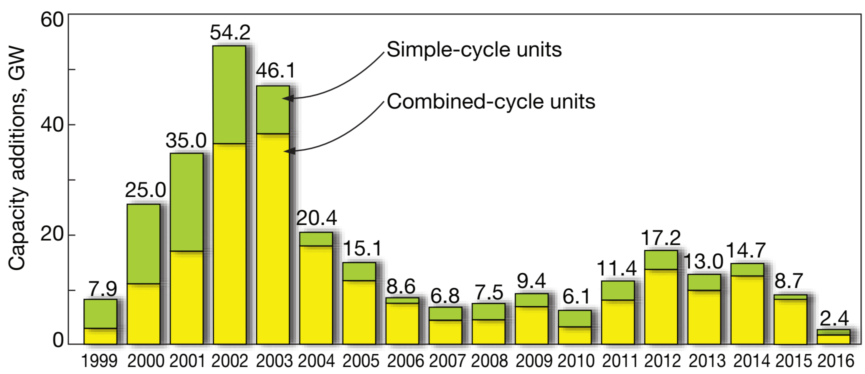
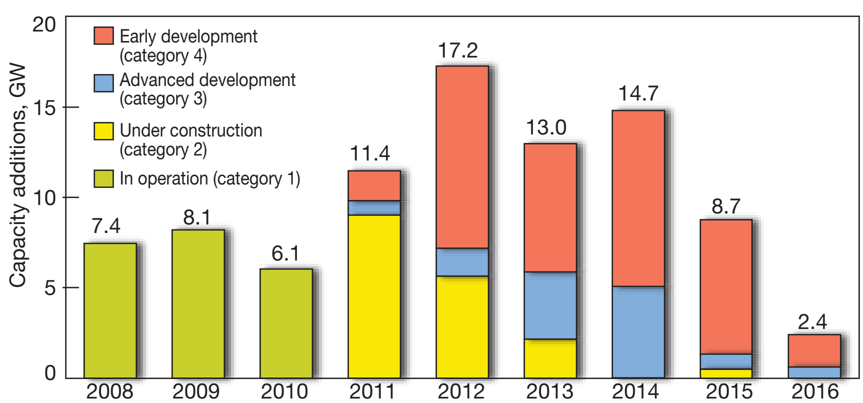


1. Capacity additions announced for calendar years 2011-2016 total 186,154 MW. Natural gas announcements are 36% of the new capacity; wind, 45%; coal, 11%; nuclear, 1%; all other, 7%. Note that the wind market is defined by renewable portfolio standards and that many announced projects have slim chances of gaining power purchase agreements and financing; also, wind is represented by installed nameplate capacity while all others are summer capability



2. Bar graph of GT-based additions suggests that a mini-boom is underway. New units are required to replace coal-fired retirements, canceled coal plants, and to balance growing intermittent wind generation. For the period evaluated, current announcements suggest that 80% of the new 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



3. Gas-turbine capacity by stage of development profiles 68 GW of announced capacity for the calendar years 2011 through 2016. Stagnant electricity demand will likely delay some projects and possibly force the cancellation of a few. Gas turbines are installed quickly and 56% of the capacity is in the early development stage, making it relatively easy to tweak startup dates. Approximately 18% of the capacity is in an advanced stage of development, and another 25% is under construction

cient coal units to dispatch ahead of gas-fired combined cycles.

Coal-to-gas fuel switching is largely an Eastern phenomenon impacting old, unscrubbed units burning high-cost Appalachian coal. Assuming natural gas becomes the base-load fuel in the East, EVA projects the maximum amount of coal generation lost to gas could be equivalent to roughly 3 billion ft^3/day (bcfd). This equates to a loss of 85 million tons of coal per year. EVA forecasts around 2 bcfd of gas generation will offset coal in 2011. This fuel switching equates to a loss of 52 million tons of coal.

Announced new coal capacity through 2016 is 16.6 GW. EVA estimates that only the few coal plants currently under construction or fully permitted (8.1 GW) will reach commercialization. These coal additions will offset only 23% of projected retired coal capacity during this period.

Wind. There are currently 83 GW of announced wind capacity additions through 2016, driven by renewable portfolio standards in 30 states and DC. However, EVA projects only about 18 GW of new wind capacity will be installed through 2016. Uncertainty over future wind production tax credits, transmission constraints, financing, and power purchase agreements will severely limit installed wind capacity.

Tax-credit uncertainty was evident in 2010 and it led to the six-month period of lowest installed wind capacity since 2007. With the tax credit extension lasting only through 2012, developers will again face financing difficulties in 2013. EVA forecasts that wind will generate 4% of US retail electric sales by 2016.

Expect additional development of GT-based projects to fill losses in coal and to offset the difference between rated and credited wind-turbine capacity. Cycling capacity will be vital in balancing wind intermittency to better correlate generation with load. Announced GT technology additions through 2016 are 67.5 GW, 80% of that combined cycle.

US retail electric sales grew by about 4.3% last year, largely driven by climate as heating degree days were 114% of the 30-year trailing normal. EVA expects demand to decline by 0.98% in 2011 and remain relatively stagnant with yearly growth of roughly 0.85% to 1.2% through 2016, absent any unusual weather events.

Across all fuels and technologies, capacity announcements for calendar years 2011-2016 total 186 GW (Fig 1). GT-based simple-cycle, cogeneration, and combined-cycle

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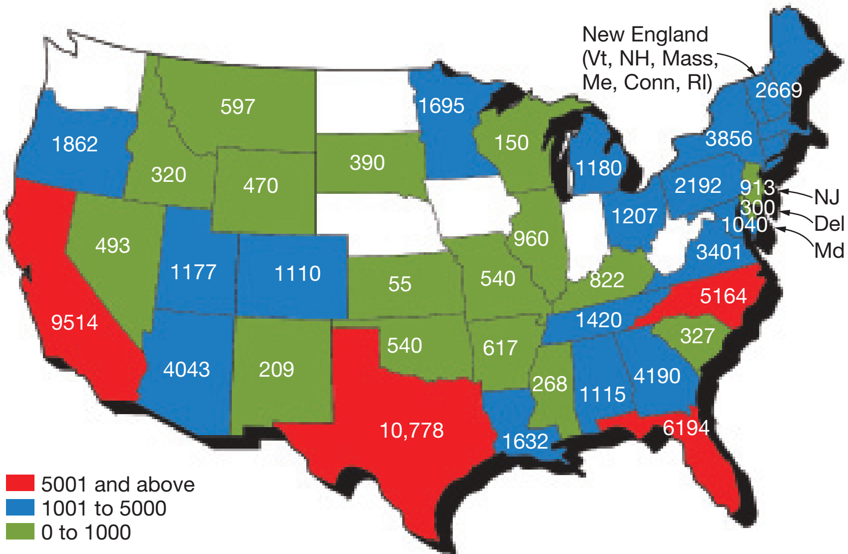


4. Looking at GT-based capacity additions in the Lower 48 for calendar years 2010 through 2016, states with the most announced new capacity are Texas (10,778 MW), California (9514), and Florida (6194)

plants account for 36% of this total. Although announced nameplate wind capacity is 83 GW, wind power producers are not credited with providing firm capacity. EVA estimates that roughly 8 GW of announced wind would be credited capacity.

GT technologies will be required to help fill the void between rated and credited wind capacity. In the nuclear arena, aside from 1961 MW of expected uprate applications, new nuclear capacity is unlikely before 2017.

Fig 2 presents the recent history and a look ahead for GT-based capacity. The illustration shows the spectacular growth of this industry sector in the 1999-2005 period, when more than 200 GW was installed.

A federal renewable portfolio standard for electricity will keep GT capacity on the near-term radar to provide a more reliable backup to wind-powered generation and to quickly fill sudden demand gaps as the economy rebounds.

EVA's tracking of power project announcements indicates that 56% of the GT-based capacity expected in service by the 2016 is in the early development stage (Fig 3). These plants are the most vulnerable to changes in developers' plans. Another 18% of capacity is in advanced development and an additional 25% is under construction.

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 3). CCJ

1. Inframarginal rent

So-called "inframarginal rent" is the profit that a power producer captures between its marginal cost of production and that of the generator with the highest marginal cost, which sets the market price.

Example: High gas prices push combined cycles back to the margin, meaning the power producer delivers kilowatt-hours to the grid at essentially its cost of generation (no profit). Meanwhile, base-load coal-fired plants operating on lower-cost primary energy receive for their electricity a price equal to the marginal generator's cost.

By contrast, low gas prices reduce the inframarginal rents for coal-plant owners because coal is no longer as competitive as it was when the price of gas was high. In some cases, the cost of gas on a heating-value basis drops to where it becomes the most economic base-load fuel, pushing coal to the margin and minimal profitability.

2. 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.

3. 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.

‘And you thought the housing market was lousy’

Those were the first words Mark Axford spoke at his annual January sit-down with the editors to review the US and global markets for gas and steam turbines. The founder of Houston-based Axford Turbine Consultants, respected for his solid industry data, provided a market analysis for 2010 based on actual orders placed during the first nine months of the year.

“The recession that has been felt throughout the US has been especially hard on the power generation business,” Axford said. US orders for both gas and steam turbines fell again during 2010 (Figs 1, 2).

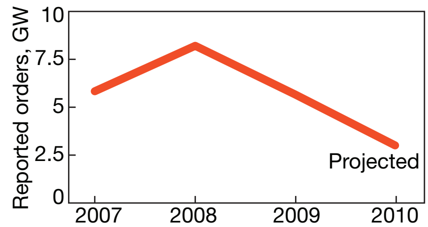
The fundamental problem, he added, was that industrial demand for electricity continued to stagnate in 2010 because the recession forced factories to operate at relatively low capacity factors.

While cumulative kilowatt-hour consumption in the US was up 4.2% in 2010 versus 2009, most of that gain was attributable to a very hot summer (Fig 3). Air conditioning load was significantly higher than average. Even with the significant bump in kilowatt-hour sales last year, consumption was still below the figure for 2007.

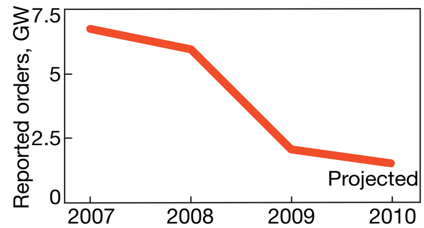
Assuming “normal” summer weather for 2011, DOE predicts electricity consumption will be lower in 2011 than it was in 2010. This would mean three down years in the last four for the first time in the nation’s history.

Globally, Axford said, 2010 orders for gas turbines essentially were flat, while those for steam turbines were off by about 25%. Geographically, he continued, gas turbine orders were spread relatively uniformly around the world. But steam turbine orders were concentrated in Asia because both India and China are adding considerable coal-fired capacity.

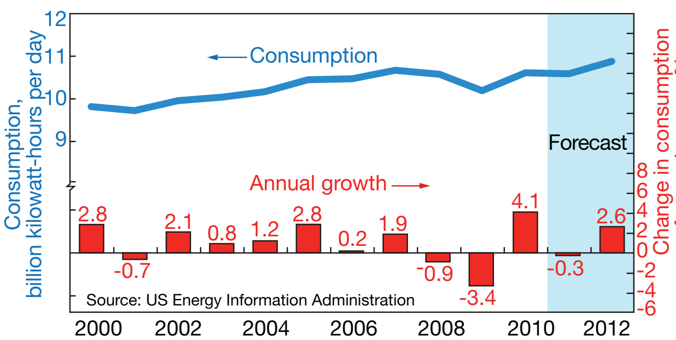
Axford believes that “until we see a steady increase in the demand for electricity of 1% to 2% annually, and a return to ordering of new generating capacity based on the lowest total cost of delivered electricity [no subsidies], construction of simple- and combined-cycle power stations will remain subdued.” CCJ



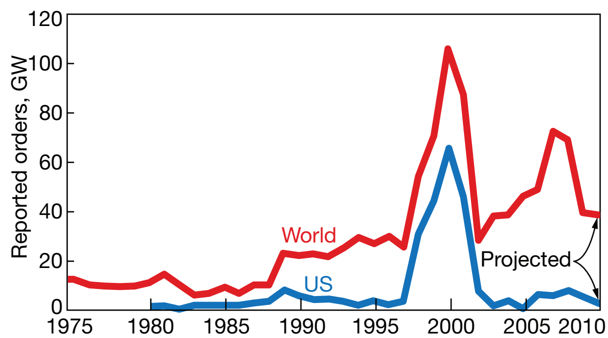
1. US gas turbine orders for units larger than 10 MW dipped again in 2010. Data are for engines larger than 10 MW



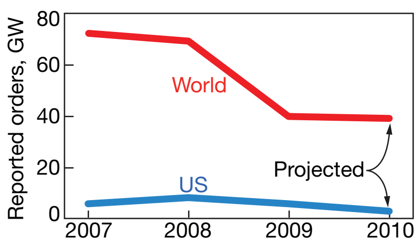
2. US steam turbine reported orders in 2010 were few and far between



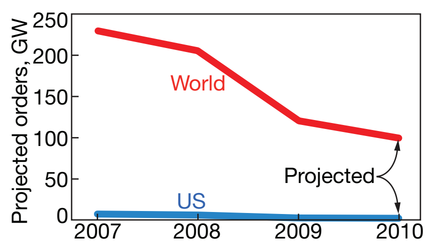
3. Total electricity consumption in the US in 2010 was less than that recorded in 2007



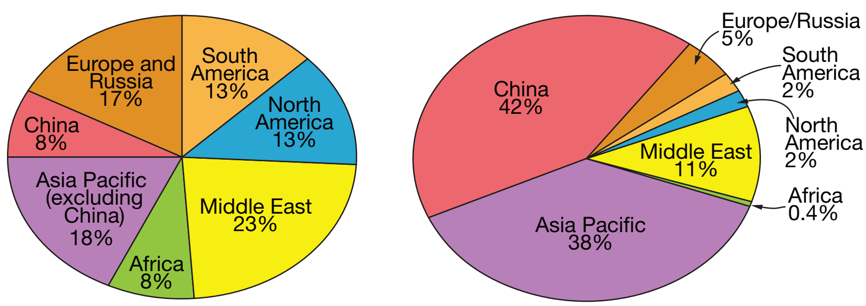
4. Gas turbine orders worldwide and US for the last 35 years. Data from 1990 to date are for units larger than 10 MW



5. Detailed look at gas turbine orders worldwide and US for the last four years



6. Steam turbine orders worldwide are off sharply because of the recession



7, 8. Geographical distribution of 2010 gas turbine orders (left; 28,997 MW through Sept 30) reveals a relatively even spread in sales worldwide. Steam turbine orders (right; 99,250 MW projected for the year based on 3Q/2010 data) are dominated by sales activity in China and Asia Pacific (primarily India)

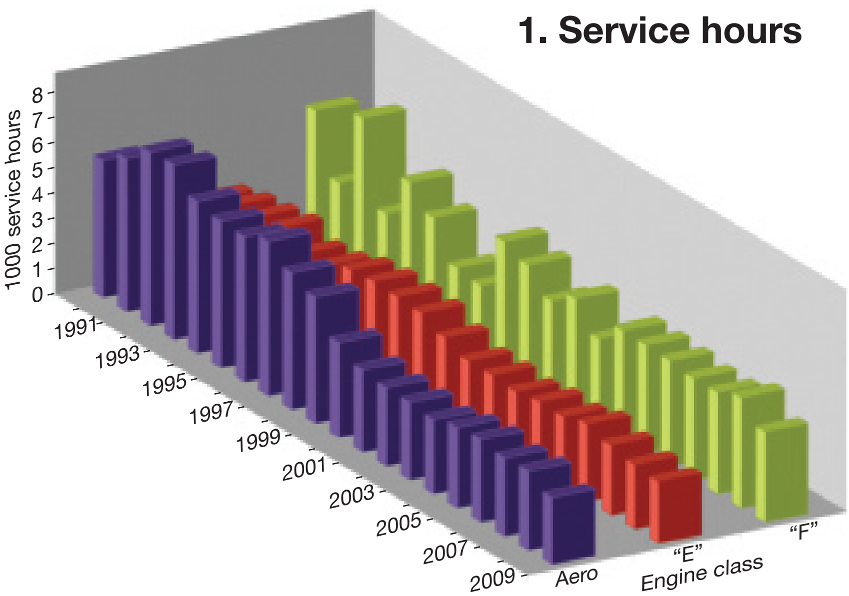
Changing duty cycles and gas turbine reliability—a look back

By Salvatore A DellaVilla Jr, Strategic Power Systems Inc

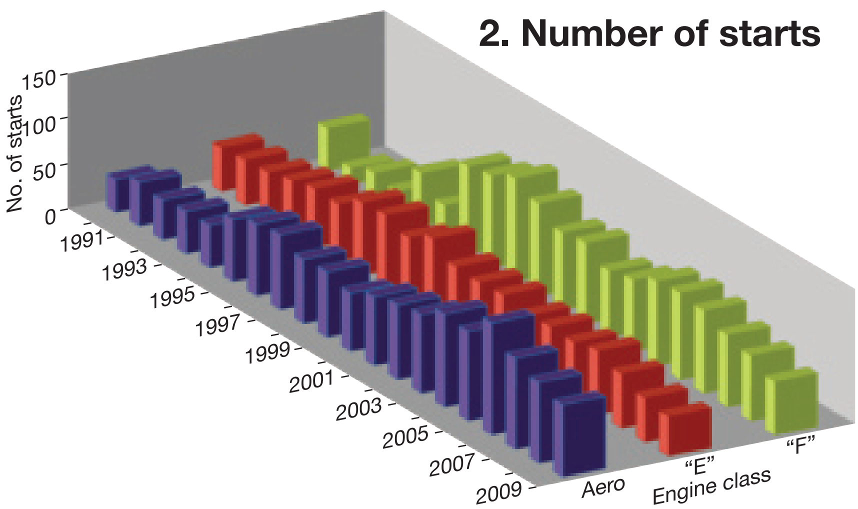
Characteristics of ORAP data sample for 1991-2010

	Aeros	"E" class	"F" class
Average number of units reported	270	230	105
Maximum number of units reported	552	290	336
Percent of units in combined cycle	72	59	87
Percent of units burning only natural gas	95	91	99

1. Service hours



2. Number of starts



"In June of 1892, a jubilant Charles Scott, the young Westinghouse engineer who had assisted Tesla when he'd first come to Pittsburgh, announced this first commercial use of the whole Tesla system, including the long problematic induction motor, in the *Electrical Engineer*. 'The aggregate time lost. . .was, by actual count, less than 48 hours during three-fourths of a year. . . .'"

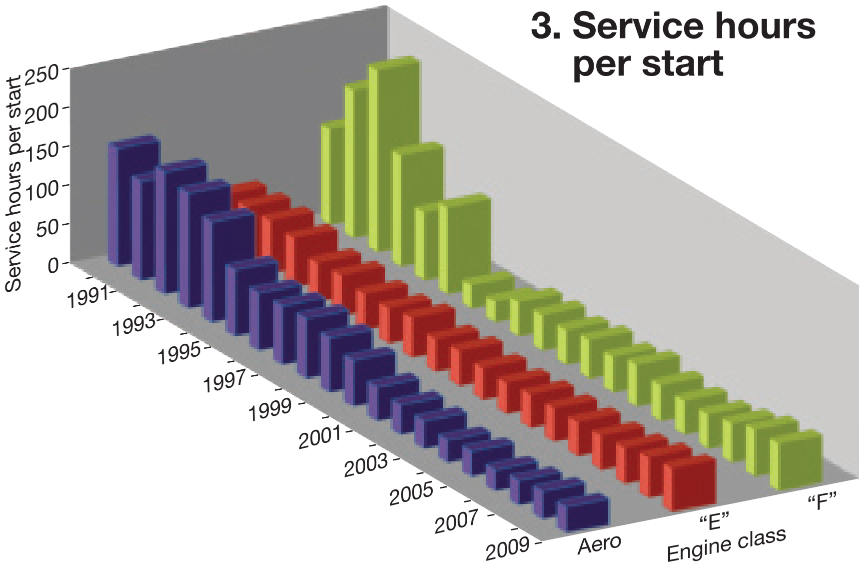
From Jill Jonnes' *Empires of Light: Edison, Tesla, Westinghouse, and the Race to Electrify the World*

Forty-eight outage hours over three-quarters of a year translates to a reliability factor of 99.3%. Thus, from the very start of the electric power industry, the reliability of each product developed—such as the first ac induction motor—was recognized as a key performance indicator required for commercial acceptance and economic viability.

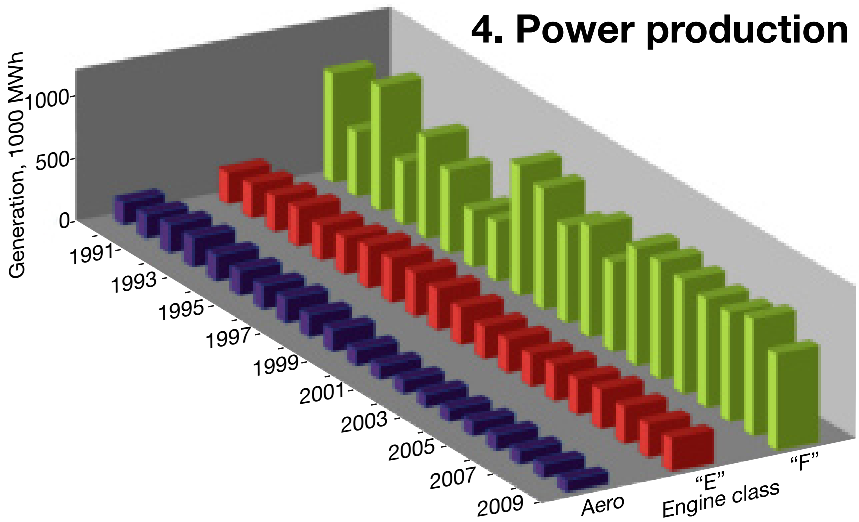
The industry has grown and the technologies it relies on have advanced, but there continues to be a need to understand how powerplant equipment is performing relative to market expectations for high reliability. Changing patterns in demand have resulted in challenging duty cycles that require operating flexibility and this will impact the reliability and capability of plants powered by gas turbines.

For more than 20 years, ORAP® data obtained from numerous operating powerplants worldwide have provided the opportunity to assess and understand trends in equipment duty and performance. The following analysis reviews ORAP data compiled for aero, "E," and "F" class engines in electric generation service

3. Service hours per start



4. Power production



to identify operational differences based on equipment size/output and performance. Two 10-year periods are compared: 1991-2000 and 2001-2010. The data pool is described in the table.

Every performance assessment should begin with snapshot of how the equipment or generating facility was operated during the period under review. Service hours, or the amount of time power was supplied to the grid—that is, the elapsed time from breaker close to breaker open—is a key metric (Fig 1). Service hours also can be characterized by service factor, or the percentage of time the unit is generating power.

In addition, the number of successful starts (Fig 2), the service hours per start (Fig 3), and the power generated (Fig 4) are important considerations necessary for understanding equipment duty cycle or mission profile. Data presented in the illustrations reflect the operation of a typical (or average) unit in the specific technology class (aero, "E," "F").

The following assessment was developed using this information.

For aeros during the period 1991-2000 there was a continual year-over-year decrease in service factor, driven by a decrease in service hours. Example: In 1992, the aeros operated just over 6000 hours (85% service factor), with 126 hours per start (48 annual starts); production was 190,900 MWh.

By 2000, annual service hours would gradually, but continually, decrease to just over 4990 hours (70% service factor), and the hours per start would decrease by more than 40% to 70. However, the annual number of starts increased by 50% to 72, while power production dropped by about 12%. This was a clear shift in duty from a typical base-load paradigm to a cycling mission profile.

For the 2001-2010 period, with year 2001 excluded, service hours were more consistent on a year-over-year basis. The service factor was between 40% and 47%, with units operating between 3100 and 3300 hr/yr. Service hours per start declined (to between 25 and 40) as did annual service hours.

The number of annual starts remained high—from 65 up to 122—which is consistent with cycling duty. However, generation declined by more than 40% compared to the previous 10-yr period (1991-2000). Once again, this reflects a clear shift in operating duty.

From a reliability perspective, it is important to note that the number of trips from load have decreased significantly year over year—from a high mark of 10-15 annual trips during the 1991-2000 period to from four to nine for 2001-2010. The time to respond, or to repair also improved significantly.

"E" class units had a very consistent mission profile year over year for 1991-2000, as evidenced by the following:

- Annual service hours of 3100 to 3600 and a consistent service factor of about 49%.
- An increasing number of annual starts (from 50 to 86), and a decreasing number of hours per start (from 65 to 41).
- Increased generation—from 245,500 to just over 346,000 MWh on an annual basis.
- Two to three annual trips from load, with a time-to-repair of 30 to 100 hours—a consistently high level of reliability.

From 2001 through 2010, service factor declined and fluctuated slightly, but over time could be seen as relatively consistent in the range of 34% to 41%. Annual service hours fluctuated between 2400 and 3100, while service hours per start increased from 44 to 56.

Power production was fairly consistent throughout the period, ranging from 252,700 to 308,300 MWh annually. The reliability of "E" class machines remained high with only two trips from load on an annual basis and with the time-to-repair dropping to 30 to 60 outage hours.

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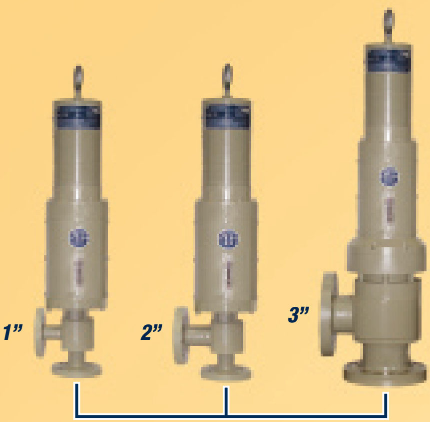
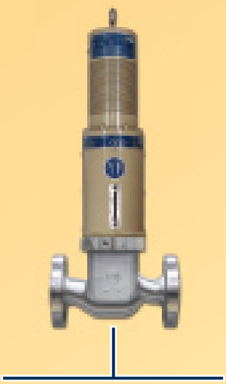


3010E500 Series
Integrated Natural Gas Fuel Control Valve Assemblies



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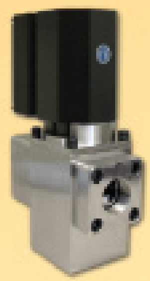
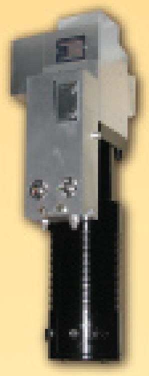
1.5” and 2” Line sizes available



The Y&F 8641 Series
Integrated Natural Gas
Fuel Control Valve Assembly



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The Y&F 9200 Series

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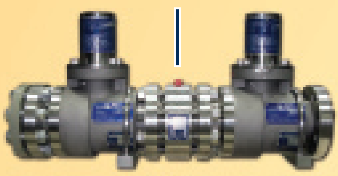

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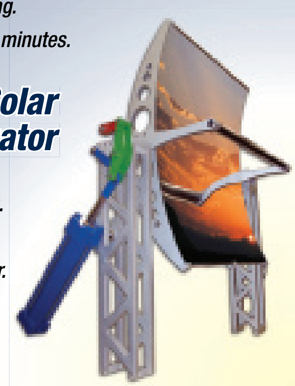

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- Motive force is provided by a single hydraulic cylinder.
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The bottom line: Over the full 20-yr survey period, the duty cycle of "E" class units has remained relatively consistent across all metrics.

"F" class. Fluctuating service hours characterized the years 1991 through 2000. "F" class technology was introduced to the market in this period and the data provide some interesting insights, as follows:

- From 1991 though 1995, (1) service hours fluctuated from a high of 6500 to a low of 3300; (2) hours per start ranged from 233 down to 90; and (3) production averaged over 728,700 MWh.

  During the next five-year period (1996-2000), service hours declined to just over 3870. A substantial change in mission was reflected by the decrease in average service hours per start to just over 50.

  This metric, together with an increase in annual starts to more than 90, suggest that "F" class engines typically operated in a cyclic duty cycle during the last five years of the 20th century. Interestingly, power production decreased by only 4% during the period.
- From 2001 through 2010, the operation and duty cycle of "F" class turbines can be characterized as "more consistent year over year." Service factor ranged from 50% to 60%, averaging about 55% on an annual basis. Production increased to more than 850,324 MWh annually. These units clearly remained in cyclic duty service with 60 to 90 annual starts and from 44 to 60 service hours per start.
- The reliability performance of "F" class units improved year over year. Annual trips dropped from an average of 18 to just over four during 1991-2000 and to between two and five from 2001 through 2010. The size of "F" class engines contributed a longer time-to-repair (average of 80 outage hours per trip) compared to "E" and aero units.

Clearly, the market expects units that can start faster and more frequently, and stay online for shorter missions across all technology classes. And this holds true for units in combined-cycle applications, as well as simple-cycle.

Customers will demand more challenging missions in the near future, including faster starts and load-following capability—in particular to accommodate "must take" power from intermittent renewables resources (wind and solar). For more on this subject, visit www.integrating-renewables.org. The consequent impacts on component life limits, repair cycles, and maintenance requirement are not fully understood at this time.

Back to the beginning. In 1892, Tesla's first commercial 100-hp, single-phase ac induction motor helped to launch an industry with a bent on product improvement and high reliability. The 99.3% reliability achieved on the first try wasn't too bad.

The electric-power industry definitely has come a long way since then. As a point of reference, a typical 100-hp, three-phase induction motor specified for powerplant service today has a running reliability of 99.82%. CCJ

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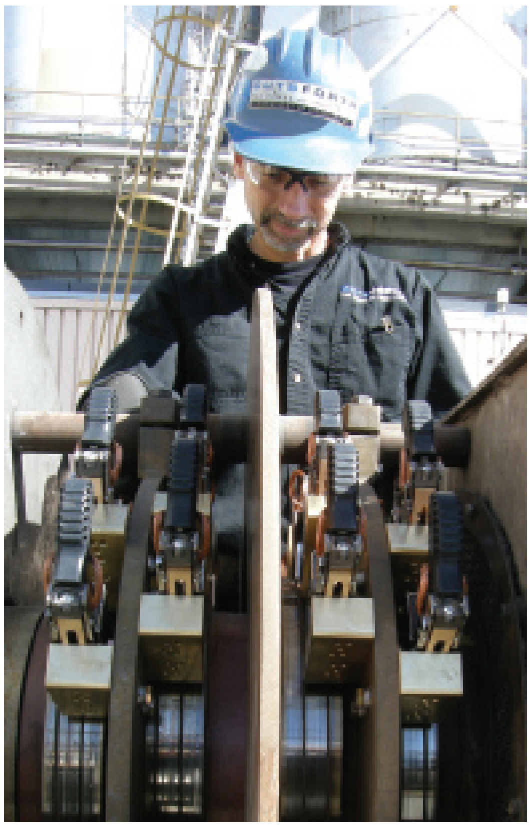

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Best Practices Awards


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Jasper Generating


CCC Saltillo

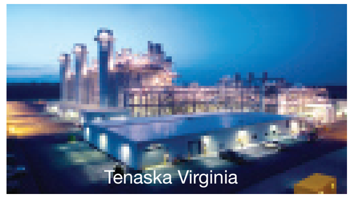

Klamath


Whiting Clean Energy


Morgan Energy Center


Blackhawk


Lincoln Generating Facility


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 2011 awards in Operation and Maintenance (three categories this year: Balance of Plant, Major Equipment, Business), Design, Environmental Stewardship, Management, and Safety (two categories: Procedures & Administration, Equipment & Systems) are presented in the more than four-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 nine members of the CTOTF Leadership Committee, chaired by Bob Kirn of the Tennessee Valley Authority. The Combustion Turbine Operations Task Force, 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 PGA National Resort, West Palm Beach, Fla, April 11.

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.

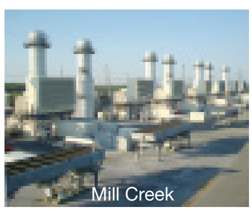
Please judge the entries on your own, using the guidelines and scorecard presented at the end of this report. E-mail Senior Editor Scott Schwieger (scott@psimedia.info) with your choices in each category and tell him why you selected the plants you did. We welcome your input and will include it in the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

Announcement of the 2012 awards program is made elsewhere in this issue. Alternatively, you can get details at www.combinedcyclejournal.com/bestpractices.html. 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 30, 2011. This is one way to get the recognition your plant, your staff, and you have earned by your collective resourcefulness. Please plan to participate.

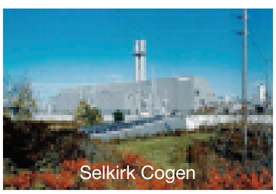

Armstrong Energy

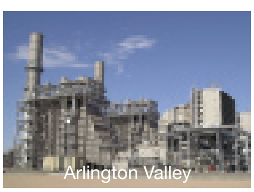

Faribault Energy Park


Beatrice

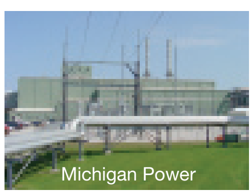

Mill Creek


Hopewell Cogen


Selkirk Cogen


Arlington Valley


Arrow Canyon Complex


Michigan Power


Decatur Energy Center

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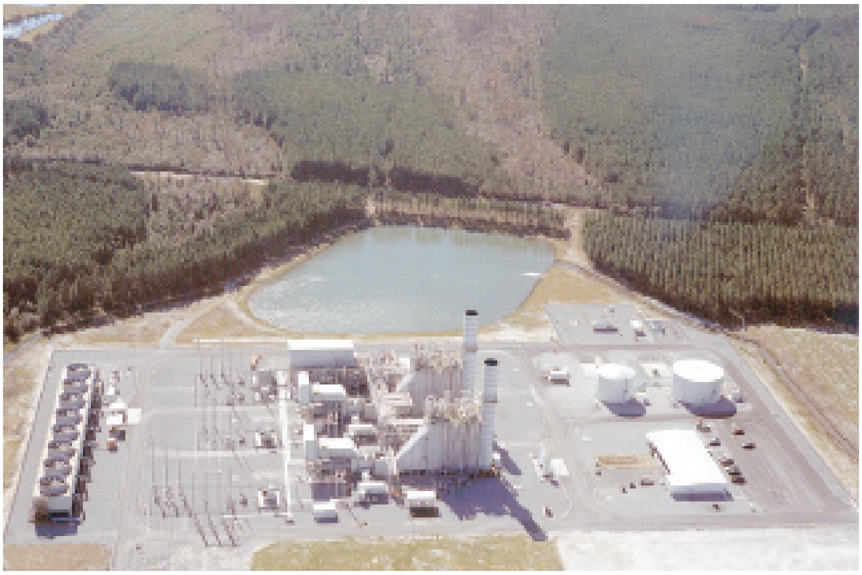


Ammonia delivery mod improves safety, produces savings

Effingham County Power

Owned by ArcLight Capital
Operated by Consolidated Asset Management Services

Challenge. Since commissioning, the plant had ammonia delivered in 300-gal chemical totes for HRSG boiler water treatment. The cost of this product is very high, $1.70/lb, in large part because of the shipping and handling involved. In 2009, the plant used 15,375 lb of ammonia for boiler water treatment at a total cost of $26,138.

In addition to the expense, there also are risks associated with the storage and chemical transfer associated with totes. Plant personnel explored the options available to reduce the costs and the safety hazards associated with handling ammonia.

Solution. The facility uses ammonia for both the ammonia supply to the boiler water and for NO_x control in the HRSG SCR systems. SCR ammonia, delivered by truck at a cost of 13 cents/lb, is stored in two 17,000-gal tanks. From those tanks it is pumped to each HRSG's ammonia skid and then to the ammonia injection grids.

Following verification by independent laboratories that the bulk ammonia was a satisfactory replacement for the product delivered by tote, the plant initiated an engineering effort to modify the bulk ammonia forwarding system to also provide ammonia supply to the HRSG boiler water ammonia holding tank. Only minimal piping modifications were required to implement the design change.

Results. After performing the modification the plant began to see the immediate advantages to this setup. One significant benefit of the new system was that the ammonia is delivered by truck, significantly reducing the chances of a spill by eliminating the need for plant personnel to handle the chemical totes. Additionally, the financial advantage from buying the chemical in bulk is equally impressive.

The cost of bulk ammonia is $0.13/lb versus $1.70/lb for the ammonia delivered in totes. For an annual ammonia usage of 15,375 lb, the amount used in 2009, the plant will save $24,139 per year. With a project cost of less than $20,000, the payback is less than one year and the annual savings will continue through the life of the facility.

Effingham County Power

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

Plant manager: Eric Garrett

Key project participants:
- James Goins, production manager
- Nick Bohl, production manager
- Ken Earl, maintenance manager
- Mark Hopkins, maintenance team leader

Reliable backup for instrument air system

Jasper Generating Station

South Carolina Electric and Gas Co

Challenge. A loss of instrument air pressure is a major reliability concern because instrument-air-dryer purge valves were prone to malfunction, causing a rapid decrease in instrument air header pressure and subsequent equipment upset.

There is also the risk that the backup air compressor can fail to start upon the loss of the running unit, putting the facility at risk. The air compressors and dryer systems are located at the far end of the plant making rapid response and correction challenging. A reliable, cost-effective backup system was desired.

Solution. After an engineering review, plant staff decided to modify and configure the existing, GE-supplied, air processing units (APUs) for use as backup to the instrument air system when 7FA gas turbines are online and operating in Mode 6 (Fig 1). APUs take compressor discharge air, regulate, and cool it for pulse cleaning of the turbine inlet filters.

The instrument-air-system header previously had been tied into the 7FA inlet filter cleaning system (supplanting the APUs) to supply clean,

moisture-free air for inlet filter pulse cleaning because the plant had excess compressed-air capacity and was experiencing ongoing maintenance problems with the APU regulators.

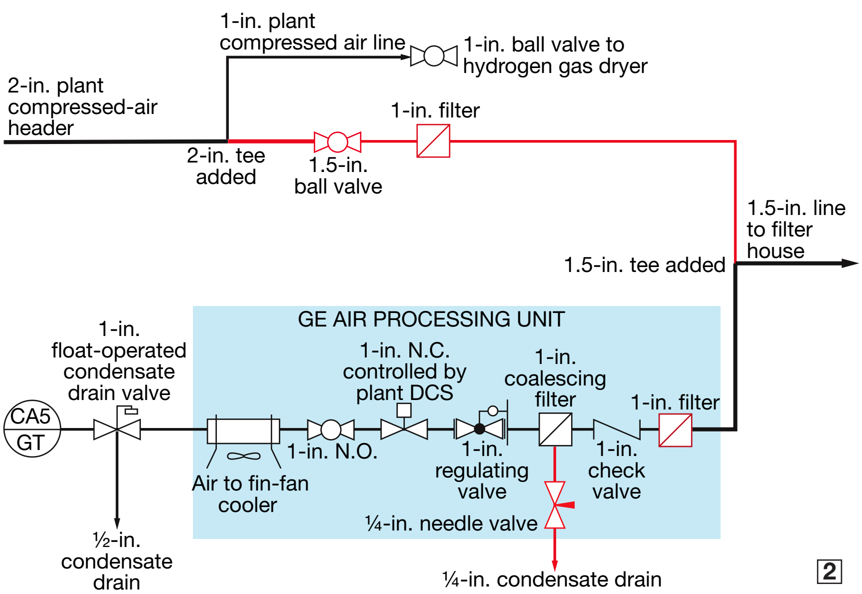
The existing APU control logic was reconfigured into the Ovation DCS to "open" the corresponding APU blocking valve and allow its compressor discharge to provide backup to the instrument-air-system header when header pressure decreases to 90 psig and the respective gas turbine is operating in Mode 6.

1

Excess moisture is removed by an existing inline drain trap on the 7FA side of each APU air cooler and a modified inline filter with draining capability on the header side of each APU cooler. Hot compressor discharge air also is cooled by the existing cooler on each APU prior to admission into the instrument air header (Fig 2). Existing APU moisture-separation towers are bypassed, as the moisture drains are sufficient for short-term, emergency service.

Results. The facility's instrument air system is backed up by each gas turbine's compressor discharge in the event of a low air-header pressure condition when the gas turbine is operating in Mode 6, eliminating the risk of a plant trip and/or equipment upset.

This design change also allows a safe, measured response to air compressor and dryer malfunctions when personnel are not in the immediate area. Modifications were implemented by plant personnel with some minor material costs. Since implementation, one plant trip was averted when a dryer purge valve stuck open and the idle air compressor failed to start.



2

Jasper Generating Station

910-MW, gas-fired, 3 × 1 combined cycle located in Hardeeville, SC

Plant manager: Steve Palmer

Key project participants:
Tim Glover, operations superintendent
Kevin Croft, E&I supervisor
Rusty Mezel, maintenance superintendent

W501F igniter cable failure

Klamath Cogeneration Plant

Iberdrola Renewables

Challenge. For years we have fought the battle of our igniter cables melting at the igniter connection. It became so routine that we developed a plan to replace these at every maintenance outage to ensure reliable operation until the next outage. The root cause was the excessive heat surrounding the igniter.

The insulation can sag, cause an oven effect, and bake the igniter. The igniter cable has a Teflon® end on it that fits into the igniter itself. This Teflon® and silicon rubber seal both melted in the igniter and made it impossible to separate the two, essentially destroying them both.

Solution. The goal was to try to keep the igniters cool. The igniters are located at the bottom of the

Klamath Cogeneration Plant

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

Plant manager: Ray Martens

Key project participants:
- Greg Dolezal, maintenance manager
- Bruce Willard, operations and engineering manager
- Sig Gonczeruk, senior maintenance technician

machine so keeping the insulation tightly secured can be a challenge. Pins attached to the combustor case are used to hold the insulation in place but these pins can fail or can be broken off by workers during maintenance intervals.

We ran a test on one of our units. Two steel pads per igniter with tapped and threaded holes were welded to the case. A 6 × 7 in. steel box was fabricated from two pieces of channel iron and mounted to the pads around the igniters by using some all-thread. The insulation was then packed around the outside of the empty box.

The test worked and the igniters within these boxes did not fail while others did. However, we felt it undesirable to weld on the case so we tried other ideas. An extension was added to the igniter in order to move the cable connection outside of the insulation. This showed some promise but did not completely solve the problem on its own.

Our box test was conducted using the two-layer system provided from the OEM (Fig 3). This insulation was old, had been removed and replaced many times, and was falling apart. We felt that a new single layer system would provide better protection and solve the issue.

Even after going to a new, single-layer insulation system we still had a dead space between the insulation and the case that would heat the cable. An attempt was made to stuff the gap with insulation in order to protect the cable connection, but it proved ineffective because it simply held the heat in (Fig 4).

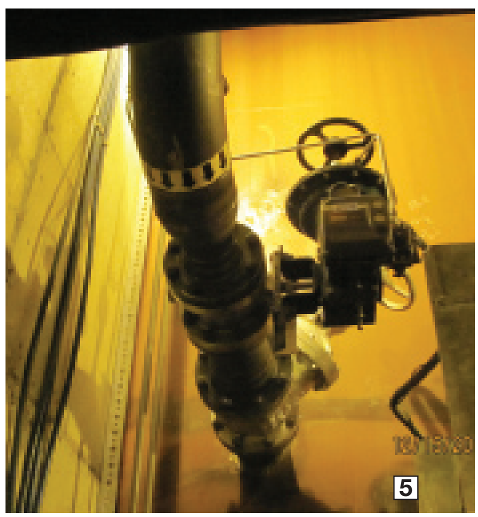
The single-layer manufacturer was contacted in order to build a box, similar to ours, out of insulation material. This proved ineffective as well because it attached to the outside of the single layer and could not provide a tight seal to the case. Heat would then bleed through and cook the igniter.

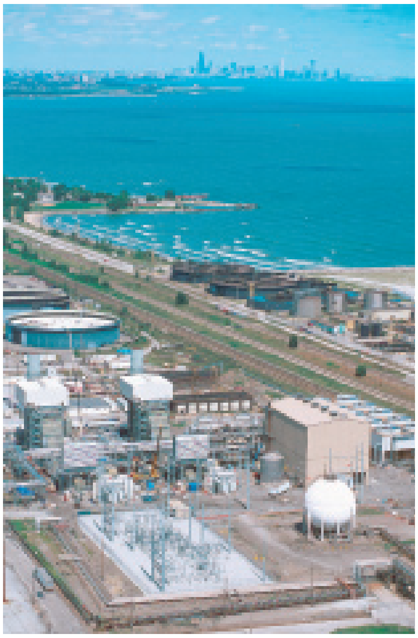
The final solution was to modify the single-layer pads to accept the steel boxes. The boxes were mounted around all four of the igniters. Insulation was stuffed around the boxes but nothing inside. We also modified the test boxes to include a 3-in. lip on the exterior to capture the single-layer insulation better.

Since the igniter extensions showed promise, we simply purchased longer igniters directly from the manufacturer. The ambient air of the turbine enclosure has proven to keep these igniter cables cool enough to provide longer life.

Results. The first test boxes were installed in spring 2008. The remaining boxes were added last spring on the second unit. We have not experienced any igniter failures in any of these boxed areas. We now spark check the igniters at regular maintenance intervals but do not wholesale change them.

Additional benefits include the ability to remove the igniter without removing the insulation. The mounting bolts are readily available with a long extension. The operators like them as well. They are required to check freedom of movement prior to any start. This new system allows them to reach up and conduct the check without sticking their arm into the insulation or pulling on the cable.





Treated water supplied to hotwell

Whiting Clean Energy
BP

Challenge. Water flow from the condenser to the HRSG preheaters must equal export steam flow to the refinery, our steam recipient, to maintain a proper water balance and condenser level. Recent changes in operating envelopes exceed original design specs, requiring excess steam to be bypassed to the condenser. These new operating conditions have created negative impacts on cycle efficiency.

Whiting Clean Energy

525-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Whiting, Ind

Plant manager: Richard Maroney

Key project participants: Full team effort

Solution. An engineering review was conducted and plant personnel installed a 6-in. treated water makeup line to the hotwell (Figs 5, 6). Although this may seem obvious or simple to a casual observer, the undertaking of this project from a design perspective was challenging indeed.

To achieve the modification, given the limitations of the existing facility and requirement for reliability, a thorough understanding of the plant design limits, mass balance, and operating procedures was required.

Results. Installation of a treated makeup water line and control valve to the hotwell effectively reduces the dumping of excess steam by nearly 130,000 lb/hr and saves 175-million Btu/hr of natural gas.

Gravity-filter nozzle support design

Morgan Energy Center
Calpine Corp

Challenge. Morgan Energy Center (MEC) awarded the OEM a contract to refurbish one of four gravity water filters (Fig 7). Complete refurbishment of the one filter included replacement of all media and nozzles. Since then the site has been troubled with nozzles detaching from the lat-


6


7

Morgan Energy Center

800-MW, gas-fired, 3 × 1 combined-cycle cogeneration facility located in Decatur, Ala

Plant manager: Mike Gough

Key project participant:
Scott Parker, operations manager

erals, allowing filter media to enter and plug the backside of other nozzles thus reducing the efficiency of the cleaning cycle.

The plugged and or missing nozzles resulted in:

- Reduced filter operating hours.
- Filter downtime to evacuate media to replace the liberated nozzles.
- Increased filter maintenance.
- Poor water quality.
- Reduced filter throughput.
- Reduced filter cleaning caused by media bed compaction.
- Excessive fines accumulation.
- Channeling.

These combined effects severely hampered production of filtered water.

Solution. A design was engineered and tested for durability and flow restrictions that would eliminate nozzle liberations without reducing gravity-filter performance. This included designing a test header with OEM nozzles and numerous restraint test devices. A solution was found after extensive testing and was implemented in an actual filter.

All the media beds and 450 nozzles from the gravity filter were removed. We then installed new nozzles with the addition of a small amount marine epoxy to each nozzle on the mating surfaces of the nozzle and the lateral.

Then, upon completion of the nozzle installation, we added a Type 304 stainless steel angle ranging from 2 to 10 ft across the top of the nozzles and secured the angle to the bottom lateral header. The media then was replaced over the supported nozzles and filter placed back in service.

Results. This cost-effective design enhancement had immediate positive results. We have not had any nozzles detach from the laterals to date. Also, the unit now has consistent filter cleaning without compaction or channeling.

This design improvement has resulted in increased filter water throughput and increased filter run time between cleaning cycles while maintaining sufficient water quality. MEC plans to apply the same design for the other three gravity filters.

Spill preparedness and response

7EA lube-oil spill-prevention logic mods

Lincoln Generating Facility

Owned by Lincoln Generating Facility LLC
Operated by NAES Corp

Challenge. The triggering event occurred when the unit was on ratchet and there was need to circulate the oil while a kidney-loop oil filtration skid was connected and operating—meaning that the auxiliary and hydraulic oil pumps were in operation. A torque-converter hydraulic oil line failed mechanically and an oil spill commenced in the accessory compartment of the unit. The unit spilled more than 500 gallons of oil onto the compartment floor before the leak was discovered.

The OEM provided a low-lube-oil-level alarm switch, but there was no logic to stop the lube-oil pumps. Unless an operator happens to enter the unit, an event like this will most likely go unnoticed until the low-lube-oil alarm comes in with a spill potential of about 500 gallons. Theoretically, a spill can continue until lube-oil pumps lose suction with a spill potential of more than 2000 gallons. At this volume, oil could potentially end up on the ground.

Solution. Plant personnel discussed the possibility of modifying the logic in the Mark V control system so that a low-lube-oil alarm would automatically select the unit off ratchet, thereby stopping the oil pumps to prevent excessive spillage.

In addition, the discussion yielded a decision to raise the set point of the low-lube-oil-level alarm switch so that only a small change in lube-oil level would annunciate the alarm much earlier than the current setting. The resulting spill would be decreased to less than 100 gallons rather than the more than 500 gallons spilled during the event profiled.

The functional parameters for logic, named "Spill Prevention," to be built into the DCS were as follows:

- Upon the annunciation of a low-lube-oil-level alarm, the unit would be selected OFF cool down/ratchet and stop the auxiliary lube-oil pump.
- Spill Prevention could only be available to the operator during periods where oil starvation to the turbine bearings was not a concern—for example, an extended period of cool down/ratchet during lube-oil polishing operations.
- Spill Prevention had to be manually selectable by the CRO.
- Spill Prevention had to be failsafe in operation.
- The changes could not interfere with any other logic residing in the Mark V controller, except for modifications to the cool-down logic to allow Spill Prevention to turn OFF cool down when enabled.

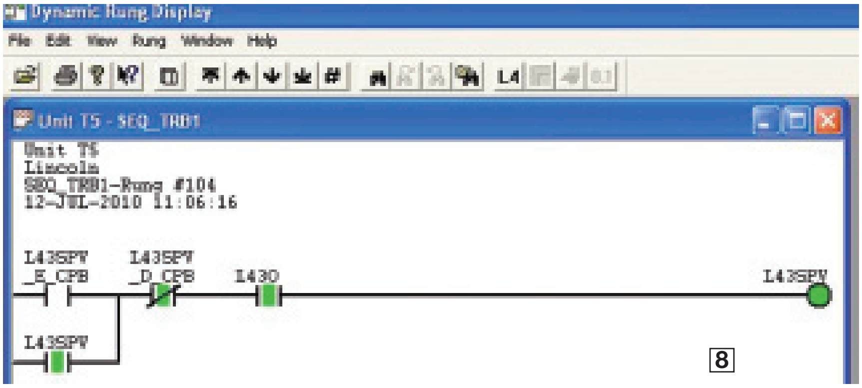
> **Lincoln Generating Facility**
>
> 656-MW, gas-fired, simple-cycle facility located in Manhattan, Ill
>
> **Plant manager:**
> Merle Churchill
>
> **Key project participants:**
> Mark Lane, O&M supervisor
> Nicholas Agos, O&M tech IV
> The entire plant staff

Design and implementation

- A logic block was created giving the CRO enable/disable control of the Spill Prevention logic (L43SPV). Spill Prevention can only be

The staff of Lincoln Generation shows its plant pride. Front row (l to r): Mark Lane, O&M supervisor; Jeremy Escolar, O&M tech IV; Merle Churchill, retiring plant manager; Jeffrey Haun, O&M tech IV; Dan Shelton, O&M tech III. Back row: George Barbeauld, O&M tech III; Kevin Pomykala, O&M tech III; Richard Stoltz, O&M tech III; Nicholas Agos, O&M tech IV; William Sauer, O&M tech III; Brad Keaton, new plant manager

dominate entries



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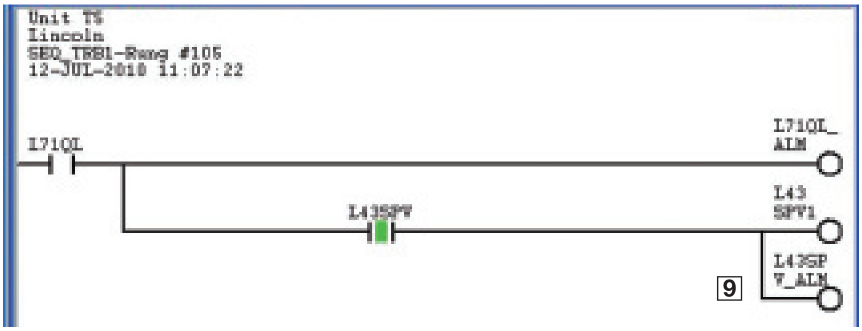

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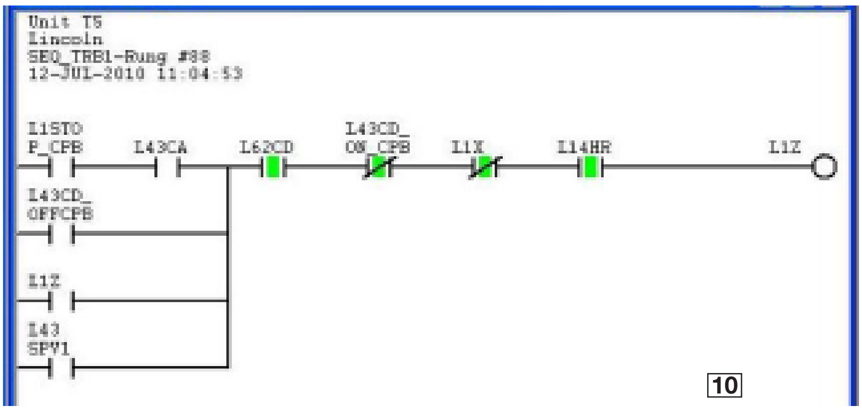

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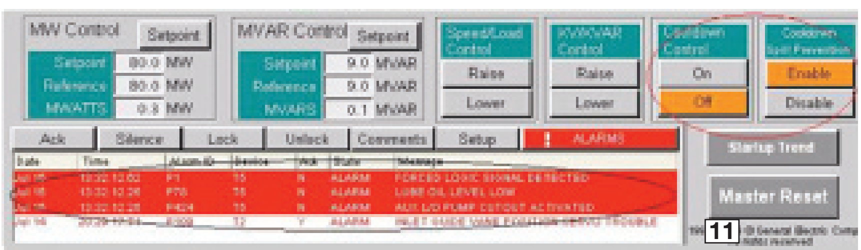

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enabled by the operator when the unit is in OFF mode (L43O). If any other mode is selected while Spill Prevention is enabled, the spill prevention logic automatically disables itself (Fig 8).

- A logic block was modified to use the existing low-lube-oil alarm (L71QL) to activate a secondary coil (L43SPV1) and an alarm (L43SPV_ALM). The additional coils will only be active if Spill Prevention is enabled (Fig 9).
- If the low-lube-oil alarm annunciates, the resulting signal would close a contact in the cool-down logic, energizing coil (L1Z), which shuts down the cool-down cycle and the auxiliary and hydraulic oil pumps (Fig 10).
- A new set of "pushbuttons" were designed for the control room HMI Cimplicity screens to allow the operator to manually enable/disable Spill Prevention (Fig 11).

Results. The low-lube-oil-level alarm switch was reset to 1 in. below the previous level in the reservoir without incident. After the modifications were made, numerous tests were run under a variety of control conditions. All testing proved that the low-lube-oil-level alarm now automatically selects the unit OFF cool down when Spill Prevention is enabled. Oil spill potential is effectively reduced from more than 2000 gallons to less than 100 gallons.

Economical enhancements for spill preparedness

Armstrong Energy
International Power America Inc

Challenge. Spill preparedness can make the difference between a "close call" and a "notification call" to the National Response Center. Affording your staff with some simple but often overlooked strategies and resources will give you a better chance to avoid violations or enforcement actions.

While vigilant inspections and installed containment structures are the first lines of defense, releases may spray and fall outside containment, or mist and be carried by the wind over large areas. Then the rain comes and suddenly one gallon of product can turn into storm water contamination. Next, the agency notifications begin.

On the other hand, if rain is not allowed to hit the product, the whole response would change; plant drainage systems and the storm water remain uncontaminated, and the product is not carried deeper into the soil or groundwater. With effec-

Armstrong Energy

625-MW, dual-fuel, simple-cycle peaking facility located in Shelocta, Pa

Plant manager: Matthew Denver

Key project participants:
Wes Crawford, Jim Mandella, Peter Margliotti, Bryan Miller, and Dexter Cox, plant combustion turbine specialists

tive control and containment, remediation takes place without threat of water contamination.

Solution. One way that control and containment capabilities can be inexpensively enhanced is to stock a supply of 6-mil plastic sheeting in 100-ft rolls. These come in a variety of widths, enabling two or three workers to secure very large areas quickly and effectively. In this case bigger might be better, but weight should also be considered in planning.

While a 40-ft width of sheeting may cover 4000 ft^2, it also tips the scale at 114 lb. Rolls of 6-mil, 20 × 100-ft sheeting are commonly stocked by home improvement, hardware, agricultural, or online retailers and are more easily managed by a single worker if need should arise.

If sheeting is on hand, your staff will find it has numerous invaluable uses, and all for about $29 per 1000 ft^2. Emergency containments, securing of remediated material, and diversion of rain or product flows are only a few of the many uses a responder will find for this product.

A second layer of protection which can quickly be deployed to stop migration and provide containment is the inflatable pipe plug. Each plug covers a range of pipe sizes, allowing just a few carefully selected plugs to cover virtually any contingency. Since many plugs require only 10 to 36 psi of inflation, an inexpensive portable air tank, equipped with a simple gage manifold, works well for most deployments (Fig 12).

For inflation of large or multiple plugs where compressed air is unavailable, a small nitrogen cylinder and regulator can achieve the task. We have found these plugs reliable even in challenging conditions such as storm-water drainage systems.

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When plugged as a precaution, storm drains become emergency containments affording staff the opportunity to inspect for contamination before release (Fig 13). A contamination-free inspection will validate the effectiveness of your control and containment efforts and prevent release should those efforts fail.

The safety and effectiveness of plug deployment can be improved by implementing a few simple strategies:

1. Tie-off the plug prior to insertion; this will prevent migration during a release. Failure to do so could allow the plug to travel downstream and possibly jam in an undesirable location.
2. We recommend leaving an air line attached to the plug and leading out of the space throughout the period of deployment. This prevents the need for personnel to enter a dangerous space (such as a drop inlet or manhole) when installing or removing a plug. Additionally, plug fill pressure may be remotely monitored and adjusted to prevent an unexpected release.


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3. To prevent a surge of water when releasing plugs in large diameter pipes, it may be advisable to instead purchase a "bypass plug." This type of plug is formed with an open pipe of smaller diameter (a bypass) in the center. The bypass pipe is then secured with a second inflatable plug and air line (for submerged applications) or may be fitted with a valve (in above-surface effluent end applications).

Results. The capability, versatility, and ease of deployment which these strategies provide will far out-weigh their low cost. When it comes to spill response and preparedness, options such as these may be the difference between managing a situation and falling victim to it.

Equipment, training key to effective facility response plan

Jasper Generating Station

South Carolina Electric and Gas Co

Challenge. With the potential to store 3.6-million gallons in its three fuel-oil tanks, the plant was required by EPA, citing the Oil Pollution Act of 1990, to develop a facility response plan (FRP) and meet certain response criteria. The plant is adjacent to a major river, with a National Wildlife Refuge downstream, and the intake to a public drinking water source, as well as myriad wetland areas.

Jasper Generating Station

910-MW, gas-fired, 3 × 1 combined cycle located in Hardeeville, SC

Plant manager: Steve Palmer

Key project participants:

Pete Pye, Environmental & safety specialist
Rusty Mezel, maintenance superintendent
Tim Glover, operations superintendent
Mark Ferguson, SCANA environmental

The plant was required to mount a credible response to any size oil spill until the contracted oil spill response organization (OSRO) could arrive on scene. This included a requirement to commence boom deployment in the river within one hour of a major spill.

Solution. The containment area (berm) around the fuel-oil tanks was designed to hold the entire contents of the three tanks in the event of catastrophic failure. An FRP was developed, critical response equipment was procured, and training conducted.

Equipment includes:

- Two outboard motorboats to deploy boom in the river and scout for oil (Fig 14).
- Two large, enclosed spill trailers to hold hard (1000 ft) and soft oil spill boom, personal protective equipment, an oil skimmer, air compressor, and other critical first-responder items (Figs 15-17).
- Two pickup trucks to pull the boats and spill trailers. These are used for other plant duty when not deploying spill equipment.

Annual refresher training is conducted, as well as a tabletop exercise and semi-annual boom- deployment simulations on the river. The contracted OSRO is involved in all of the deployment exercises to cement the relationship and test the plan.

Results. An EPA FRP audit conducted onsite resulted in no significant findings. Auditors stated that the site was a "model" for preparedness and should be used to train other

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organizations. They were particularly impressed with the spill trailers and our training regimen. Plant personnel are able to deploy boom on the river within 45 minutes of a spill scenario. The OSRO is able to deploy resources to the plant within two hours.

Organizing hazardous and flammable wastes has many benefits

Faribault Energy Park

Owned by Minnesota Municipal Power Agency
Operated by NAES Corp

Challenge. Faribault Energy Park was built as a model of environmental responsibility and innovation and has been welcomed as a long-term asset to the community and a good environmental neighbor.

> **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

So when plant staff recognized various drums of new oil, waste oil, boiler and cooling tower chemicals, water-wash soap, and oily waste on small containments throughout the plant, they were determined to organize these hazardous and flammable materials to prevent potential accidental spills.

Solution. The O&M staff, led by Doug Klar, purchased a two-story hazardous and flammable waste containment building to organize and retain all hazardous and flammable waste, and to store extra chemicals and flammables (Fig 18). This two-hour fire-rated structure meets all state codes and has the following specifications:

- Dimensions: 5.5 × 30.5 × 10-ft high.
- Weight: 11,435 lb.
- Walls: 14 gage steel.
- Roof: 12 gage steel.
- Sump: 10 gage steel.
- Equipped with six doors and a three-point locking system.


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- Finish inside and outside is a chemical-resistant urethane paint.
- Design meets Factory Mutual Standard 6049, "Flammable and Combustible Liquid Storage Buildings."
- Warranties: five years, structural; one year, coatings and accessories.

Purchased from Safe Buildings Corp, Chicago, Ill, the structure is located on a concrete pad and includes the following additional features:

- R11 insulation.
- Rain guard.
- Aluminum grate, non-spark flooring.
- Natural ventilation with adjustable backdraft dampers.
- Seismic 1-in. tie downs.
- Static ground connections.
- Forklift pockets.
- NFPA 30 sign.

Each compartment within the building is separated by a two-hour fire-rated UL 263 wall and contains an isolated sump with a capacity of 396.4 gallons (Fig 19). Each compartment can accommodate four drum pallets (two wide and two high), assuming the skids are 48 × 48 × 42.5 in. high. The building has a 10-in. spill containment system throughout the interior and is supplied with:

- 120-V power.
- A 60-amp main panel equipped with a 60-amp breaker.
- Three Class I, Div I, explosion-proof heaters.
- Three Class I, Div I, explosion-proof interior lights rated 300 W with guards and one exterior switch.
- One weatherproof, four-space duplex-grounded GFCI receptacle (exterior mount).

Results. Plant chemicals, flammables, and wastes are now neatly stowed in a weather- and spill-proof storage area. Purchasing and installing the building cost little more than the expense associated with having a hazmat spill response team come onsite and clean up a minor spill. Not only is the plant safer and tidier, containing these materials makes all the difference in maintaining the environmental-stewardship goals of the facility.

Plant personnel have been recognized for their efforts in meeting, and exceeding, environmental stewardship goals and regulatory compliance in a timely and efficient manner. It was their dedication, persistence, and innovative solutions that brought the plant to such a high level of performance.

Improve plant communication, document control with SharePoint®

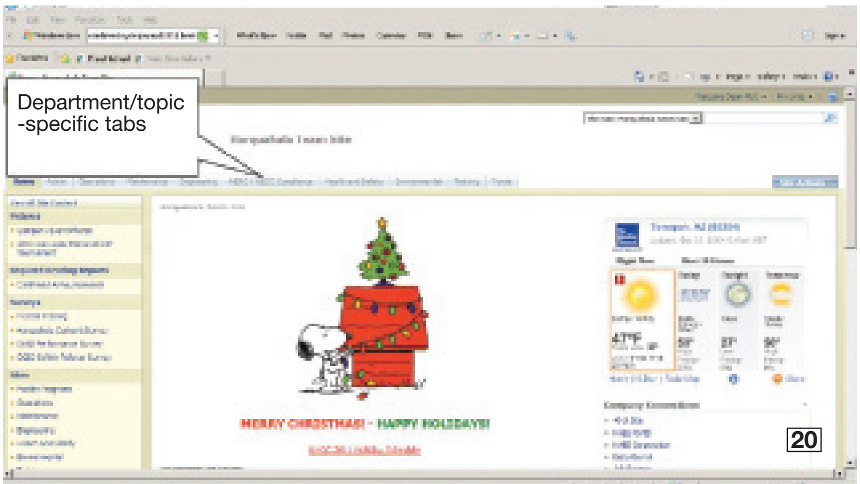
New Harquahala Generating Co LLC

Owned by MachGen Holdings LLC
Managed by Competitive Power Ventures
Operated by NAES Corp

Challenge. New Harquahala, which began commercial operation in September 2004, sells its capacity and energy into the WECC market. To meet the intent of the "care, custody, and control" provisions of today's insurance policies, facility management identified an opportunity for improvement with plant-wide communication and document control. After conducting internal discussions on both topics, the management team decided to use "technology" to assist it in goal attainment.

Because the plant is a pure merchant facility, operating in the very competitive Southwest electricity market, it needs to use as many cost-control mechanisms as possible. This approach results in a lean staff of highly qualified personnel who have to work as efficiently as possible to achieve the targeted performance that allows them to compete.

Outside of the technical challenges of operating a facility of this capac-



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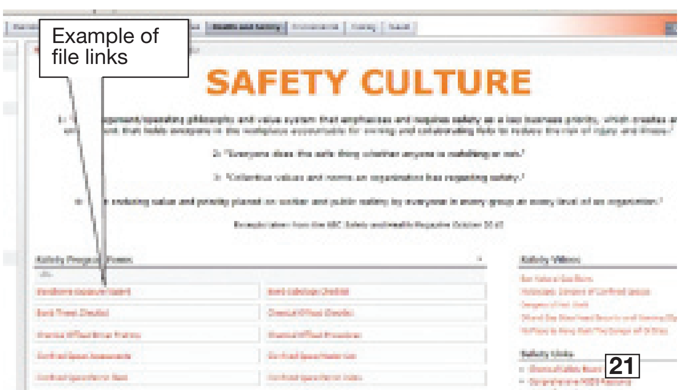

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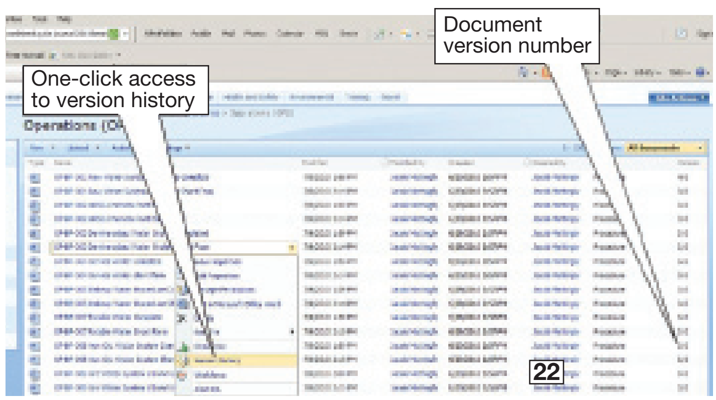

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New Harquahala Generating Co LLC

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

Plant manager: Dean Motl

ity with a lean staff, communication of goals, plant schedules, administrative activities, and document control can be a challenge when approached with conventional methods.

Solution. After conducting a review of available options the team decided to develop a facility-dedicated Microsoft SharePoint® (SP) intranet site. Its goal: Establish a centralized information hub that would incorporate document storage as well as provide a communication interface which was user friendly and reliable.

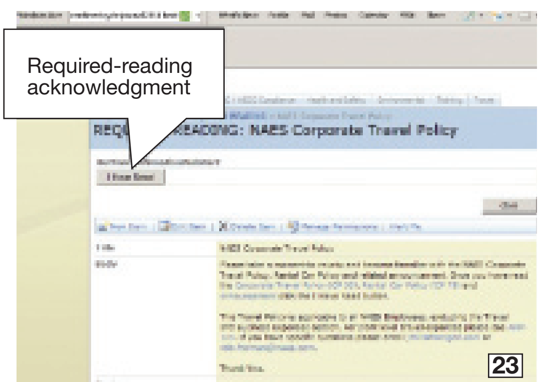
Some of the primary benefits to the use of SP are:

- Provides simplified query tools for locating technical and administrative documents.
- Ensures that all documents are archived in one location with consistency.
- Secures information storage by backing up all files both locally and remotely on servers every 10 minutes and enlists a hierarchy of user rights that allows for easy management of documents.
- Integrated web features allow the plant to move closer to a paperless work environment.
- Centralizes file storage, which allows a single file to be accessed from multiple links on the same website.
- Integrates version control that eliminates multiple revision copies of the same document.
- Site specific required reading, polling, and voting interface.
- Encrypted remote access for corporate management.
- Low cost of implementation.

How the facility would implement SP was closely reviewed to ensure that the desired goals were achieved cost-effectively. Bids from outside contractors were considered but were rejected both on cost and limitations to site-specific customization. The plant decided to use its internal resources and sent two department heads to SP training and brought in a SP consultant/trainer for one week to facilitate the initial site architecture and layout. Once that was accomplished the team began the development of the topic/department specific web pages (Fig 20).

In the next phase of development, the site was configured to utilize linking methodology, which allows for single document locations and document "versioning." The linking function prevents multiple copies of the same document and allows all users to access information within several clicks of the mouse once SP is accessed through the web browser (Fig 21).

The versioning feature of SP is one of the software's powerful tools. It eliminates the need to save copies of multiple versions of files that are frequently edited by several parties



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and allows users to access previous versions of the file and recover historical document information that otherwise would be lost (Fig 22).

Document security also was a concern that needed to be addressed, because there are many vital documents that a powerplant must retain—such as contracts, permits, drawings, outage and maintenance reports, etc. The server back-up functions and offsite archiving of SP are superior to that of conventional server back-up methods.

Additionally, access control to certain documents can be easily administered via the user level access functions of SP, which essentially allows the SP administrator to set access and editing rights based on specific needs. Access rights are infinitely customizable and can be established in groups or adjusted for each individual.

Another key tool that comes integrated with SP is the ability to set up surveys, polls, and read acknowledgement functionality. Prior to the implementation to SP, the plant had a "Required Reading" program that provided a mechanism to ensure all important plant announcements, procedural changes, or governmental regulation correspondence was clearly communicated and acknowledged by each employee.

With the tools available in SP, the administrator can easily post a survey, poll, or read- acknowledgment link which each employee can then interact (Fig 23). In the case of the read- acknowledgment function, SP maintains an electronic roster of all employees who have read and acknowledged the vital information that plant management is trying to communicate with the crew. This is not intended to replace formal face-to-face procedure review and training but does provide excellent documentation of communication.

Results. The design, implementation, and activation of the entire site took approximately six months—January to June 2010—with approximately 300 man-hours split between two department heads. With the time savings for document retrieval, information access, and ease of communications the facility believes that this will be easily recovered within one year of implementation.

Additional ancillary benefits have already been realized, highlighted by the highly favorable impression that it has presented to two different regulators conducting routine inspections. They commented on the significant time saving associated with presenting documentation for their inspection efforts. Both also agreed that the facility demonstrated commitment to a culture of compliance by ensuring that regulatory documentation was kept orderly and easily accessible to the plant personnel.

In summary, the plant believes that this project will provide long-term benefits with all aspects of communication and document control. It will support the desired goal of centralized electronic storage and archiving of critical data, and promote efficiency for the team. By taking ownership with the development, design, and layout of the site, the team has customized a tool that fits the plant's specific needs, without trying to force a canned product to fit what they were trying to achieve.

There are still many features and more functionality to be added and incorporated over time, but the solid foundation that has been set will facilitate all future additions. Management already is seeing benefits of the system that it didn't foresee and is confident that as more time is spent using the interface that more great ideas for improvement are only a click away.

Using Microsoft SharePoint® to plan, collaborate, and organize

Arlington Valley Energy Facility

Owned by LS Power Group
Operated by NAES Corp

Challenge. Many combined cycles are faced with minimal staffing and a majority of the personnel remain on rotating shifts. This creates an environment where word-of-mouth communications with all hands in a timely fashion is not possible because people are on different schedules.

There also are several other information-management needs, such as: keeping plant written programs on the most current revisions, tight outage scheduling, and perpetual training coordination. If a plant is to adapt and thrive in this fast-paced environment, it must always be looking for ways to improve information flow, manage human capital, and create a collaborative team environment.

Solution. The plant decided to utilize Microsoft SharePoint® (SP) as a tool to collaborate more effectively and in an efficient and cost-effective manner. The SP server application

Arlington Valley Energy Facility

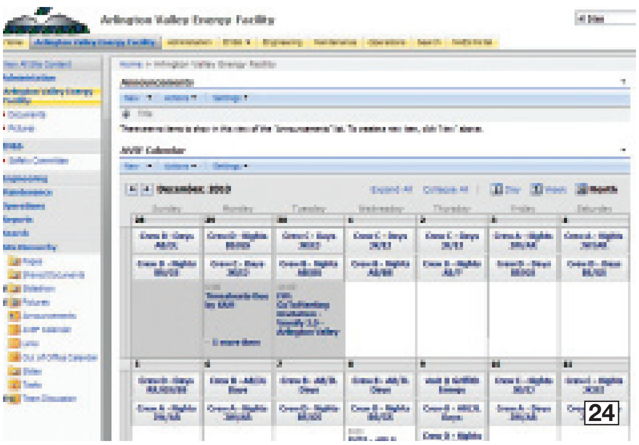
570-MW, gas-fired, 2 × 1 combined cycle located in Arlington, Ariz

Plant manager: Greg Nugent

Key project participants:

Ron Sager, production manager

Arlington Valley O&M staff



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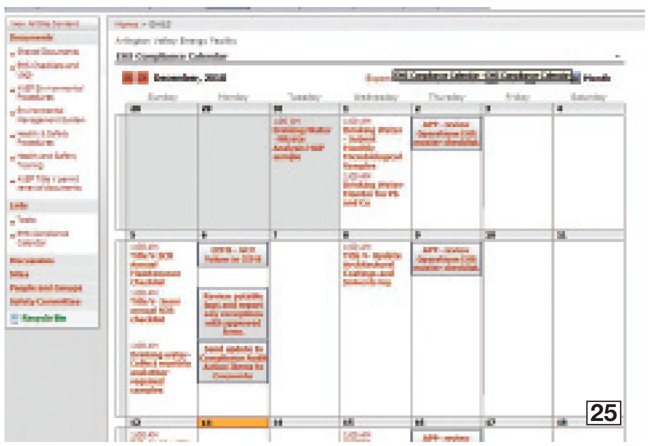

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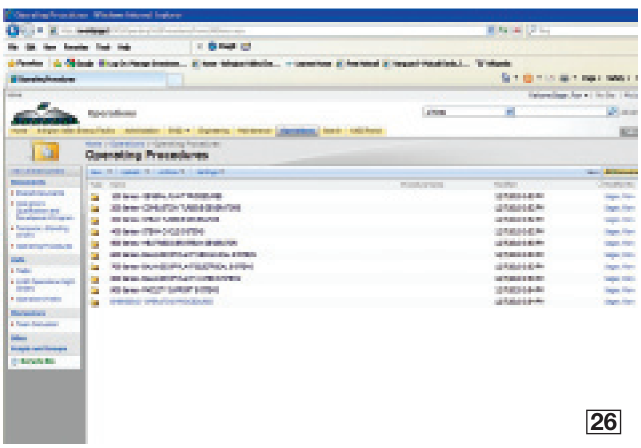

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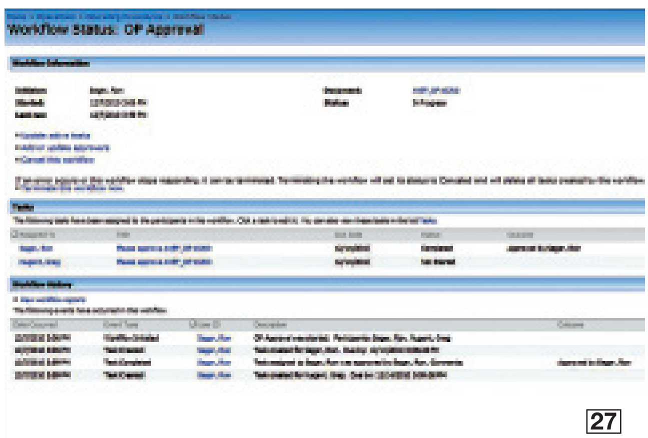

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allows the end user to create customized intranet site architecture to fit the structure and needs of the organization. We chose to arrange the site into a main home page for all plant personnel and then create pages for each plant department. The following are some of the capabilities designed and implemented into Arlington Valley's SP site:

1. Plant-wide information. The intranet home page is a voluntary start page for all site personnel. It has general content such as a site calendar, air-quality status, area news headlines, and announcements section (Fig 24). Each page has a links section containing useful sites: medical, dental, vision, and 401k employee benefits. There also are industry links—such as for CMMS, safety, users group forums, etc.

2. Scheduling:

- A site calendar on the home page has a schedule of major events, out-of-office notices, and on- duty shift assignments.
- Compliance event calendars for NERC and EH&S have been configured to allow for completion comments, current job status, allow for new tasks, recurrence and rescheduling of tasks, and allow tasks to be marked complete so the task is filed and is removed from view (Fig 25).
- An operations schedule allows for shift tasks to be assigned with just a few clicks. The tasks disappear from the list when complete and are archived with the tasks completion comments.

  There is an outage schedule that allows for a conventional calendar or Gantt charts.
- Calendars can be linked to Microsoft Outlook®, and can be overlaid with other calendars. Calendar events can be added and edited from Outlook® or an incoming email configuration can be configured to allow calendar events to be sent as attachments from email.

3. Document control. Document libraries containing procedures, policies, and standard forms require content approval, have automatic versioning control and recordkeeping, and have configurable workflows that allow automated procedure-change approval routing and documentation of change notification to the affected audience (Fig 26). Such an arrangement allows a procedure, for example, to be posted in its original file format but maintain document revision protection.

This allows the end user to check out and revise a document without any other users seeing the changes, while letting other users know the document is checked out. The document is checked in once the revision is completed. The document library then asks for revision comments which will be appended along with the revision in the permanent revision record.

A configurable automatic-approval workflow then starts and routes the document sequentially to the appropriate management approvers (Fig 27). Once this is completed, it automatically approves the revision and is made available for viewing or printing by users. The approving manager can also initiate a workflow that gathers signatures of the affected audience. The configurable email within SP sends workflow emails based on a user-specified completion time frame until the task is completed.

4. Training. The need exists for various small training packages to be passed around for review. SP allows users to post PowerPoint® files, videos, or sound files and create a workflow to collect signatures as proof of training. Email routing of assignments and reminders are all automatic once the workflow is initiated.

5. Safety. The SP intranet site allowed us to create a home for plant interface with the safety committee. In this site, personnel can give safety suggestions and view the status of past suggestion action items. The site committee uses a calendar function to plan and track meetings.

Results. While improvement results are mostly subjective, most personnel agree that the intranet site has made their jobs easier by:

- Making a "home base" where all master copies of procedures, checklists, and policies can be found.
- Creating a place where staff can verify their schedule at a glance and keep abreast of plant events.
- Producing a way to manage documents while keeping them editable by the end user. This allows simple and efficient procedure change approval routing.
- Forming a way to document training on procedure changes and other events.

Reports show our site usage has increased over time as people became accustomed to it and realized its value. We found that amplified site use was also recognized when we added some general interest items such as current weather, news events, stock prices, and even a daily Dilbert cartoon.

Training, developing plant engineers

Arrow Canyon Complex

Harry Allen, Silverhawk, and Chuck Lenzie Generating Stations
NV Energy

Challenge. With no standard job description or development plan for new engineers assigned to powerplants, plant engineers were often focused on different activities from plant to plant with little or no direction. Their activities were related to management's "concerns of the day" and were often reactive in nature. Plant engineers often were overwhelmed by the day-to-day demands on their time while still not meeting management expectations.

Solution. Engineering management worked to establish a standard job description and development plan that features clearly defined and measureable duties and responsibilities for plant engineers. Plant engineer duties and responsibilities were defined as follows:

- Management of change (MOC) coordinator: Monitors the status of all active MOC items and has overall engineering control and oversight of all design changes, modifications, and retrofits.
- Availability improvement process (AIP) facilitator: Reviews and analyzes NERC GADS unit availability data, monitors the active AIP action items and the progress of AIP teams, and provides technical and engineering support for AIP action items and assists AIP team efforts.
- Insurance risk management coordinator: Acts as the insurer's point of contact for the generating plant, coordinates the insurer's site visits and activities, and tracks and monitors the insurer's risk recommendations.
- Responsible for capital projects: Develops business cases, monitors and tracks the status of all open projects, reviews and updates the monthly capital variance report,

and provides technical direction and oversight for corporate project engineers and contractors.

- Responsible for document control program: Tracks revisions to controlled plant technical documentation, drawings, P&IDs, instruction books, control logic, and site plot plans; ensures that drawing and document changes and/or revisions are captured using the MOC process and updated in the document archives; and maintains a status log of all document additions, updates, and/or revisions.
- Engineering assistance to plant personnel: Assists O&M personnel in resolving plant technical issues, provides technical analysis to assist management with economic O&M decisions, and assists management with the determination of root causes and the development of corrective actions.
- Assist with planned outage work scopes and schedules: Contributes to the technical development of planned outage work scopes and schedules and provides technical oversight during inspection and maintenance evolutions for critical plant equipment.
- Assist management with inspection and permitting of regulated equipment: Ensures all boiler and pressure vessel operating permits are up-to-date, tracks and schedules all boiler and pressure- vessel permit inspections, and monitors the performance of equipment inspections, code repairs, NDE, and safety valve maintenance.
- Support company and plant safety programs: Provides engineering and design support as needed to resolve plant safety issues.

Arrow Canyon Complex

Chuck Lenzie Generating Station
1100-MW gas-fired, two-unit, 2 × 1 combined cycle

Silverhawk Generating Station
520-MW gas-fired, 2 × 1 combined cycle

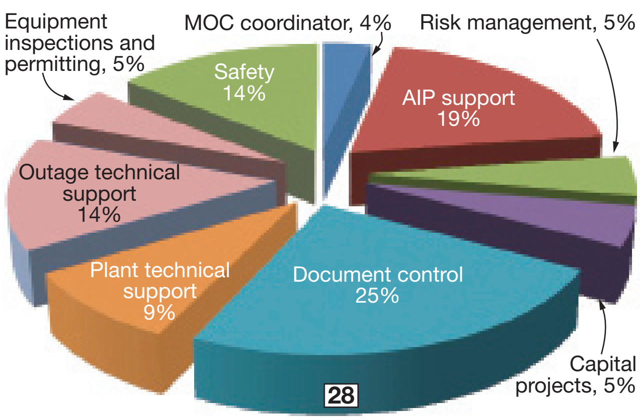
Harry Allen Generating Station
630-MW gas-fired, 2 × 1 combined cycle and two simple-cycle peaking units

All the plants above are located near Las Vegas, Nev

Regional director: Tom Price

Key project participants:
David Hall, engineering manager

How a plant engineer spends his/her workday



Results. The plant engineer's job duties are now structured, organized, and measurable. There is more accountability for the engineer's activities with a process in place to track and analyze the time spent on their various assignments. Time entry codes were created for each of the nine categories above so the engineer's activities could be tracked and analyzed (Fig 28).

Managers and supervisors can now analyze and evaluate the engineer's activities. They can use this information to determine whether the engineer has been favoring a particular assignment, neglecting a duty, or needs additional resources. The engineers provide monthly engineering reports detailing their engineering activities and the status of their primary responsibilities.

Sustainability: Leadership and the triple bottom line

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

Challenge. The challenges of the 21st century are requiring powerplants to fundamentally change the way they operate. Issues such as environmental regulations, competitive advantage, smart grid development, and stricter NERC and governmental requirements are hitting powerplants head on and demanding that attention be paid to aspects of the business beyond quarterly financial results.

Solution. The concept of sustainability addresses all aspects of an organization, including innovation and creativity, where organizations figure out ways for protecting the environment, supporting local issues, and increasing stakeholder engagement, as well as creating a dialog with community partners, suppliers, and customers. The framework to help operate within this sustainability vision is the triple bottom line (TBL) which focuses on people, community, and the environment.

1. Human capital. The facility (TVGS) values human capital because it recognizes that people are assets. The sustainability of the facility's competitiveness is a renewed effort in how talent is used and leveraged. Learning organizations mitigate future labor and skills shortages in two ways:

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
- Donnie Scott, operations manager

Tenaska Virginia: A shining star in the community

- Employees expect organizations to invest in their professional development, thereby enhancing their "employability" within the company or in the job market.
- To address labor and skills shortages, organizations must "grow their own" expertise by providing employees opportunities, both on and off the job, to raise their skill level. TVGS created a succession plan starting with a proactive evaluation of the critical workforce capabilities needed over the next few years.

It incorporated a blended learning methodology consisting of a mix of training elements to achieve a high level of employee training and competency based upon site- and position-specific criteria from the facility's qualification standards manual.

These elements consist of traditional lecture and seminar training, web-based training, on-the-job training, practical-factors demonstration, observed evolutions, systems operations, and performance demonstrations.

By sharing industry best practices, TVGS developed a cost-saving program; attained zero personnel safety incidents or personnel lost time; improved environmental performance, operational efficiency, and availability; and developed an ergonomics program.

2. Community. During the holiday season, employees and spouses donate time and money shopping for toys and clothing for at least 80 county children and elderly (Fig 29). The company matches the employees' monetary donations. Employees continuously donate food to the local food bank. The facility has sponsored quarterly food drives feeding at least 500 guests at a local church. Easter baskets were delivered to 20 children; 15 foster children were given birthday cards and ice cream certificates.

An education-facility partnership was established to provide math tutoring, reading, mentoring, science expo judges, sport teams sponsorships, facility tours, spelling bees, career fairs, Commonwealth scholar instructors, and more. During the United Way's *Day of Caring* employees painted areas around the local middle school.

3. Eco-environmental. The facility established a steering committee to focus the facility's sustainability commitment and quantify the impacts on multiple stakeholders. Three years ago, TVGS started to collect and donate used cell phones for the *Cell Phones for Soldiers* charity. Over 300 cell phones have been donated from within the facility, company, and the community to be exchanged for calling cards to be used by our soldiers overseas.

An eco-environmental program was started to minimize waste to the environment. Aluminum cans and newspapers are collected and donated to local youth groups. Recycled paper is used in the printer, and the printer default setting was changed to print on double-sided paper. Plastic utensils and cups are rarely used, having been replaced with refillable water bottles or porcelain cups. Magazines are read online rather than being delivered to the facility. Junk-mail senders are notified not to send via ground mail. Smart power strips are installed on personal computers and turned off at the end-of-the workday. Office lights are also turned off when not occupied.

Results. Leadership and the triple bottom line are not awards, accreditations, or certifications you can achieve: it's an ongoing process that helps us keep on track towards running a greener business, treating people right, and demonstrates to the community at large that we are working for a greater common good.


Continue the dialogue . . .


PGA NATIONAL

Ammonia-tank leak-suppression system protects personnel, neighbors

Terry Bundy Generating Station

Lincoln Electric System

Challenge. The Terry Bundy Generating Station is a four-unit combined-cycle facility which uses selective catalytic reduction to control NO_x emissions from three LM6000s. SCR is a post-combustion control process in which anhydrous ammonia is injected in the exhaust gas, upstream of the catalyst, to convert NO_x emissions to nitrogen and water. The site's air permit restricts NO_x emissions to 3.5 ppmvd (30-day rolling average).

During the plant's last Risk Management Program review, the potential for a catastrophic spill from a 12,000-gal ammonia storage tank was identified as a major concern. A large release of ammonia from the site has the potential to impact facility staff as well as surrounding residences.

Solution. Plant personnel evaluated the potential for installing an ammonia-spill remediation system to reduce the impact of a tank breach. After reviewing remediation options, a water spray system was identified as the most economical solution. It has 34 nozzles configured on six lines surrounding the tank to provide 75 ft^2 of spray coverage. The system was designed to NFPA 15; spray density is 0.25 gpm/ft^2.

The spray system requires a nominal minimum flow of 700 gpm at 120 psig, which is supplied by the fire pump. Multiple ammonia detectors monitor the site's various ammonia systems and are used to alert plant operators to any releases. As soon as an operator confirms a major ammonia release from the storage tank, the spray system would be activated manually to minimize the size and concentration of the resulting ammonia cloud. Fig 30 shows the final flow test.

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Results. Successful demonstration of the system proves it significantly reduces both risk to plant personnel and the potential for offsite exposure. With the successful demonstration, the utility has budgeted for 2011 the installation of similar systems at the Rokeby Generating Station. It has two large ammonia systems associated with turbine inlet air chillers.

Terry Bundy Generating Station

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

Plant manager: Brad Hans

Key project participants:
- Jim Dutton, operations supervisor
- Vern Cochran, maintenance supervisor
- Tom Davlin, project engineering manager

Eliminating secondary containment entry protects personnel

Klamath Cogeneration Plant

Iberdrola Renewables

Challenge. Plants are often constructed with equipment requiring monitoring and/or service located inside secondary containments. In addition to the hazards posed by chemicals, oil, fuel, etc, within these containments, environmental conditions can fill them with water or even ice.

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Solution. It has been our long-term goal to eliminate the need for personnel to enter these areas for scheduled duties. The first containment addressed was the anhydrous ammonia tank. The initial construction had personnel climbing over the containment wall and then climbing a ladder to get to the top of the tank. Any emergency egress would have been nearly impossible.

Plant staff took the stance that all areas within the reach of an ammonia release needed two means of evacuation. Therefore, we added a stairway on the side of the tank that lands outside of the containment (Fig 31).

The second area of attention was the transformers, which have a nitrogen blanket that requires pressure verification twice a day. On our main transformers, this check can be done from outside of the containment and the surrounding fencing. The auxiliary transformers, used for station service, had the nitrogen bottles inside the containment and out of the operator's view.

At Klamath, transformers are notorious for ice buildup. Deck grating and anchor points were attached to the transformer blast wall. The new location required new tubing runs but allowed us the space to have a spare bottle readily available. We also changed the bottle material from steel to aluminum for ease of handling (Fig 32).

Lastly, since wastewater discharge is sent to the city's treatment facility, the plant is required to neutralize demineralizer regeneration water beforehand. The original design had the pH probe inside the containment near the recirculation pumps. To calibrate this probe, the operator was required to enter the containment area, which at our site, is shared with our sulfuric acid storage tank. Our solution was to change where the pH was sampled, add redundancy to the probe, and design it so the operator does not have to remove the probes for calibration.

As seen in Fig 33, the water enters the building from outside (the containment area), flows upward across redundant probes and is discharged back into the chemical waste sump. The probes were installed in the vertical leg to minimize debris, such as resin beads, from accumulating in the pipe and to ensure the probes stay wet to maintain longevity.

Klamath Cogeneration

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

Plant manager: Ray Martens

Key project participants:
- Greg Dolezal, maintenance manager
- Bruce Willard, operations and engineering manager

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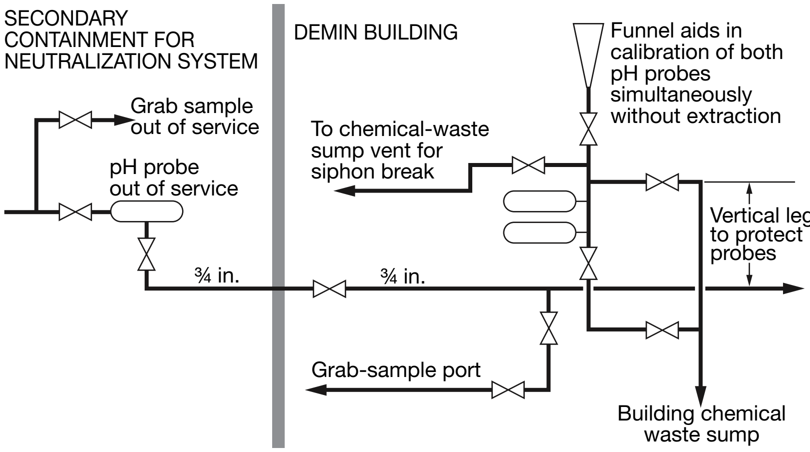

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The probes can also be bypassed while doing online calibrations. A funnel at the top of the vertical leg allows for the addition of calibration fluids without the need to remove the probes. It also allows for the calibration of both probes simultaneously. We also installed a low point drain. Not only can we get a grab sample from this drain but it also allows for the removal of any accumulated resin beads (Fig 34).

Results. The task of eliminating all entry to secondary containments is a work in progress. Below are just three outcomes of how we are trying to remove the need for our staff to enter our secondary containments while performing routine tasks.

1. Ammonia tank stairwell:
- Provides for an easier route for O&M personnel to access the top of the tank.
- Provides a second point of egress.

2. Transformer nitrogen relocation:
- Keeps the operator out of the containment during reading and bottle exchanges.
- Allows for a readily available spare bottle.
- New aluminum bottles are easier to manage.

3. Neutralization pH probes:
- Allow for redundant probes for accuracy and simultaneous calibration.
- Minimize the opportunity for contact of hazardous solutions.
- Move probes away from atmospheric elements.
- Keep operators out of the sulfuric acid containment.

Green Country Energy

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

Plant manager: Rick Shackelford

Key project participants: Linne Rollins, Dave Rose, Carol Wilson, Danny Parish, Phil Pace, Allen Meyer, and Chris Shipman, Green Country safety committee members

Tornado shelters safeguard most valuable assets

Green Country Energy

Owned by J-Power USA
Operated by NAES Corp

Challenge. Oklahoma is typically known for rodeo cowboys, college football, and unfortunately. . .tornados. The state averages 54 tornados per year but has seen activity as high as 145 in 1999. Unfortunately, mobile home parks and powerplants appear to be subjected to more than their fair share of tornado attacks. For example, in years past, significant tornado damage occurred at plants in Muskogee, Anadarko, and Woodward.


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Plants in Tornado Alley have emergency procedures that are employed during a tornado threat. However, offering plant employees a safe shelter during a tornado threat presents some real challenges at newer combined cycles, where most buildings are of corrugated metal siding construction and lack basements. Green Country's goal is provide the staff with reliable shelter when one of the strongest forces of nature threatens their safety.

Solution. The value of storm shelters was never more apparent than in 2004 at the Parsons Co manufacturing plant in Roanoke, Ill, when an F4 tornado obliterated the site (Fig 35). Over 100 workers at the plant during the event remained safe and only minor injuries were sustained. The aftermath of the tornado and locations of the three storm shelters are seen in Fig 36.

Upon learning of and discussing


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the Parsons Co's remarkable safety accomplishment during an F4 tornado event, our safety committee, plant management, and owners decided to purchase and install tornado shelters at various locations throughout the plant.

As shown on the Figs 37 and 38, a 14-person tornado shelter was installed at a central location within the plant (just outside of the Unit 2 electrical equipment room) and a 24-person shelter was installed behind the combined admin building/maintenance shop.

Careful consideration was made to the proximity of high-voltage power lines, and high-pressure piping when identifying the best location for shelter placement. The shelters selected were constructed locally and designed to withstand an F5 tornado and can support over 100,000 lb stacked on top of them, which is equal to about 25 mid-sized cars.

In addition to shelter installation, storm spotter training DVDs were purchased, watched, and discussed during weekly safety meetings. Emergency procedures were also improved to include recommended actions during scheduled maintenance outages, with consideration to a number of contractors who might be onsite during a storm.

Results. Fortunately, the tornado shelters have not been needed since their installation and the plant staff is obviously hopeful they will never be used. However, they certainly provide a significant peace of mind when tornadic storms are in the vicinity of the plant. And, should a tornado ever find its way to the plant, the decision to equip the plant with tornado shelters would undoubtedly be the best decision ever made at this Oklahoma powerplant.

Inlet filter house floor mod increases efficiency, safety

Beatrice Power Station

Nebraska Public Power District

Beatrice Power Station

254-MW, gas-fired, 2 × 1 combined-cycle located in Beatrice, Neb

Plant manager: Chris Cerveny

Key project participants:
- Chris Backer, plant operator
- Dave Keim, plant mechanic
- Dave Ruskamp, O&M supervisor

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Challenge. During the winter months, snow accumulation inside the GT inlet filter house created a hazardous environment for plant personnel. The area is accessed when frost buildup occurs on the inlet screens located inside the weather hoods; frost must be removed to prevent turbine trips on high inlet differential pressure. The method of removal is to enter the filter house and brush the screens with a broom. This allows the frost to drop off the screen and fall down to the ground.

The problem is that after a heavy snowfall while the unit is online, and from the puffing action of the inlet filter cleaning system, there would be a 4-5 ft snow drift inside the filter house. Drifting was facilitated by the as-designed steel-plate floor, leaving two options for accessing the area: (1) Climb over/through the snow drift or (2) shovel the snow out of the compartment.

Solution. One of the plant operators offered what appeared to be a simple and effective solution: Replace the plate-steel flooring with steel-deck grating. The openings in the grating should be sufficient to allow the snow to fall out of the inlet house without any significant accumulation. The next step involved contacting the gas turbine OEM and performing an engineering evaluation.

The response to the evaluation was favorable in that they stated there would be no reason why we could not replace the solid floor with steel-deck grating. We happened to have enough grating left over from plant construction, so the cost of implementing this design change consisted only of having a scaffold built to access the bottom side of the inlet filter house in order to remove the original steel-plate flooring (Fig 39).

Results. It is no longer necessary to shovel snow out of the inlet filter house during the winter months, and more importantly, it will not be necessary for plant personnel to climb over the snow drifts. What little accumulation there may be can easily be swept down through the steel-grating floor. This eliminates the need for plant personnel to spend any more time than necessary inside the inlet filter house which becomes quite cold when the outside air temperature is in the single digits and the unit is online.

Meteorological data produces heat-stress caution and warning alarm

Arlington Valley Energy Facility

Owned by LS Power Group
Operated by NAES Corp

Challenge. The desert environment that our plant is situated in is well known for being a hot and inhospitable place during the summer months. Temperatures soar into the 110F to 120F range for months on end. The nighttime temperatures offer little relief. When the monsoon rains start in mid-summer, temperatures drop slightly but the humidity levels climb concurrently.

Heat exhaustion, heat stress, and heat stroke can strike very quickly during the summer heat of the day. With such wide swings in temperature and humidity it is particularly important to take these in to account when considering heat exposure concerns.

Solution. Several key meteorological measurements for determining heat stress were already being measured at our plant—such as dry bulb temperature and relative humidity. The idea was presented that we could use these inputs to create cautions and warnings on the hottest days of the year in order to increase heat-stress awareness.

An alarm was programmed in the plant's DCS using a generally

Arlington Valley Energy Facility

570-MW, gas-fired, 2 × 1 combined cycle located in Arlington, Ariz

Plant manager: Greg Nugent

Key project participants:
Greg Heard, EH&S manager
Ron Sager, production manager
William "Jon" McCall (deceased), O&M technician
Arlington Valley O&M staff

accepted heat index formula. When these heat-stress caution and warning alarms trigger, the CRO makes an announcement to all personnel onsite of the heat-stress alert level and reminds everyone to take necessary precautions.

Results. The site has not encountered any heat-stress injuries or first-aid events since implementation. Some employees choose to employ ice vests and hydration backpacks or avoid staying outside for extended periods after a caution or alarm.

Hazardous gas detection system

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Armstrong Energy

International Power America Inc

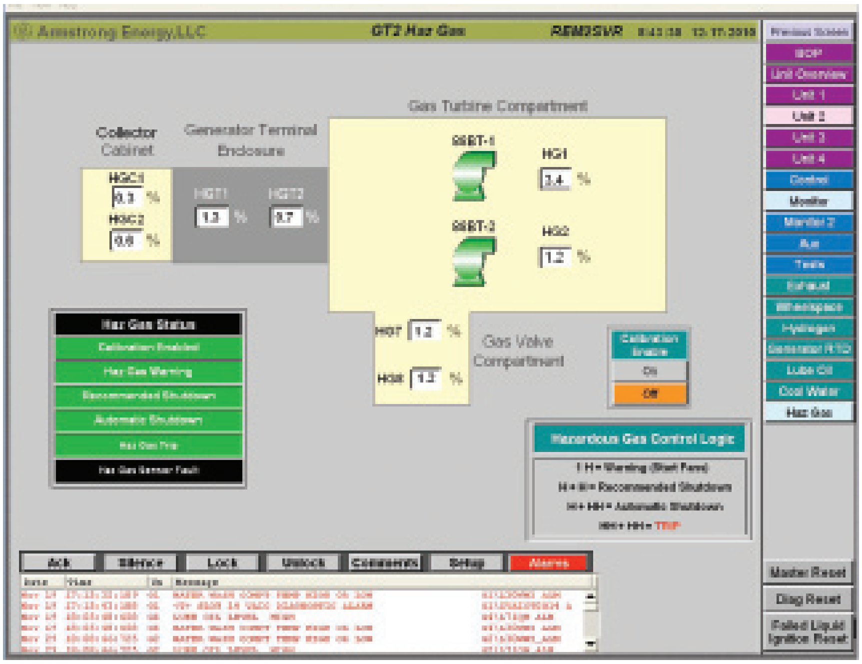
Challenge. Armstrong Energy is a four-unit, GE 7FA simple-cycle facility. As part of the original installation, hazardous gas detection sensors were located in the turbine and gas-valve compartments. During a TIL upgrade, additional sensors were installed in the collector cabinet and generator terminal enclosure (GTE).

All eight sensors installed were connected to two General Monitor four-channel combustible gas monitors and wired into the Speedtronic Mark VI controls as alarms only. A single composite alarm was issued for any of the four sensors connected to the CGM via a set of contacts located within the CGM itself with no remote monitoring available.

To compound the danger, the sensors were grouped together for the turbine, the gas valve, collector, and GTE so that if the CGM malfunctioned, no alarm or indication would be available for the affected compartment.

Solution. In order to correct this and provide the operator the ability to constantly monitor the combustible gas levels inside each affected area, the analog signals which were originally omitted from the configuration were used.

These analog signals were connected to the Mark VI analog inputs within the same enclosure as the CGMs and terminated in such a way as to provide redundant indication



Armstrong Energy

625-MW, dual-fuel, simple-cycle peaking facility located in Shelocta, Pa

Plant manager: Matthew Denver

Key project participants:
Wes Crawford, Jim Mandella, Peter Margliotti, Bryan Miller, and Dexter Cox, plant combustion turbine specialists

and protection for each compartment and prevent the complete loss of protection because of the malfunction of one CGM.

Logic was created to alert the operator if combustible gases were present in a specific location so appropriate action can be initiated. Additionally, after consultation with our corporate engineering department, a matrix of automatic logic controls was developed and implemented (Fig 40). This provided increased personnel and equipment protection.

Results. While the OEM upgrade could be viewed as expensive and complicated, with just a few materials, some locally developed logic, and a few man-hours, Armstrong Energy was able to develop an adequate detection and protection system. This system also provides the operator with real-time monitoring and display via a new screen. The increased ability to accurately detect and pinpoint areas of concern improve safety and reliability and system upgrade is being implemented throughout IPA's fleet of 7FAs.

Improved ladder cages reduce fall risk

Armstrong Energy

International Power America Inc

Challenge. We have a small but safety-oriented workforce that takes pride in maintaining an excellent safety program. One of the most important parts of establishing and maintaining a safe workplace is the ability to improve areas that have the possibility of causing a hazard to personnel.

A fatal accident at another plant brought on the realization that Armstrong could be improved to avoid a similar incident and better protect our staff from fall hazards. While descending a fixed ladder an individual lost three-point contact and fell backwards onto an unprotected section of the ladder. The handrail was too close to the ladder and as he was falling backwards he pivoted over the handrail and fell 30 ft to the ground and died.

An investigation showed that the fatality could have been avoided if a barrier had been installed between the lowest ladder loop and the highest barrier handrail to eliminate or minimize the possibility of a fall from a more elevated position.

Solution. A site inspection determined that the possibility of injury existed with the fixed ladders installed at our plant. The landing area of 16 ladders (four per turbine) and the handrail was relatively close to the opening of the ladder cage and imposed a fall hazard.

Results. With the help of an outside contractor, we installed ladder-cage extensions to act as a barrier between the ladder cage and handrail (Figs 41-44). While this does not eliminate the risk completely, it significantly reduces the risk to the individual and may even save a life.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Ergonomic improvements in an industrial setting

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

Tenaska Virginia Generating Station

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

Plant manager: Robert Mayfield

Key project participant:
Sam Graham, maintenance manager

Challenge. In preparation for the OSHA Voluntary Protection Program (VPP) review, the facility needed to better address ergonomics as part of their job hazard analysis (JHA). Ergonomics is an often overlooked hazard in the workplace.

The definition of ergonomics is basically the study of work and how it is to be done properly. It is the science of how human body works and the equipment design that maximizes productivity so people can be utilized to their highest potential. In other words, it is the study of how things are done in the workplace and the measures to be taken so a worker can be


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comfortable and at the same time be able to produce at the highest level.

Solution. The success of this program starts with training personnel to perform hazard assessments, empowering them to identify and correct deficiencies, clearly explaining the purpose of policies, and not just stating them for employees to memorize and follow. Keeping with this philosophy we formed a small team to devise an ergonomic program that followed the method of our safety culture. The original concern was that ergonomics would focus only on the best way to sit in a chair or hold a mouse.

An occupational therapist provided ergonomics training and workplace assessments. The trained nurse walked around the facility with the ergonomic program team and evaluated routine tasks employees performed.

Discussions were held on proper posture while at a computer, proper table height, working on concrete floors, heavy lifting, and repetitive tasks (Figs 45, 46). Non-routine tasks—such as crawling in HRSGs to perform inspections and repairs, working in turbine compartments, and elevated work during outages—are contributors to ergonomic injuries at industrial sites.

The team found other informational items from safety companies that provided guidance on ergonomic programs in industrial facilities. Members of the safety committee also attended VPPA conferences and conferences on ergonomics, which were particularly helpful in the design of our program.

Results. The facility was able to implement a plan that incorporated ergonomics into our everyday safety culture. An ergonomics plan was established which provided guidelines for routine and non-routine work that exposed employees to ergonomic hazards by adding ergonomics JHA, an ergonomic review on our work permits, and a method for employees to recommend improvements to the safety committee.

An ergonomics review is conducted quarterly by the safety committee and the plant controller. The occupational therapist provides training to all employees and is now incorporated into our annual training plan. Our ergonomics program helps provide protection from ergonomic injuries and is incorporated into our overall safety culture.

Granite Ridge Energy

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

Plant manager: William Vogel

Key project participant:
Susan Prior

Signage vital for emergency responders

Granite Ridge Energy

Owned by Granite Ridge Energy LLC
Operated by NAES Corp

Challenge. Granite Ridge Energy has multiple buildings on site, some of which have multiple work elevations where equipment is located and employees may be working at any given time. The challenge was to minimize to the greatest extent practical, the response time for off-

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site emergency response personnel by providing clear instructions as to exact location of the potential issue in the plant, whether it be an equipment fire or a man down.

This was a particular challenge on the off-shift when there are only three employees in the plant, including the CRO. If a person was injured and a second assisted, there would not be anyone available to escort the emergency responders to the correct location, and this could significantly increase the response time.

Solution. Working with the local fire department, Granite Ridge installed 18 × 18 in. highly visible numbered signs at all key entrances to buildings at the facility (Figs 47, 48). The sign numbers were included on a facility map which was provided to the local fire department and included in the site's emergency action plan.

Results. When seconds can make the difference between life and death, the installation of the door signage has enhanced the emergency response planning at Granite Ridge. When contacting local emergency services, the CRO now can give the responders the number which corresponds to the closest door of the emergency which will eliminate confusion and reduce the response time if an escort is not available.

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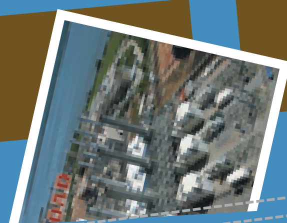

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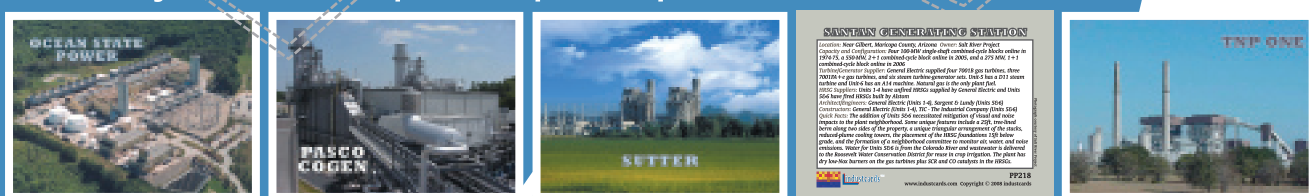

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Developing procedures for the purging, handling of natural gas

Natural Gas Plant Fleet

American Electric Power

Challenge. The fatal explosion during a gas blow at the Kleen Energy powerplant construction site in Connecticut on February 7, 2010, was the latest and most catastrophic in a series of similar events in recent years—including the ConAgra Slim Jim plant in North Carolina and Hilton Hotel construction site in San Diego.

Several months before the Kleen Energy explosion, the US Chemical Safety and Hazard Investigation Board (CSB) issued a safety bulletin entitled, "Dangers of Purging Gas Piping into Buildings," and three days before the Kleen Energy explosion, the CSB approved urgent safety recommendations to the National Fire Protection Assn (NFPA), American Gas Assn (AGA), and International Code Council (ICC) to strengthen the national fuel gas code provisions on purging.

Our group of affiliated companies, with a fleet of 23 gas-fueled powerplants and four coal-fired plants that use gas-fired boilers, plus others under construction or likely to be constructed in the near future, needed to ensure that its gas facilities were not susceptible to similar events. These companies could wait for the regulators and standard-making bodies to issue new rules or it could take interim measures to ensure it was providing the highest level of personnel safety during the handling and use of natural gas fuel.

Solution. In February 2010, the companies began the process that led to the creation of the Natural Gas Fuel Facilities and Operations Review Team. This multi-disciplinary team of generation and safety and health professionals was charged to proactively evaluate the safety of the companies' internal requirements, practices, and physical plant designs associated with the use of natural gas fuel for venting, purging, blowing down, and line-charging activities at its powerplants and make recommendations for improvement.

The scope of the review was fourfold:

1. Review and evaluate existing internal requirements and practices that address the following aspects of the handling and use of natural gas fuel at its facilities:
   - Design, construction, and modifications of facilities, equipment, and processes.
   - Startup, operation, inspection, and maintenance of facilities and equipment.
   - Training, qualification, and oversight of personnel involved in any of the above.
   - Management-of-change procedures involving any of the above.
2. Review and evaluate requirements and practices for protecting company personnel during gas handling and use activities performed by others at or in proximity to its power generation facilities.
3. Review and evaluate the designs, arrangements, and physical conditions of its power generation facilities that handle and use natural gas.
4. Research alternative practices, methods, or designs that would constitute "best practices."

Results. The team began work in early March 2010 and worked throughout the spring and summer. This included discussions with personnel responsible for gas purging and handling in other utilities and industries and gas transmission companies, plus an independent combustion engineering consultant with particular expertise is natural gas. The team also inspected a sampling of the gas plants within its fleet.

On Aug 31, 2010, the team delivered its draft findings and recommendations to its executive sponsors. The sponsors fully endorsed the report, which was organized along six focus areas:

- Design.
- Construction/startup.
- Operations.
- Training.
- Management of change.
- Benchmarking.

The sponsors also authorized moving forward with certain recommendations immediately and directed the team to continue its ongoing efforts in other areas. The team subsequently inspected additional plants in order to develop draft checklists for conducting thorough gas-focused inspections of all of its facilities.

The team presented an update to the sponsors on Dec 20, 2010, and followed-up with a short list of high-priority issues in need of attention, whether plant-specific or fleet-wide. The process of wrapping up the team's work and handing-off responsibility for inspecting the entire fleet and implementing recommended improvements began at year's end. A formal project management approach will be used for this purpose.

AEP Natural Gas Plant Fleet

Twenty-three gas-fired plants with a total generating capacity exceeding 8000 MW

Key project participants:
Patrick C Myers, team leader
AEP's Natural Gas Fuel Facilities and Operations Review Team

To date the following solid results are in place or in progress:

- Replacing natural gas with inert gas or air in gas piping cleaning blows.
- Development of mandatory training modules for natural gas awareness, operation, and maintenance for plant employees and contractors.
- Templates prepared for uniform emergency action plans to be created for each plant to properly guide operations personnel in the event of a natural gas emergency.
- Gas supplier interface documents that will cover venting, purging, and charging activities by the gas supplier on or near the plant site.
- Plant inspection templates have been created to guide uniform inspection and evaluation of natural gas equipment and facilities.
- Venting and inerting step-by-step procedures with job hazard analyses have been developed for maintenance activities utilizing "pressure cycling inerting" and "gas plume analysis."

Best practice in action

Noteworthy is a success story that occurred last October and November. A gas supplier informed a plant of its intent to purge almost five miles of 20-in. pipe and vent it through a 6-in. blow-off valve in the supplier's meter station located on plant property. The plant, with the guidance of this team, asked the supplier to provide a written procedure and dispersion modeling or other means to define the areas that could be affected by the venting.

Of particular concern was whether a 345-kV bus nearby would have to be de-energized. The supplier was receptive but had never been asked to go to this level of planning, and its initial well-intentioned response was lacking in many areas. As an example, the supplier had no emergency response plan for the activity.

While the supplier was responding to the plant's request, the plant developed its own comprehensive set of precautions and protective measures. Among numerous other actions it required a joint pre-job safety discussion among all plant and supplier employees who would be at the site. The purge was completed according to plan, and the plant's "Fuel Gas Supply Piping Purge Procedure" has become the model for other plants in the fleet.

Revised 'close-call' program improves safety

Rathdrum Power Plant

Owned by Rathdrum Power LLC
Managed by Power Plant Management Services LLC
Operated by NAES Corp

Rathdrum Power Plant

275-MW, gas-fired, combined cycle located in Rathdrum, Idaho

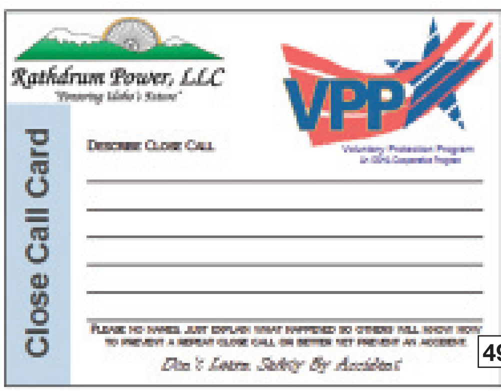
Plant manager: Gary Allard

Key project participants:
Dale Miller, compliance supervisor
Rusty Whiteley, division director
Alan Bull, project manager
Entire Rathdrum staff

Challenge. Rathdrum Power Plant is an OSHA VPP site that experiences very few accidents. Even still, near-miss events were not always being reported. Only one near-miss event was reported in 2008, none in 2009.

The near miss event that occurred in 2008 happened while plant staff was lifting a turbine coupling guard with a crane. The rigging caught on a fire protection pipe that was mounted directly over the coupling, and then the mounting bracket clamp holding the pipe pulled free and the pipe broke. The clamp that pulled free struck an employee on the chest, hard hat, and safety glasses. The employee's shirt pocket was torn and the employee received a small abrasion on the face. Luckily, no medical attention was required.

This was a potentially very serious accident, and the near miss was recorded. The near-miss program that was in place during 2008 and 2009 was a complex electronic reporting system that discouraged the input



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of less serious events and issues. The purpose of any near-miss program is to prevent accidents and other recordable incidents.

Solution. To improve near-miss reporting, compliance supervisor Dale Miller revised the near-miss program in 2010 to encourage safer working conditions at the plant. As pointed out by a former OSHA VPP inspector, near-miss events can be successfully used to measure unsafe conditions at the plant and to make improvements.

First, the electronic near-miss program was replaced with a manual, anonymous close-call program. This way, plant staff can report anything that appears to be of concern simply by filling out a 'close-call card' (Fig 49), and anonymously placing it in the nearest 'close-call box' (Fig 50).

The card openly states: "Please no names, just explain what happened so others will know how to prevent a repeat close call or better yet prevent an accident." There isn't even any requirement to be an actual near miss. The plant safety motto is also printed on each card: "Don't Learn Safety by Accident."

Second, a graphic "near miss" photograph or illustration was placed above each close-call box to encourage the use of the close-call cards and program. The close-call boxes are located throughout the plant for easy access.

Third, Miller collects the cards and the plant safety committee reviews each one to determine if the report is indeed a near miss. For each near miss, the committee then submits a near-miss report and takes the necessary action to mitigate the near-miss potential. This may require training, hiring a vendor to provide onsite inspections and corrections, or simply a reminder at a regularly scheduled safety meeting.

Results. During 2010, a vast improvement in the program was noticed; 11 close calls were reported. Every close call was investigated, and appropriate action was taken in each case. Not only has plant safety improved, but employees have enthusiastically embraced the revised program because of its ease of use and anonymity. Here are some examples of near misses and actions taken at Rathdrum:

- An employee caught a foot on the stairs and fell forward onto his hands, but sustained no injuries. This was used as a safety awareness topic.
- While sliding a heavy box across the floor with a toe, the employee felt stress in the back and stopped, realizing how close they had come to an injury. This topic was used at a safety meeting wherein an expert doctor on back injuries was invited onsite to train employees on back safety and proper lifting techniques.
- An employee observed what he thought were protruding steel deck grading joints, presenting potential fall hazards. After an investigation, it was determined to be a normal condition that presented no real trip hazard.
- When opening a cabinet to take readings from gages located in the cabinet, an employee almost slammed the door on his hand. This was discussed, and it was determined that no real solution was required. Employee safety awareness and care was stressed.
- A delivery truck making a U-turn on the plant site struck a garbage dumpster, moving a Jersey wall 12 in. This near miss was reviewed by plant personnel, and it was agreed that plant staff must provide a spotter for trucks while they maneuver onsite.
- An employee noticed a dripping valve on a chemical delivery truck during a transfer of aqueous ammonia. The delivery was shut down, and the valve was examined. It was discovered that the valve was improperly assembled and could have easily blown out causing a reportable issue. Fortunately, the quick call by the employee prevented this from happening.
- An employee pushed a button to open a large roll-up door, and a wire from the safety strip located at the bottom of the door struck him in the face. The employee was not injured. Later it was discovered that the wire was energized. All door strips were inspected and replaced with a pneumatic system.
- During a "permit-required confined space entry," the door watch noticed small spikes of carbon monoxide on the meter, and reported it. The job was shut down, and staff discovered that gas-fired welding machines located nearby were the source of the CO. The welding machines were relocated, and the CO problem was resolved.
- An employee observed a subcontractor building a block wall onsite without proper footwear. The job was shut down, and it was discovered that the subcontractor had not received orientation to the plant safety programs.

'Arc flash' NFPA 70E site implementation

Selkirk Cogen

Owned by Selkirk Cogen Partners LP
Operated by GE Contractual Services

Challenge. Plant personnel conducted their first arc flash study in 2001 when data were collected for breakers, relays, and transformers from around the site. On the basis of that initial study, the required PPE was

ARC Flash "PPE" Protective Clothing Requirements

Cal/cm²	Min PPE	Clothing Description
0-2	#0	8 Cal/cm² uniform, Safety glasses, hard hat.
>2 - 4	#1	8 Cal/cm² uniform, arc-rated face shield, Safety glasses, hard hat, properly rated voltage-rated gloves.
>4 - 8	#2	8 Cal/cm² uniform, arc-rated face shield, Safety glasses, hard hat, properly rated voltage-rated gloves.
>8 - 25	#3	25 Cal/cm² arc flash suit, 8 Cal/cm² uniform, arc-rated face shield, Safety glasses, hard hat, properly rated voltage-rated gloves. See NOTE 1.
>25 - 40	#4	40 Cal/cm² arc flash suit, 8 Cal/cm² uniform, arc-rated face shield, Safety glasses, hard hat, properly rated voltage-rated gloves. See NOTE 1.
>40	X	"EXTREME DANGER" Dangerous work hazard; Energized work prohibited. See Maintenance Supervisor for direction.

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NOTE 1: SCP's interpretation of NFPA 70 2009 Table 130.7 (C)(11) is that the sum of layered PPE arc flash ratings needs to be greater than the arc flash hazard listed on the equipment arc flash warning label(s).

Selkirk Cogen

345-MW, gas-fired, combined-cycle cogeneration facility with two power blocks. Phase 1: 80-MW 1 × 1 combined cycle. Phase 2: 265-MW 2 x 1 combined cycle

Plant manager: Brian Connolly

Key project participants:
- Bob Keute, maintenance supervisor
- Bill Slaver, controls and reliability specialist
- Phil Muller, I/E technician
- Tom Nolan, operations supervisor

purchased and equipment labeled as recommended.

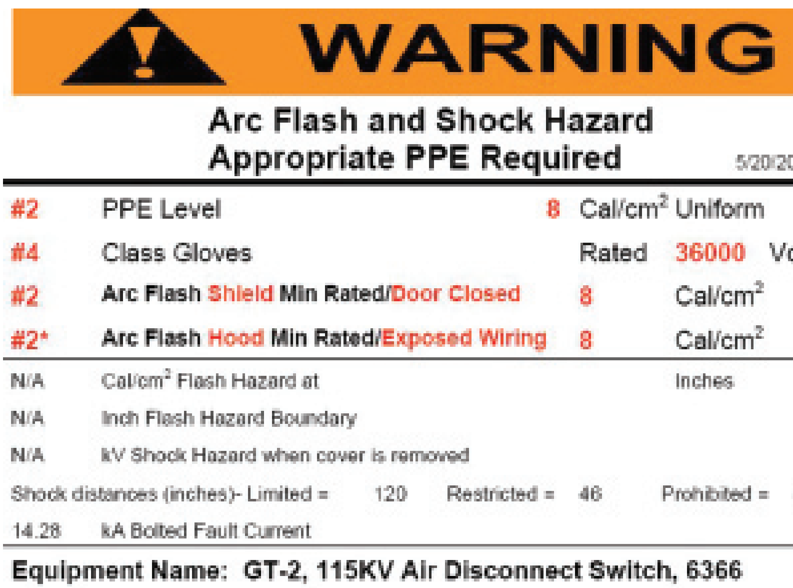
In 2009, NFPA issued an updated version of NFPA 70E with a requirement that either the calculated incident energy or the level of PPE must be listed on the arc-flash warning labels. Plant personnel decided it was necessary to update our current arc-flash program to meet these new requirements.

Solution. The site maintenance team redesigned the arc-flash warning labels for all the electrical equipment 120 V and above for the entire site. All labels clearly listed the PPE requirements for the different potential incident energy levels (Figs 51 and 52).

The team also had the electrical one lines for the site redrawn with color-coded separation that identify minimum PPE requirements for a particular system (Fig 53). The site also installed several arc-flash reduction modules to reduce the flash potential on certain pieces of equipment.

Results. O&M personnel participate in annual high-voltage refresher training which brings about improved communication between the operations and maintenance teams when any high-voltage work is being performed. Increased effort in job planning and in-depth pre-job briefings has improved the overall safety mindset onsite.

With the implementation of this best practice by the maintenance team, all employees are now aware of the safety concerns around high-voltage work because of our site's deeply engrained safety culture. Our site has a first-class safety record and efforts like this continue to keep it that way.



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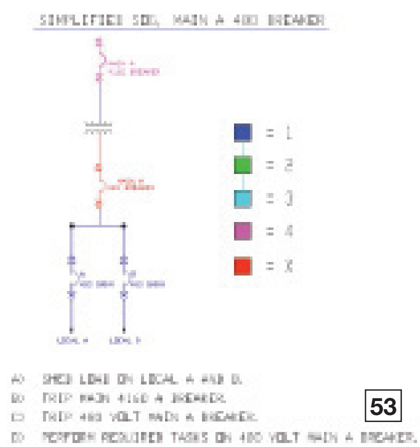
Database creates a safer confined-space program

Hopewell Cogeneration Facility

GDF Suez Energy North America

Challenge. Confined spaces are some of the most dangerous places in which to work. Since they are not a normally manned space, they have many more hazards than the typical work area. When working in these spaces the idea is to reduce the risk as much as possible.



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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
Jeff Villines, Chris Fegley, Ken Blalock, Enrique Toro, David Taylor, Jeff Husie, Evan McCoy, Andrew Kirby, Rudy Ashley, and Jamie Dalton, plant operators

There will always be some safety risk, but the more hazards that can be reduced, the better chance that someone will not get hurt. Risk mitigation priorities include making sure the paperwork matches the space, conducting an in-depth assessment, and storing the information for quick access.

The plant believes the risk will be significantly reduced by being sure of the space being entered, having the paperwork written and checked in advance, having calculations worked out in advance, and by being sure that in the event of an accident there is a plan that has already been worked out.

Solution. The plant has implemented ideas to reduce safety risk within confined spaces. Using Microsoft Access® to build a database with all confined spaces, each area was evaluated for existing hazards before entry and once inside the space (Fig 54). One problem that comes up is that plant personnel and contractors do not call a space by the same name. To eliminate this, the database has pictures of the confined space so that the workers know for sure what space they are going into (Fig 55).

When a picture or block with the name in it is clicked it will bring up all

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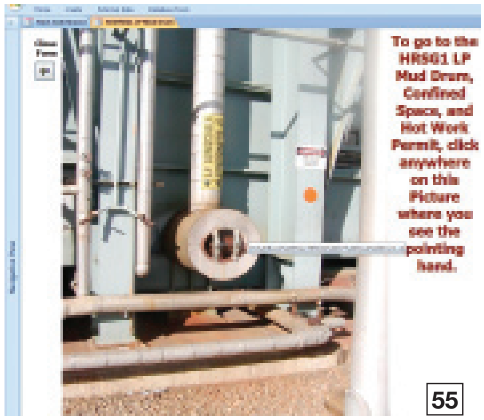

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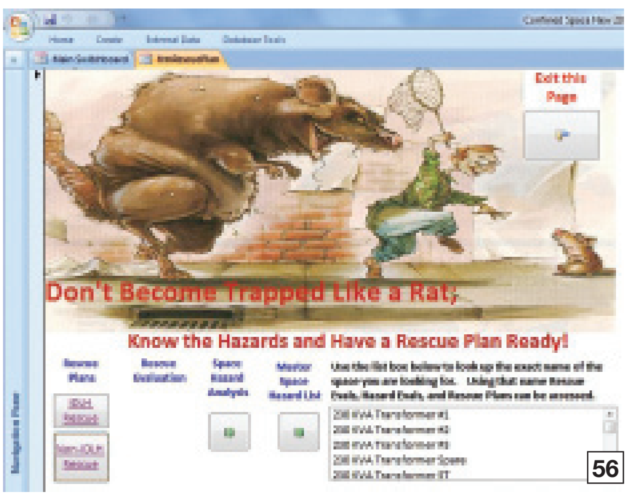

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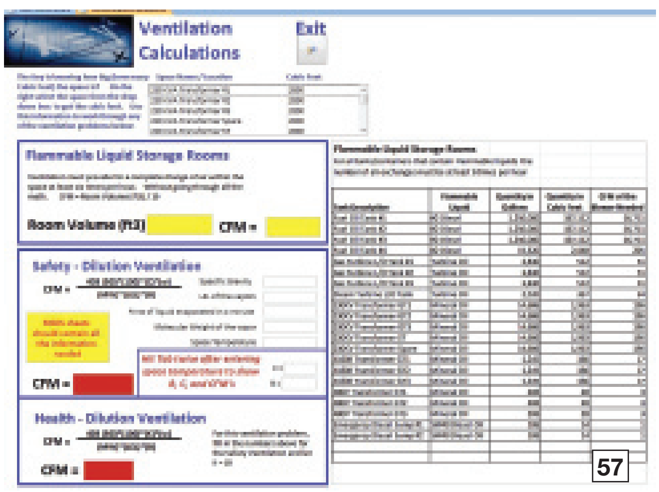

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the paperwork needed in accordance with OSHA regulations, including hot-work permits. The paperwork is set up in Microsoft Excel® with links so that once the first page is filled in as to supervisor, date, work order number, LOTO number, and confined space number all the other sheets are filled in as well. The paperwork includes instructions for a confined space rescue (Fig 56).

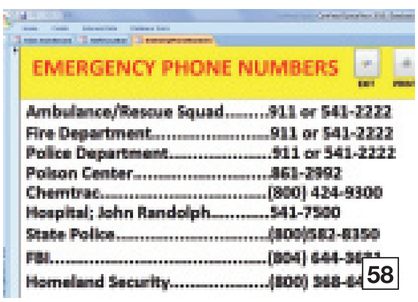
The plant had the rescue squad survey the plant and all of its confined spaces. The survey revealed the need to weld some pad-eyes and to acquire a special harness. The plant purchased the harnesses, links, and lines for plant personnel and the rescue team, so all parties would be adequately equipped.

Tanks brought onsite for temporary storage can be evaluated and placed into the database for future use. For spaces that are used for fuel, there are specific rules for ventilation. All of these spaces have been calculated in advance to be sure of compliance (Fig 57). For other spaces that may need ventilation subroutines have been setup so that one can look a space up, or use the program to get the ventilation flow. To protect from overheating there is a section for "dilution ventilation."

In case something does happen; emergency phone numbers are in placed in several areas in the control room. For extra safety, they are also listed in the database (Fig 58).

Results. It takes about 20-30 minutes to do a proper job on writing up a confined space from scratch. During our last maintenance outage, the first day saw 42 confined spaces written up. Uploading the report to the database takes less than two minutes each and can be input by the night shift and ready for the following morning.

By conducting rescue surveys and having calculations completed in advance, both plant personnel and the rescue personnel feel more confident and better prepared. It is programs like this that have taken the plant to more than 6000 days without a lost-time accident.



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Integrated fire and rescue training program

New Covert Generating Facility

Owned by New Covert Generating Company LLC
Operated by NAES Corp

New Covert Generating Facility

1100-MW, gas-fired, three G-class 1 × 1 combined cycles located in Covert, Mich

Plant manager: Rich Evans

Key project participants:
The entire New Covert team
Covert Township Fire Department

Challenge. Powerplants across the country are challenged to use cost-effective solutions to address potential real-time fire and rescue emergencies. The template outlined in this best practice illustrates the practical approach used by our plant to get predictable results if/when the unexpected fire and/or rescue condition occurs.

Solution. The plant's fire and rescue training plan is based on the assumption that there is a reasonable probability that an actual fire or rescue emergency will occur. In preparation for such an emergency, the Covert team has learned that it is extremely important to collaborate with all stakeholders including asset owners, training vendors, and community local fire


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and rescue teams to jointly develop the best executable plan for the most probable emergency situations.

The Covert team uses the continuous-process-improvement approach structured on the APIE model (Fig 59):

- Assess: decide what needs to be done.
- Plan: jointly develop a plan with stakeholders.
- Implement: drill to validate plan.
- Evaluate: integrate lessons-learned.

Results. Confined-space and rescue training is provided onsite annually to both employees and local fire and rescue organizations as part of the annual safety training program requirement.

The confined-space and rescue portion includes one segment specifically for the local fire and rescue organizations (Fig 60). The plant hosts the training onsite which includes rescue drills (Figs 61-63). The onsite training allows potential emergency responders to learn the geography of the plant and to help visualize and practice the most probable rescue scenarios. The onsite training also allows local rescuers a chance to get to know the people in the plant (Fig 64).

The rescue training coupled with an emergency fire drill combine for a comprehensive fire and rescue plan. The drill is critiqued by all stakeholders and lessons learned are incorporated into the next training and drill exercises (Fig 65).

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In-house infrared surveys allow more timely, effective assessments

MEAG Wansley Unit 9

Owned by Municipal Electric Authority of Georgia
Operated by GE Contractual Services

Challenge. Annual preventive maintenance activities to perform infrared surveys on high voltage electrical busses (4160 V) and equipment have inherent safety issues that include accidental contact with live electrical components and possible exposure to an arc flash.

The infrared surveys require the opening of cubicle doors on HV electrical control centers. The opening of these cubicle doors would have to be scheduled during planned outages

MEAG Wansley Unit 9

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

Plant manager: Keith Feemster

Key project participants:
Ken Burton, maintenance technician
Tim Williams, maintenance manager

when electrical loading was not typical. A contractor would have to be scheduled for these tasks and was generally unfamiliar with the site's equipment and procedures.

Solution. As a part of the site's continuous improvement culture, personnel are encouraged to recommend areas where safety and quality can be improved. As the result of a recommendation to perform the infrared surveys in-house, the site purchased an infrared camera along with software needed for completion of the surveys.

The site also purchased and installed infrared viewports on the HV electrical cubicles and equipment to allow safe inspection of these areas. Site technicians completed a Level 1 infrared certification course which enables them to operate the camera and evaluate the captured infrared images.

Materials and training needed for implementation are:

- Infrared Camera and software, $17,995.
- Spyglass lens for camera, $5,650.
- Viewports (arc flash protection level), $150 each.
- Level 1 certification course, $1,800.

Results. Infrared surveys now are conducted at any time without the delay or cost of hiring a contractor or scheduling equipment outages. The installed viewports allow surveys to be conducted without the opening of electrical doors. This eliminated the potential for arc flash along with exposure to live electrical components.

The camera can be used on multitude of equipment. In addition to identifying poor electrical connections and devices, we have been able to identify hotspots on our HRSGs, piping insulation breakdown, and loose mechanical components. Since our site technicians, who have an inherent knowledge of the equipment are conducting the assessment, we can better identify both maintenance actions and priorities.

Performing a hazard-free, environmentally compliant outage

Walter M Higgins Generating Station

NV Energy

Walter M Higgins Generating Station

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

Plant regional director:
Steve Page

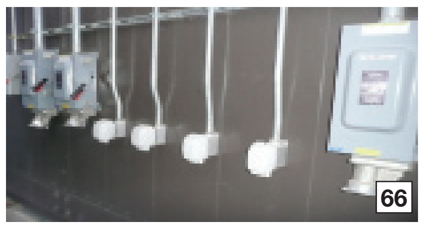
Key project participants:
Kevin Newcomb, maintenance manager
Lloyd "Andy" Anderson, maintenance manager
Felix Fuentes, operations manager

Challenge. During major maintenance outages, the sheer volume of heavy work and number of personnel in confined areas makes detailed planning and continuous monitoring all of work critical to ensuring no injuries and environmental incidents occur. Preplanning for any outage is crucial and safety and environmental compliance must be an integral part of outage preparation.

Winter 2010 saw a large amount of work scheduled: two full generator rewinds, major valve work, HGP inspections, as well as numerous other maintenance activities. All of this work required a large number of personnel in a very crowded area.

Solution. Long before an outage begins, the team makes detailed site plans—including laydown areas for major pieces of equipment, location of construction trailers and restroom facilities, etc. Spill kits, safety supplies, firefighting equipment, evacuation routes, and assembly locations are also included. Contractor orientation includes a detailed description of all locations to ensure everyone onsite understands where needed supplies and facilities can be found.

Preplanning also identified several methods for reducing the likelihood of an injury occurring. Some of this work included relocating a cable tray to ensure easier access for elevated equipment, installation of pull routes for air hoses, extension cords, etc (which eliminates tripping



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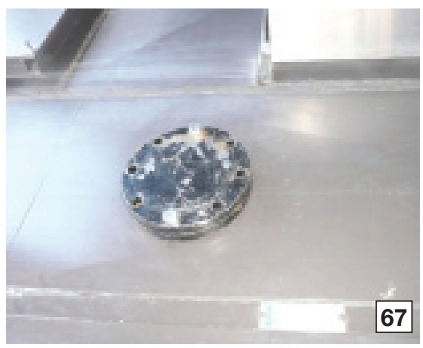

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hazards on walking surfaces), installation of additional outlets and welding stations, prestaging of spill kits, drums for used oil and oily debris (on containments), etc (Figs 66-69). Several areas of the plant were also paved to provide better working surfaces and routes throughout the site.

One person is dedicated to serve as a safety advisor on every shift during an outage. This trained expert has no other role to fulfill other than to serve as a safety observer, assist in permitting, and provide any expertise or equipment needed to ensure a safe workplace is maintained.

Through a collaborative working relationship, the safety advisor attends every shift safety meeting and maintains a running log of activities. The safety advisor's presence alone ensures all contract labor has safety first and foremost in mind during any evolution.

Daily environmental rounds are also completed by a designated employee. This task ensures no oil spills, necessary equipment is readily available, waste drums in satellite locations are maintained, and all chemicals used during the maintenance are properly labeled, contained, and disposed (Fig 70).

MSDSs for all substances to be brought on site are collected before the outage begins. These MSDSs are gathered and a book developed to ensure all employees and contractors have access to the needed information concerning all substances in the workplace.

Daily safety meetings begin every shift. These brief safety talks include relevant subject matter as well as a timely review of any incident which may have occurred the shift before. These incidents include accidents, injuries, near-misses, etc.

Results. A collaborative working relationship with contractors, and preplanning and continual monitoring of safety and environmental compliance, help ensure a safe and efficient outage. Comprehensive outage safety procedures from the preplanning stages through major maintenance highlight the site's attention to detail for personnel safety and environmental compliance.

During the major maintenance outage in the winter of 2010, involving 309 contract employees, 14 near misses occurred and were properly documented. Two injuries occurred, neither of which resulted in lost time. Zero environmental incidents resulted from this work.


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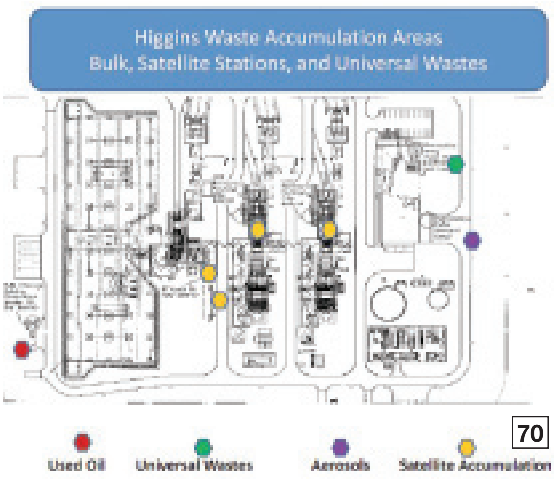

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Natural-gas handling procedures

Walter M Higgins Generating Station

NV Energy

Challenge. In light of several tragic and high-profile accidents involving handling of natural gas, our personnel began a concentrated effort to ensure a similar incident does not occur at the company's facilities. Natural gas handling is a routine evolution at many powerplants: gas blows, flow checks, purging, and other O&M functions involve the handling of highly explosive natural gas and hydrogen.

Many employees take these evolutions for granted. Recent, large-scale accidents resulted in terrible loss of life, injuries, and equipment damage. Developing formal procedures and training of employees can eliminate the potential for more explosions.

Solution. O&M personnel developed formal gas handling policies. These procedures ensure a safety standdown before proceeding with any venting or purging operations. All affected personnel gather for a formal safety meeting before proceeding.

This meeting includes a review of the hazards associated with the gas involved, a review of the appropriate prints and P&IDs, and detailed discussion. To proceed, acknowledged understanding of each person's role in the evolution and a Q&A session ensures everyone understanding.

All non-essential personnel are then removed from the affected area. Smoking and all hot work is secured throughout the plant, access to the plant is secured, and a walk down of the affected systems and adjacent areas takes place.

Once these conditions are met, the CRO communicates this fact via the plant PA system. A checklist is followed to ensure no step is overlooked. The CRO then coordinates and gives the go ahead to proceed with the evolution. Upon completion of the gas venting or purging evolution the CRO announces the completion of the work and normal operations and work resume.

Results. A formal natural gas and hydrogen handling policy, formal procedures, and employee training are critical to ensure no more disasters occur in our industry. Since implementation, no accidents related to gas handling have occurred at Higgins.

Borescope safety, practices

Armstrong Energy

International Power America Inc

Challenge. Armstrong Energy performs an annual borescope inspection on each of the four 7FA gas turbines onsite. The task of prepping a unit for inspection can be very tedious, especially if the job is not planned well and preventive maintenance actions are not taken to ensure the unit can be opened without any mishaps.

Before the job can be started a LOTO has to be performed to ensure the safety of personnel and equipment. During this process, the inlet guide vanes (IGV) are opened, the actuator arm pin pulled, and a safety block put in place to prevent the vanes from accidentally closing. A few processes were developed to accomplish this task in a safe manner.

Solution. A ladder attaches to the platform next to the IGVs to allow easy access to remove the pin (Fig 71). Secondly, an IGV block, made from a heavy duty bolt and a handle, is attached to the threads (Fig 72). This prevents personnel's hands from entering the path where the block is placed. Thirdly, a tool was made to force the IGV pin out of the dog bone eye without hammering out the pin and causing damage to the equipment (Fig 73). Once the IGVs are put into the correct angle, personnel can set the tool in position and remove the pin safely.

Ensuring the proper tools are present for the job is a key ingredient to a successful outage. This saves a lot of time and heartache. The best way to ensure this is to provide two pre-staged job boxes with all necessary tools needed for the job (Fig 74). One box is staged on the upper level, the other on the lower level of the unit receiving the borescope.

Each job box is equipped with two toolboxes which house the different size of sockets, wrenches, adapters,

Armstrong Energy

625-MW, dual-fuel, simple-cycle peaking facility located in Shelocta, Pa

Plant manager: Matthew Denver

Key project participants:
Wes Crawford, Jim Mandella, Peter Margliotti, Bryan Miller, and Dexter Cox, plant combustion turbine specialists

and extensions to remove the necessary bolts. In addition, there is an air impact gun, hose, and lifting chain to remove the manway covers located on the gas turbine engines (Fig 75).

Removal of the manway covers may appear to be an easy task but it's not always as easy as it looks. The top cover can be lifted off with the use of the overhead chain fall (Fig 76), but the bottom cover is a challenge in itself. To combat the problems with lowering the bottom manway cover the plant decided to make three guide rods which are threaded on each end (Fig 77). Utilizing three chain falls in coordination with the guide rods and the gas turbine eye bolts, the man way cover can be lowered easier and safer.

Bolt maintenance is an important key in this process. It ensures the bolts will be removed safely and without damage (Fig 78). Removal of bolts the first year was a horrendous task. A few bolts broke, damage occurred to threads and slugging wrenches had to be used when the pneumatic impact guns couldn't perform the job.

To prevent that from recurring a

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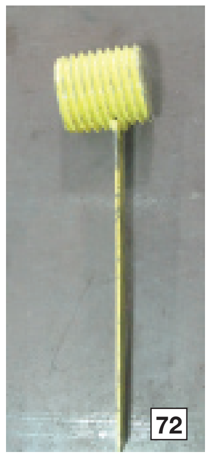

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maintenance program was implemented to have all bolts cleaned using a die, cutting oil, and a wire wheel buffer (Fig 79). The bolt holes are also tapped; thereby the bolts come out easier and without any damage.

During the evolution of opening the turbine for maintenance, a member of the management team observes and records findings on a "Fresh Eyes Observation Form" (Fig 80). This program allows another set of eyes to observe the task being performed, highlighting what was done wellt, what can be improved, and to ensure the overall safety of the job.

Results. When all these practices are put together, the resulting borescope preparation and inspection is a much safer and efficient task. With

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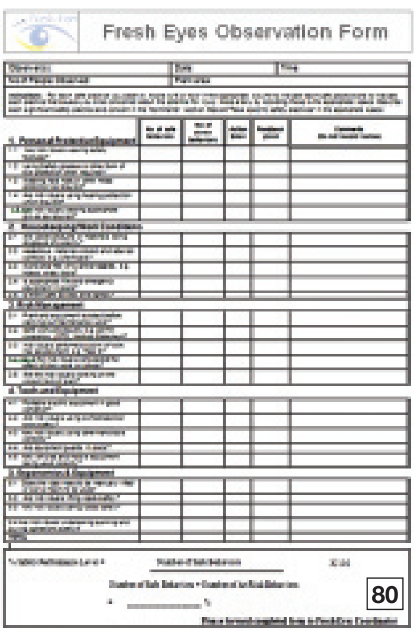

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plant staff pulling together, focusing on an assigned task, and constantly searching for safe and effective ways to improve the process, we feel this qualifies as a best practice.

LOTO system improvements

Blackhawk Station

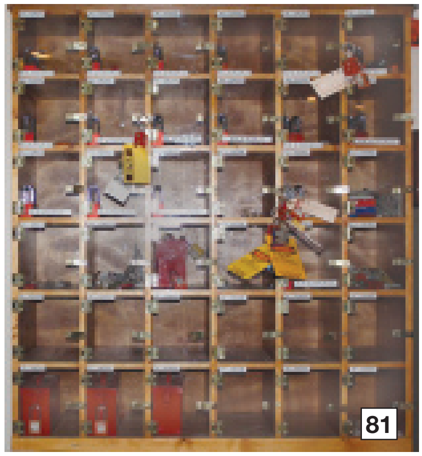
Owned by Borger Energy Associates LP
Operated by NAES Corp

Blackhawk Station

230-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Borger, Tex

Plant manager: Craig Courter

Key project participants:
- Steve Nelson, operations supervisor
- Bryan Stout, maintenance supervisor
- Alan Bull, project manager



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Challenge. Blackhawk Station's LOTO system was very time consuming and cumbersome. The system had very little congruency between shifts because the paperwork and tagging were performed manually. The system utilized lock boxes that were hard to keep maintained in an organized manner and created other issues with identifying which system was assigned to boxes during large scale outages.

Solution. Steve Nelson, operations supervisor, noticed immediately when he started at Blackhawk that an excessive amount of time and energy was being spent on the LOTO program. The LOTO system being used employed the use of the red lock boxes and a ring full of locks and keys (no locks keyed alike). The outside operator would take his ring of keys and fumble through each one for each lock in the field. The red lock boxes would be piled on a desk in the control room and were very cumbersome to work with.

Nelson redesigned the LOTO program to avoid the pitfalls associated with individual lock boxes. The cabinet he built kept all the lockboxes in one location (Fig 81). The lock out cabinet was equipped with lock sets from six locks to 20. The individual lock sets are keyed alike, eliminating the wasted time operators would spend trying to match keys to locks in the field. Next step was to automate the tagging system.

The legacy system at Blackhawk required every LOTO to be handwritten, which was tedious and time-consuming. Using the same format as the handwritten LOTO, he copied each LOTO from the LOTO history to an Excel® spreadsheet. The operator writing a LOTO now chooses the equipment to be locked out from a list, then inputs the data required on a cover page.

A "tag" page was then designed and formatted to pull data from the cover page. Once all the information is input into the cover page the operator can print to a printer dedicated to the LOTO program. The cover page will print first. Then the operator inserts a tag sheet and hits print again and the tags are printed on the tag sticker sheet. The tags can now be peeled off the sheet and attached to tags to be hung in the field.

Results. The system has proven effective not only in time saving but also in congruency of the LOTO program. Nelson works closely with the O&M staff to ensure that proper procedures are followed and all isolation is done in accordance with corporate procedures. The system locking procedures are identified and reviewed by several team members and then documented in the Excel® spreadsheet creating a valuable database for future use.

Celebrating two decades of service to electric-power producers

20th Annual Southwest Chemistry Workshop

Southwest Chemistry Workshop
2011 Conference and Exhibition

Hilton El Conquistador • Tucson, Ariz • June 7 – 9

Host utilities: Tucson Electric Power Co and Arizona Electric Power Co-op

The industry's most practical conference on water chemistry brings together powerplant chemists and O&M personnel to resolve issues associated with cooling-water, makeup, and condensate/feedwater treatment, and instrumentation.

Owner/operators of nuclear-, fossil-steam-, and gas-turbine-powered generating plants nationwide will be present in Tucson, as will the leading consultants, instrumentation manufacturers, and water treatment equipment and chemical suppliers. The collaborative environment fostered by the Southwest Chemistry Workshop enables attendees to grow professionally and return to their plants with ideas for reducing expenses and improving performance worth many times the cost of attendance.

Conference highlights:

- Golf tournament, Monday, June 6, 1 pm.
- Presenters' dinner, Monday, June 6, 6 pm.
- Technical presentations and open discussions all day Tuesday June 7 and Wednesday June 8 and the morning of Thursday June 9.
- Vendor fair open during all breaks, breakfasts, lunches all three days.
- Family night dinner and entertainment, Wednesday June 8, 6 pm.

Key contacts:

- Golf, Mike Bryan (mbryan@tep.com)
- Presentation idea, Kurt Bayburt (kbayburt@aepco.coop)
- Vendor fair, Kurt Bayburt (kbayburt@aepco.coop)
- Registration and other inquiries, Andrea Mitchell (amitchell@tep.com)

Fee schedule:

- Early bird registration (before March 1), $400
- Regular registration (March 1 and beyond), $450
- Booth fee, $500. Plus, every person participating in the vendor fair must register at the rate in effect on the registration date ($400 or $450)—no exceptions. Plus, plus, package receipt and storage charges (for up to seven calendar days prior to the event) are billed at $0.49 per pound and the shipper's responsibility
- Golf is $50
- Family night dinner, $20 per person; children 12 and under are free

IMPORTANT: www.southwestchemistryworkshop.org launches February 1, 2011

Program updates and details on how to register will be posted to this site, which will include presentations from the 2009 and 2010 meetings. You can access the 2009 presentations now at www.combinedcyclejournal.com/southwestchemistry.html.

Expansion joint failure mitigation

Wolf Hollow I

Owned by Stark Investments
Managed by Insight Energy LLC
Operated by NAES Corp

Challenge. Maintaining the integrity of expansion joints between the gas turbine and heat-recovery steam generator (HRSG) at plants powered by G-class engines has been an industry-wide challenge. Expansion-joint failures have adversely impacted the reliability, availability, and profitability of these plants—particularly those cycling daily.

In addition to the expense associated with availability loss, expansion joints—ranging in size from 15 to 23 ft in diameter—can cost thousands of dollars to repair and upwards of a million, or more, to replace (Fig 82). Actual repair and replacement costs depend on the nature of the failure, required work, and market conditions.

Some of the issues experienced at Wolf Hollow I, which averages over 200 start/stop cycles annually, include the following:

- Failure of metal mesh designed to retain the layers of insulation within the expansion joint.
- Failure and/or liberation of liner plates installed to cover the space on the exhaust-gas side of the joint between sections of exhaust ductwork. These failures result in insulation being pulled into the exhaust stream and fouling the SCR catalyst. Such fouling can limit unit output because of increased turbine backpressure and/or reduced catalyst performance; in the extreme, a unit trip is possible.
- Failure of the weld joining the exhaust duct and expansion-joint frame, resulting in leakage of hot gas which causes efficiency loss and may damage electrical conduit, wiring, and/or instrumentation. Personnel safety is another concern.
- Failure of the outer "belt" covering of the joint as a result of insulation loss within the expansion joint and/or compression/tension fatigue stresses, both allowing leakage of hot gas and contributing to the issues described in the previous bullet point.

Historically, the plant had operated only 60 to 90 days between repairs to one or more of its six expansion joints (three per unit). Repairs ranged from installing a "patch" on the outer belt to complete joint replacement. The financial impact to Wolf Hollow has been significant; repair/replacement costs have exceeded $5 million since first commercial operation in 2003.

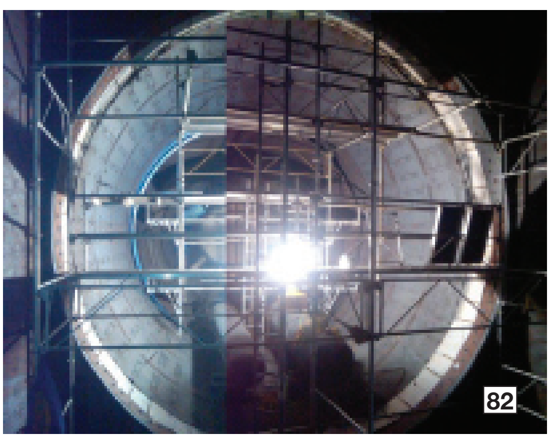
Solution. Wolf Hollow performed detailed failure analyses for its

Wolf Hollow I

730-MW, gas-fired, two-unit, 1 × 1 combined cycle located in Granbury, Tex

Plant manager: Kelly Fleetwood

Key project participants:
- Adam Jackson, plant engineer
- Shane Maples, maintenance supervisor
- Ryan Sachetti, project engineer, Industrial Air Flow Dynamics Inc



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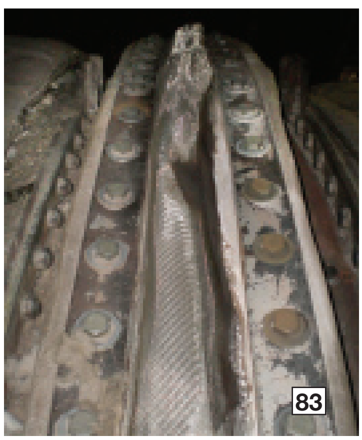

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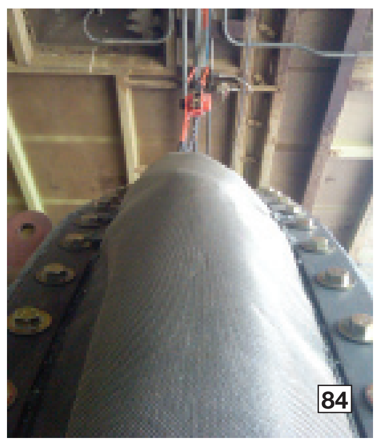

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expansion joints—including failure mechanisms, failure rates, collateral damage, repairs, and cost impact. The first expansion joint immediately downstream of the turbine case (EE00) was the worst in terms of repair frequency and cost, followed by the third joint (EE02) located between the transition from the cylindrical exhaust duct to the rectangular entrance to the HRSG. The second joint (EE01) had the most favorable frequency-of-repair record.

Review revealed EE00 was part of the turbine supplier's scope of supply and Wolf Hollow engaged the OEM to support a detailed evaluation of the failures, determine the causes of the failures, and recommend options to prevent failures in the future.

The plant also elected to partner with Industrial Air Flow Dynamics Inc, Glastonbury, Conn, to perform an independent analysis of each of the three expansion joints. This decision was based on IAFD's (1) commitment to gather actual operating data, (2) its willingness to conduct a comprehensive historical review of events at Wolf Hollow and other facilities IAFD had performed work for, (3) design capabilities, and (4) commitment to customer needs.

The failure mechanism for the EE00 joint was insufficient clearance (gap) between the faces of the expansion-joint frame (Fig 83). The clearance provided did not allow the outer belt to flex within design tolerances.

The clearance varies as the unit cycles because of the thermal growth/contraction of the exhaust duct. The stiffness of the outer belt is determined by design requirements and materials necessary to meet the operating conditions. When the outer belt is compressed or stretched beyond its material limits, the belt material breaks down and failure occurs.

Once there is a flow path for exhaust gas, the rate of belt deterioration increases because of the extreme heat and the material becomes brittle. Frequent cycling exacerbates the problem. Contact with high-temperature gas also causes the insulation to crystallize. The resulting powder is entrained in the exhaust flow and deposited on the catalyst surface.

Proposals to correct problem were received from two vendors. Both specified changes to the frame and joint materials to eliminate the failure mechanism and allow high-cycle operation. Each proposal included modifications to increase the clearance between the frame faces.

One vendor proposed complete replacement of the frame and improvements in the insulation and wire mesh within the joint. Frame replacement would also require reducing the length of the exhaust duct between the EE00 and EE01 expansion joints. The estimated cost and outage duration to implement this proposed modification was $1.5-2.2 million and 30 days. This proposal was not accepted.

The second vendor proposed modifying the existing frame to achieve the necessary outer belt width and making improvements in the insulation and wire mesh within the joint (Fig 84). The estimated cost to implement was between $150,000 and $175,000; outage time, between three and five days.

The failure mechanism for the EE01 joint was insufficient structural


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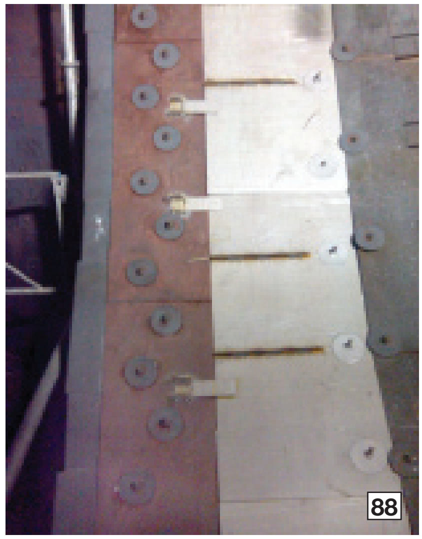
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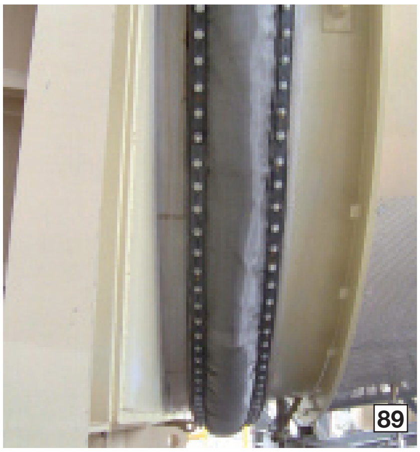
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support of the frame's flange at the frame-to-duct interface (Fig 85). During operation, as the duct sections expanded/contracted and moved differentially, the stiffness of the outer belt material caused the flange to flex and the weld connecting the joint frame to the exhaust duct to fail. A secondary failure mechanism: The outer belt material was not adequate for the operating conditions in this location because of the exhaust duct design.

The proposed modification included (1) addition of gussets to increase the structural strength of the joint frame and flange, thereby preventing flexing at the duct-to-frame weld (Fig 86); (2) replacement of the outer belt with one fabricated from a material suited for the operating conditions; (3) improvements in insulation and wire mesh within the joint similar to those proposed for EE00. The estimated cost and outage duration to implement was $90,000 to $105,000 and three to four days.

The primary failure mechanism for the EE02 joint was insufficient outer belt width (Fig 87). The actual thermal growth of the duct causes the flange face-to-face clearance to increase at the 12 o'clock position and decrease at 6 o'clock. This resulted in the outer belt being stretched and pulling free from the frame, thereby creating an exhaust-gas flow path. In addition, the internal liner plates covering the gap on the exhaust-gas side of the expansion joint were not sufficiently long in the axial direction to cover the gap throughout the range of thermal expansion.

A new frame to include modified and additional pins to attach a liner plate of new design was proposed (Fig 88). The proposal also recommended an increase in outer belt width to accommodate the actual duct movement, as well as improvements to the insulation and wire mesh within the joint (Fig 89). The estimated cost and outage duration to implement was $90,000 to $105,000 and six to seven days.

Results. Wolf Hollow implemented the proposal for the EE02 expansion joints and completed this installation on both units in November 2009. In January 2010, Unit 2 experienced a failure of the liner plate at the 12 o'clock position. The failure was reviewed and the design of the liner plate was modified.

In April 2010, the new liner plates were installed on both units. As of the end of November 2010, there had been no further issues with the EE02 expansion joints. Each unit recorded 195 cycles between EE02 installation in November 2009 and the end of November 2010.

Wolf Hollow implemented the proposals summarized above for the EE00 and EE01 in April 2010. There had been no issues with these joints between installation in April and the end of last November; there were 135 cycles on each unit during that period. Wolf Hollow has monitored quarterly both the condition of the expansion joints via infrared thermography and the differential pressure across the catalyst.

This project began in early 2009 with the goal to eliminate outages, capacity impacts, collateral damage, and reduce the costs caused by expansion-joint failures. The investment in the newly designed expansion joints is on pace to provide a return on investment in less than two years based on historical costs. The new expansion joints have not been associated with availability loss or decrease in catalyst performance since their installation.

Demin-water recirc mod yields big saving

Mill Creek Combustion Turbine Station

Duke Energy Corp

Challenge. Raw water for the plant's eight GE 7EA gas turbines is purchased from the city and stored in the large makeup water tank shown in Fig 90. First processing step is RO, then deionization. Storage of product water is in the demin tank behind the makeup tank in the photo. Makeup water is inherently dirty and RO-system prefilters and membranes are susceptible to rapid clogging and require frequent replacement.

Demineralized water is used only when the units are firing oil, which is infrequently. Thus demin water typically sits in the tanks for long periods with no circulation or usage. The organisms that thrive in the stagnant water can cause rapid clogging of the unit filters critical to unit operation when burning oil. Clogging can be detrimental to starting reliability and availability.

Mill Creek Combustion Turbine Station

640-MW, dual-fuel, simple-cycle peaking facility located in Blacksburg, SC

Plant manager: Randy Spencer

Key project participants:
Joe Costello, CT tech III, lead chemistry technician
Kristi McCall, fleet engineer

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Solution. Plant personnel determined that circulating water from the demin tanks back through the RO system would be of great benefit. After planning and siting the project, excavation to access and modify the existing piping system began. The supply line from the makeup tank to the RO system and the supply line from demin tanks to the turbines were tied together, and a valve placed between the two (Figs 91, 92).

A check valve was placed upstream of the tie on the demin-to-GT line, to prevent contaminating the water in the demineralized tanks. A valve was already in place on the makeup-to-RO line, upstream of the tie. With this one tie, it was made possible to pull from the demineralized tanks, cross into the makeup water line, supply the RO, and then discharge the newly circulated and cleaned water back into the demin tanks.

Results. With the recirculation option, demineralized water is the primary water going through the RO system. This helps keep the water in the tanks from stagnating and prevents clogging of unit filters. Additionally, since clean water is now primarily used in the RO system, the membranes and prefilters will remain clean and last longer.

This modification dramatically reduces the costs of annual filter and membrane replacement as well as increasing unit starting reliability and availability. It also reduces the amount of water purchased from the city for makeup.

From 2008 to 2010, we replaced over 570 prefilters in the RO system at a cost of more than $25,750. We expect that recirculation will reduce the need to replace the prefilters in the RO by 90%. The cost for a full replacement of the membranes in the RO system is around $119,000. By using demineralized water in the RO, we expect the life of the membranes to nearly double. Over a 10-yr period, this would save almost $60,000. Finally, use of demin water in the RO system dramatically reduces the need for, and cost of, makeup water.

Ammonia injection air duct heater

Decatur Energy Center
Calpine Corp

Challenge. Decatur Energy Center (DEC) encountered decreased ammonia dilution- air flow as a result of moisture freezing and ammonia salt buildup in piping orifices during extreme cold-weather operations.

Decatur Energy Center

800-MW, gas-fired, 3 x 1 combined-cycle cogeneration facility located in Decatur, Ala

Plant manager: Mike Gough

Key project participants: Joe Bogle, plant engineer
Scott Parker, operations manager


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Solution. The site conducted a management of design change (MODC) procedure review since this was considered to be part of a process safety management (PSM) system. The decision was to install an ammonia dilution-air duct heater to preheat dilution air during winter operations (Fig 93).

The basic components included a control panel which contained a temperature controller with high-temperature shutoff and a power controller to regulate heater voltage and maintain the temperature set point of the controller.

Additionally, a temperature switch is used for automatic operation and is set to turn the system on at 40F ambient. An interlock from the blower starters will not allow the heater to energize if at least one of the two blowers is not running.

Results. After system installation, the ammonia dilution-air temperature increased dramatically—from freezing ambient temperatures to approximately 90F. The warm air eliminated freezing and salt-buildup problems previously encountered at the piping orifices.

This has facilitated a return to normal air distribution and air flow rates in the SCR. The successful modification at DEC provided the incentive to install the same system at neighboring Morgan Energy Center.

WDPF instrument termination enhancement

Blackhawk Station

Owned by Borger Energy Associates LP
Operated by NAES Corp

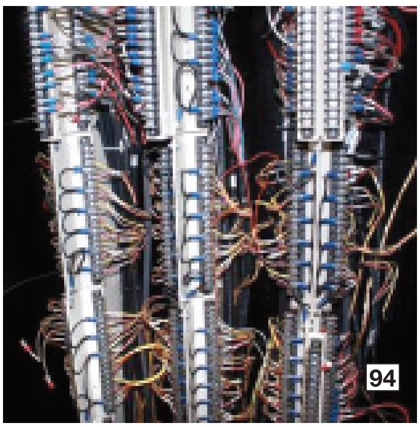
Challenge. Blackhawk Station had experienced numerous thermocouple failures since beginning commercial operation in 1999. These failures caused countless turbine trips from load over a 12-yr period, resulting in lower than desired reliability.

Blackhawk Station

230-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Borger, Tex

Plant manager: Craig Courter

Key project participants:
- Bryan Stout, maintenance supervisor
- Steve Nelson, operations supervisor
- Alan Bull, project manager



Solution. Bryan Stout, maintenance supervisor, has worked at Blackhawk for seven years in several roles including operator and I&E technician. During his time at Blackhawk, he played an instrumental role in troubleshooting several design issues related to the site.

One of the most prominent issues that the site was dealing with was recurring thermocouple failures in the gas turbines. Operators continually reported blade-path thermocouple failures following startup and during normal runs.

Maintenance technicians had tried multiple times to correct the issue and had actually gone as far as moving the wiring harnesses away from the turbines and replacing all thermocouples and pulling new signal wire to remedy the issue. This did not result in any improvement. Technicians then tried replacing input cards but still had the same recurring failures.

Stout had been one of the lead technicians in troubleshooting this issue prior to his promotion. He was convinced that the issue could be resolved and challenged his team to understand the issue and began recording what was done in every instance of failure.

The team then started looking into the design of the instrumentation cabinet (half shell). What they found was that the I/O card connectors were of the push-on type (Fig 94). They were able to mimic a failure by moving these connections in place. They would check each of the connections and screw tightness on the opposite side of the chassis following each failure. This would clear the faulty input. However, upon start up the site would still experience failures.

Stout directed his team to develop a procedure to solder the connections in place. During the following outages they began to solder each connection associated with shutdown points of the combustion turbines. This was a very time consuming process consisting of many connections in a tight place.

Results. This improvement was started in April of 2010 and was completed on both units in June 2010. The site has not experienced a thermocouple failure since. This is a great achievement as the site has never operated for this long a period without thermocouple failures since COD.

ACC gear-reducer condition-based maintenance

Walter M Higgins Generating Station

NV Energy

Challenge. The ACC's 510 × 178-ft main operating deck stands over 60 ft in the air and supports 40 35-ft-diam

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: Dave Rettke, maintenance specialist
Entire Higgins staff

axial fans and their drive systems. Each fan has a gear reducer and two-speed motor that run as needed when the plant is in operation.

The ambient environment is harsh. Temperatures range from 115F in summer to about 20F in winter. The drive unit, including the gear reducer, sits in the middle of the air stream. Each gear reducer requires about 7.5 gallons of Mobilgear Synthetic SHC XMP 320, which has a viscosity similar to that of honey.

Solution. The Higgins O&M staff took ownership of the entire plant during construction and through commissioning. It was decided that a condition-based maintenance program would be integral to maintenance activities and operation of the plant as a whole.

Since the lubricant chosen and accepted by the manufacturer of the gear reducers is more expensive than the usual oil, a joint decision to service each gear reducer according to condition was decided as a best practice to significantly lower operational cost. To achieve this, a sampling/filtering program was developed that would allow maintenance staff the ability to determine the condition of the gear reducer and the lubricant in the best scientific way possible.

Twice a year each gear reducer has an oil sample taken, and immediately after sampling, a portable filter cart is connected directly to the gear reducer. The filter cart's dual filters have the ability to filter down to 10 microns and also remove up to one gallon of water per filter.

The samples are sent in for analysis and the results are checked for optimal operation. If a sample shows high water or contaminant levels, a second sample is drawn. Since filtering occurs right after sampling, the second sampling will show the results of that filtering and if further work is necessary.

The reasoning behind the sampling and filtering program put in place includes the following:

- First is the location of the gear reducers. The ACC structure makes "usual" maintenance difficult at best, making the fewest possible gear-reducer replacements desirable.
- Second, the manufacturer's recommendations are to change the oil every 5000 hours or 18 months of operation at a cost of $21,760 in material with oil at $68/gal. With 40 gear reducers, each requiring eight gallons of oil, the plant needs to purchase 320 gallons of oil.
- Third, changing lube oil on an hourly based schedule isn't

cost effective. Samples of lube oils have shown historically that oil is often changed long before needed. By sampling, the plant can see the actual condition of the oil and know whether or not it needs to be changed.

Results. Since commissioning, only three gear reducers and one oil pump have been replaced. New oil for these fans, plus replacement oil for six other gear reducers in accordance with sampling results, add to a total oil cost of around $5440.

The plant has been in operation since 2004 and there has been only one complete change of lubricant for all 40 gear reducers—the initial 400-hr change. Since then, sampling and filtering have kept changes down to 10 gear reducers, or about 80 gallons of oil.

Had time-scheduled oil changes been implemented, the cost of the estimated four complete changes of lubricant (after the initial 400-hour change) would have been $87,040. The total saving on lubricant alone has been $81,600. This does not include man hours or other ancillary expenses that occur with scheduled maintenance.

Reuse of evap cooler water

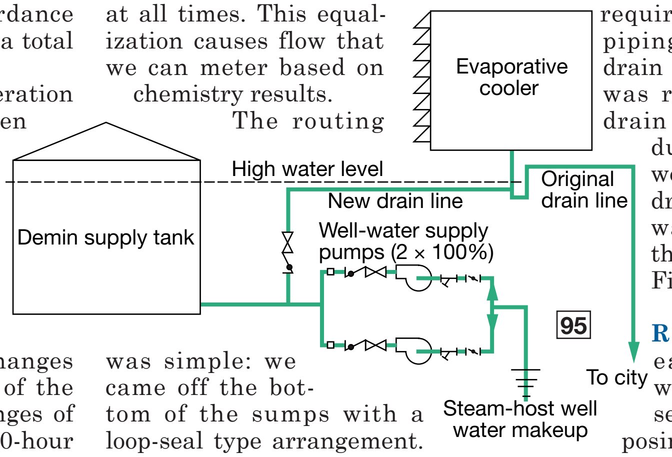
Klamath Cogeneration Plant

Iberdrola Renewables

Challenge. Plants that utilize evaporative cooling for their turbine inlet air often have the sump blowdown going to a waste drain. In our case, that drain leads to the local water treatment plant. The treatment plant faces very high upgrade costs and is in the process of raising our sewer rates 70% over the next three years. The largest contributor to our wastewater discharge was the evaporative coolers, especially in the summer.

Solution. The solution was to capture this water and find a way to reuse it. The only place that this water would be useful to us was boiler makeup water. Of course, it had to be demineralized first. We are fortunate because the condensate returning from our steam host enters our turbine building at the same end of the building as the combustion turbine inlets. From there it goes underground to our makeup water tank.

We decided to tap into this line and allow gravity to be the motive force. Since the normal operating level of the storage tank is slightly lower than the evaporative cooler sumps, the water naturally tries to equalize with the tank at all times. This equalization causes flow that we can meter based on chemistry results.



The routing was simple: we came off the bottom of the sumps with a loop-seal type arrangement. If there are no obstructions to flow, the water goes to the tank. If the tank level is too high or the operator closes the isolation valve, the flow is diverted back to its original design and goes to the drain. This prevents us from overfilling the tank or the evaporative cooler sumps.

The only challenge to overcome was all the obstructions inside the building. These obstructions prevented us from getting the proper slope of pipe to our tie-in destination. Instead, the pipe was routed outside the building and underground utilizing flexible plastic pipe.

Although some trenching was required, most of our outdoor piping used the plant storm drain system. The flexible pipe was routed inside the storm drain much like an electrical duct bank. The two units were joined inside the storm drain and a low point drain was installed for clearing the pipe before winter. See Fig 95 for design details.

Results. The results are easy to quantify. Even without the 70% increase in sewer rates the cost of disposing this water is approximately $20,000 annually. Since we did not have to install any pumps, regulating valves or long runs of pipe, this project paid for itself in less than one summer. The system is extremely simple and operates itself, seamlessly. Other than draining the piping before winter there is no maintenance or operator intervention.

Aside from the monetary benefits, we feel that we are being good stewards of the resources in our care. This project reduces the amount of well water that our host must produce to cover the steam losses in their system, thus saving them money and allowing the aquifer water to stay in the aquifer.

Klamath Cogeneration

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

Plant manager: Ray Martens

Key project participants:
- Greg Dolezal, maintenance manager
- Bruce Willard, operations and engineering manager

Plant lighting project reduces energy use, saves money

Michigan Power

Owned by Michigan Power LP
Operated by Delta Power Services LLC
Affiliates of Olympus Power LLC

Challenge. The plant was faced with the decision to spend budgeted money to relamp existing fixtures with lower efficiencies and higher replacement costs, or use that money to replace/retrofit all plant lighting with higher-efficiency lighting and lower replacement/relamping costs.

Solution. Our commitment to environmental stewardship and cost-effective O&M made it an easy choice to replace and retrofit all plant lighting for energy cost savings and higher efficiency. In addition, occupancy sensors in low-traffic areas were installed to reduce energy costs even further.

Results. Total project cost was $121,395 for labor, fixtures, lamps, materials, equipment rental, etc, to replace, retrofit, and add occupancy-sensor-controlled areas. The cost to re-lamp the existing fixtures would have been $27,772 which includes new lamps, equipment rental, and scaffolding erection and was scheduled for completion in 2010.

The energy service provider offered a rebate incentive program for replacing and retrofitting lighting. The plant reduced the total energy consumed per year by 71,719 W, which qualified for an additional $27,704 rebate from the energy service provider's program. In order to qualify for the incentive program, the plant had to sign up for the Energy Optimization Program (EOP) rate with the energy service provider for at least one year, which added $9187. After one year at the EOP rate, the plant can return to the current rate. This yielded the actual cost for the project to be $67,465.

With annual power savings of $35,413, payback is approximately two years. In addition, the re-lamping frequency of the new fixtures is approximately eight years versus five for the existing fixtures, and the cost of new lamps is only $4226, compared to $9752 for the existing lamps. Another key benefit since the project has been completed is that the light intensity level throughout the plant is greater with the new fixtures.

Michigan Power

154-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Ludington, Mich

Plant manager: Ken Tomaski

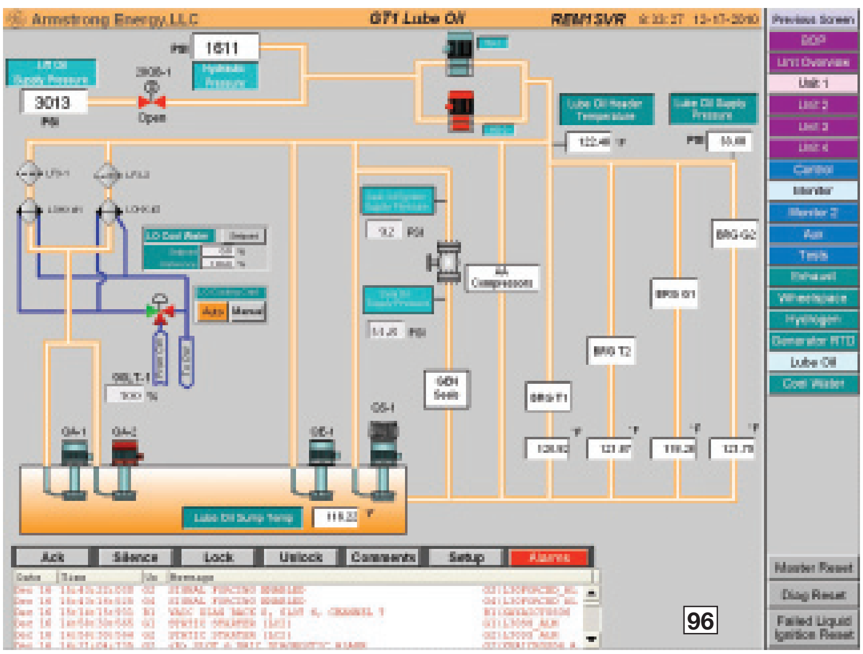
Key project participants:
Danny Cox, plant engineer
Bob VanDyke, I&E technician
Becky Sparks, I&E technician

Instrumentation system improvements

Armstrong Energy

International Power America Inc

Challenge. "We have all the people we need all the time." These words are almost never spoken at a GT-based powerplant in these days of a tight economy and suppressed budgets. With fewer personnel to send to check on pressures, temperatures, and conditions, the need for



improved instrumentation is greater today than ever before.

Solution. The staff at the Armstrong identified its own requirements through a thoughtful, methodical, and practical approach. Regularly scheduled bi-weekly O&M meetings are held at the station to identify upcoming projects and current conditions. At this meeting a list of sensors that would yield the most improvement in operations was developed.

The signals were not provided during the construction of the plant and the OEM relied on local switches and manual gages to provide protection. The list included:

- LO header pressure.
- Hydraulic system pressure.
- Lift oil pressure.
- LO sump temperature and heater control (Fig 96).
- Seal oil system supply pressure.
- Seal oil pressure (Fig 97).
- Cooling water pressure (Fig 98).
- CW inlet temp (to tower).
- CW outlet temp (from tower).
- Hydraulic accumulator pressure.

To incorporate these signals into the DCS, a controls change form was developed to track any changes made to the systems and document those changes for future reference. Sensors were selected based on a variety of factors—including sensitivity, range, and price. Because most of these sensors are used for display only—the only exception being lube oil sump temperature— low-cost sensors were selected.

There were ample spare signal wires already installed in the DCS cabinet which were routed to the appropriate junction boxes in the plant. Transducers were installed near each of the systems local indicators to provide the CRO with a remote reading as close as possible to the reading that a roving watch would report.

Armstrong Energy

625-MW, dual-fuel, simple-cycle peaking facility located in Shelocta, Pa

Plant manager:

Key project participants: Wes Crawford, Jim Mandella, Peter Margliotti, Bryan Miller, and Dexter Cox, plant combustion turbine specialists

Sensor installation was a very simple process in most cases; some conduit work was required. After sensors were installed, screens were created for display on the DCS for display of the data, and existing and new readings were used to allow the operator to better monitor and control the plant.

Another major benefit of these additional sensors was control of the lube-oil sump heater. This heater was originally controlled by a temperature switch which had 115 Vac supplied by the LO heater control MCC bucket. This switch was physically located in the sump secondary containment which in our northern climate, can fill up with snow and ice during the winter months.

The switch would often short together, energizing the heater and overheating the oil. As the OEM had only provided a switch that alarmed only if the sump temperature was below normal, this condition could have gone undetected until a LO pump was started and the tell-tale odor of overheated oil was detected.

By installing an RTD in the sump and bringing the signal into the DCS, a control scheme was designed using the original instrument settings to maintain proper oil sump temperature during idle periods and ensure that heaters were de-energized when not required. Also, because the RTD is a low-voltage signal, a potentially dangerous voltage was eliminated from an area prone to moisture, snow, and ice.

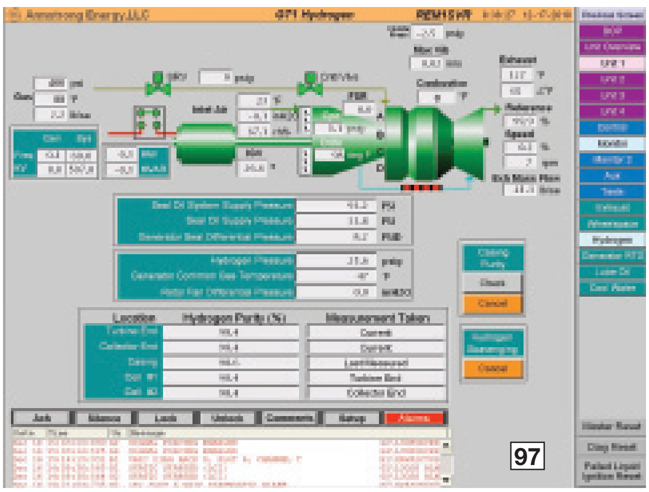
Results. Installation of various instrumentation system sensors and their incorporation into the plant's digital control system allow personnel to more effectively and efficiently operate and monitor the plant's processes from the control room.

Heat-trace system reliability improvements

Jasper Generating Station

South Carolina Electric and Gas Co

Challenge. In the midst of severe winter weather, the generating plant was forced off line as a result of a frozen instrument sensing line. A pressure transmitter impulse line, indicating the steam-turbine condenser vacuum, froze. This resulted from the failure of a HAND-OFF-AUTO



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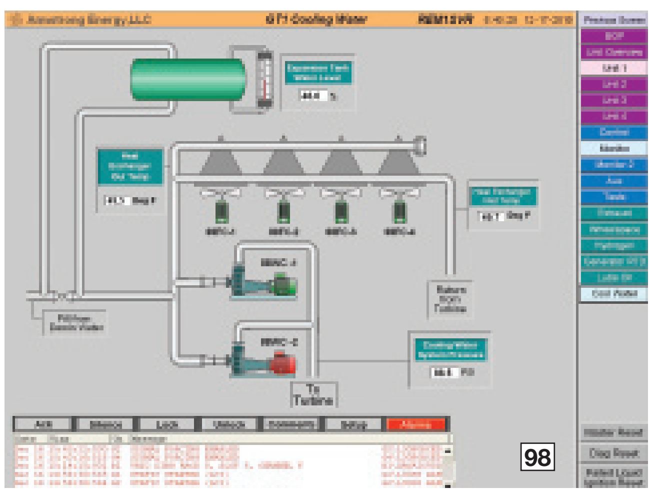

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Jasper Generating Station

910-MW, gas-fired, 3 × 1 combined cycle located in Hardeeville, SC

Plant manager: Steve Palmer

Key project participants:
- Tim Glover, operations superintendent
- Rusty Mezel, maintenance superintendent
- Noah Littleton, engineer
- Kevin Croft, E&I supervisor

switch on the heat-trace panel not "making up" in the AUTO position after the late fall preventive maintenance checks.

There were no alarms presented locally or remotely for the fault condition. Investigating the problem, it was found that the alarm circuit is only energized if the switch contacts are made in the HAND or AUTO position. Restart of the units was further complicated by two other frozen components off of the same heat-trace circuit.

Solution. The faulty switch was replaced. All heat-trace panels were electrically reconfigured so that the local and remote alarm circuits are energized regardless of the position of the HAND-OFF-AUTO switch—as long as the panel "master disconnect" is closed-in.

The remote alarm function was enhanced by adding both the "alarm state" and the "power state" of each of the four heat-trace panels to the closed-cooling-water graphic that CROs normally display on the Ovation® HMI.

Further, a digital, LCD multimeter was installed in each panel door, allowing the auxiliary operators to read the voltage, the current being drawn, and the power used in real time when making their rounds (Fig 99). The metering also serves as a tool for troubleshooting by E&I technicians.

There was a slight variation among the local heat-trace panel thermostats when operating. To address this, the local thermostats that energize the heaters when in AUTO have been replaced by outputs from the DCS, allowing the heaters to energize in harmony.

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Results. The plant has suffered no further instrumentation upsets as a result of freezing weather. Operators have enhanced confidence in the efficacy of the heat-trace system as they are able to now see that it is working.

Time sync of plant clocks ensures data collection accuracy

Arlington Valley Energy Facility

Owned by LS Power Group
Operated by NAES Corp

Challenge. Time settings of plant computers oftentimes are not synchronized. This can cause many issues, such as difficulty troubleshooting sequences of events from divergent data sources. At our plant the problem was manifested in two events that caused us to seek a better approach.

The first was a power grid event causing a protective relay to activate. When collecting historical data from the protective relay and the DCS, it was noticed that the time stamps between the two systems were different. The second was an event with the steam plant causing a steam-turbine trip. When collecting historical data from the Mark VI turbine controls, the generator protection relays, and the DCS, personnel noticed the time stamps among the three systems also were different.

Arlington Valley Energy Facility

570-MW, gas-fired, 2 × 1 combined cycle located in Arlington, Ariz

Plant manager: Greg Nugent

Key project participants:
- Robert Gilmore, I&E tech
- Les Matsumoto, I&E tech
- Ron Sager, production manager
- Alan Tolman, maintenance manager
- Arlington Valley O&M staff

Solution. We approached the problem with a multi-pronged approach. The first solution employed was to install Schweitzer GPS IRIG-B synchronized real-time clocks at all of the generator and main transformer protection relays. This involved three different devices sharing their outputs to the relays at each location.

The second solution was to install another set of GPS time clocks at the main power feeder relays and the main transmission line relays. We also installed a GPS time clock with multiple outputs to send real-time signals to the turbine controls, BOP DCS, CEMs, water plant controls, and inlet chiller controls.

Results. All of the computers used in the operation of the plant and all of the critical relays used for main power feeders, transmission lines, and generator protection are all synchronized using GPS real-time clocks.

After the installation was complete, an event occurred at another powerplant both causing us to lose power and the protective relays to operate. After collecting historical data from the different relays and computers that recorded the event, it was noticed that all of the devices had the same time down to one hundredth of a second.

When troubleshooting a steam-plant event after the project was complete, there was an assurance that the data events were chronologically correct. The result of the improved time- stamp integrity was simplified troubleshooting and assured quality inferences from the recorded data.

Integrating operations, maintenance, technical expertise enables 220 MW

Brownsville Combustion Turbine Plant

490-MW, dual-fuel, simple-cycle peaking facility located in Brownsville, Tenn

Plant manager: Danny Clayton

Key project participants:

Dean Frederick, site foreman
- Carl Byrd, CT technician
- Chris Ritchie, CT technician
- Thomas Robertson, CT technician
- Ron Willis, CT technician
- Frank Herndon, machinist
- Zach Cowart, outage and projects manager
- Clinton Lafferty, senior systems engineer
- Innovative Steam Technologies (IST)
- Wood Group GTS
- Process Control Solutions LLC

Brownsville Combustion Turbine Plant

Tennessee Valley Authority

Challenge. Since commissioning in 1999, two simple-cycle Westinghouse 501D5 gas turbines, each rated at 110 MW with steam injection for emissions control, lacked operational stability when ambient temperatures were below 50F. Both units used once-through steam generators (OTSGs) mounted in the exhaust stack to make steam with a minimum of 50 deg F of superheat.

When ambient temperatures fell below 55F, operators periodically had to manually control the steam system, and as temperatures dropped further, operations had to continuously control steam generation parameters to prevent OTSG trips and likely gas-turbine trips.

Also, since the plant was originally designed as an economic summer peaking facility, feedwater startup control and freeze protection systems were missing or inadequate. During unit startup, control room and outside operators multi-tasked among feedwater flow rate, vent- and drain-valve positions, and unit operating parameters to match steam and combustor pressure for steam injection; all with a likely risk of tripping a unit because of flame blowout.

Previous attempts to tune the two units and adjust the control logic resulted in little to no improvements. With low reliability during cold weather, the units remained unavailable for generation during half of the year.

Solution. Utilizing operation, maintenance, and technical expertise a comprehensive solution was developed focusing on these three major phases:
- Gas turbine and feedwater control logic enhancements.
- OTSG efficiency improvements.
- Critical instrument freeze-protection upgrades.

Originally, the GT variable inlet guide vanes (IGVs) opened at 25 MW, decreasing the exhaust temperatures and reducing OTSG efficiency. Utilizing a control methodology from combined- cycle operations, closed-loop IGV controls provided enhanced exhaust-temperature stability and minimal impact to unit output or heat rate for small temperature changes.

An outside engineering firm developed and implemented the enhanced IGV control logic and additional operator interfaces to improve steam generation startup and system stability during ambient temperature changes.

In combination with IGV controls, a simple addition to the feedwater control logic allowed operations to quickly enable steam injection. The outside engineering firm implemented a feedwater offset bias and control graphic to allow the CRO greater control over the feedwater flow just before and at steam injection—thereby avoiding the need for continuous opening and closing of steam system drains and vents to match combustor pressure. The control graphic was implemented with preset minimum and maximum values and change rates to allow flexibility but protect the OTSG.

While control improvements had the potential to improve operation with ambient temperatures between 40 and 50F, achieving very cold weather operation during ambient conditions less than 30F required additional efforts on the steam generation system. Internal engineering studied these four alternatives:
- Increasing OTSG thermal efficiency.
- Adding exhaust-duct firing.
- Maintaining higher feedwater temperature.
- Enhanced IGV controls only.

Increasing OTSG thermal efficiency via increased surface area showed the greatest benefit for the dollars invested. Consequently, it resulted in the least plant disruption with regards to installing balance of plant systems or environmental permit reviews while allowing the units to operate in temperatures between 0F and 10F.

Upon selecting the concept, the plant owner obtained additional engineering support, component manufacturing, and field installation services from the OTSG OEM, which recommended changing fin pitch on the OTSG tubes from 5 fins per inch (FPI) to nine on two of the six rows of tubes for 23% additional surface area.

The OTSG tube change out was completed during June and July. The internal outage planning organization and OTSG OEM field service crews were able to complete the work ahead of schedule and on budget, allowing the plant to set new generation records.

Finally, O&M personnel focused early in the project on the lack of freeze protection on certain critical instruments. Plant personnel, along with an internal field services crew, installed insulated and heated instrumentation boxes around all water-containing pressure transmitters.

With temperatures below normal in December 2010, additional issues were discovered with the existing feedwater and attemperator freeze protection, as well as instrument air systems. The plant's engineering and maintenance resources quickly responded with freeze protection and piping insulation upgrades to sustain operations below 20F.

Results. As the project phases were completed, the operational impact was immediate:

- IGV control improvements maximized exhaust temperature and were easily enabled and disabled by the operators.
- Feedwater control improvements reduced steam-injection task duration from 5 to 10 minutes to 3 to 5 minutes and allowed outside operators to focus on other unit startup tasks.
- Additional 23% surface area in the OTSG increased steam temperature by more than 120 deg F, allowing the units to successfully operate at ambient temperatures as low as 10F with greater than 100 deg F of superheat.

Along with the critical instruments and more recent upgrades to the feedwater and attemperator freeze protection systems, the two units are providing 220 MW of previously unavailable generating capacity for project cost of less than $1 million.

Protecting plant, personnel during winter storms

Tenaska Virginia Generating Station

Tenaska Virginia Partners LP

Challenge. Without much warning, gusting winds, below freezing temperatures, heavy snow and ice storms can wreak havoc on powerplant operations.

Solution. Over the years, our plant has installed miles of heat tracing, warm sheds, and boxes around critical

outside equipment. We also developed a "winterization" checklist that prepared the plant for operation in severe cold and deep snow accumulation.

The checklist incorporates input from all employees and includes actions to be taken from at least four days before an ensuing storm until after the storm has passed. During the year, cold-weather scenario training is conducted to help prepare personnel for extreme winter conditions. The checklist allows the operators to continue to operate the facility safely without dispatch interruption and includes the following procedures:

1. **Before the storm.** At a minimum, ensure all items on the list below are on hand, tested, and ready for use:

- Verify chemical inventory and emergency order, if necessary.
- Verify food supplies per inventory.
- Verify sleeping supplies and arrangements.
- Ensure shovels and snow removal equipment are readily available.

Tenaska Virginia Generating Station

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

Plant manager: Robert Mayfield

Key project participants:
- Donnie Scott, operations manager
- Sam Graham, maintenance manager

- Maintain site water tank levels high in the normal operating band.
- Arrange for more operators and technicians onsite before the storm.

2. **During the storm.** Procedures for ensuring the safety of employees and executing the plan include these:

- Monitor weather conditions.
- On-shift personnel rest periods.
- Monitor water supplies.

3. **After the storm.** Proceed to the cleanup portion of the plan.

After a series of extreme Virginia snowstorms an employee "storm team" was established to improve the checklist by incorporating lessons learned. The development and execution of the winterization checklist has proven that preparation and training does work and will continue to be used for winter storms to come.

Results. All of the site's preparation was tested in winter 2010 during the two worst consecutive winter storms in Virginia's history. All major county roads within two miles of the plant were closed because of fallen trees, abandoned cars, and other road obstacles (Fig 100). Executing our winterization checklist, we were able to continue to operate the plant at maximum output.

Almost five feet of snow fell in five weeks which resulted in some of the worst outside conditions possible (Figs 101 and 102). With freezing temperatures, blowing snow and ice, and no entrance or exit from the plant, the operators used their problem-solving training to meet maximum dispatch with no interruptions.

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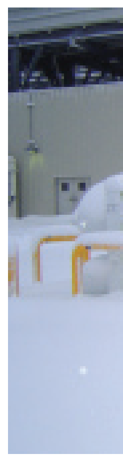


Generator AVR O&M improvements

Osprey Energy Center

Calpine Corp

Challenge. Limited indications and knowledge of status on generator automatic voltage regulators (AVR) can hinder NERC compliance.

Osprey Energy Center

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

Plant manager: Steve Smith

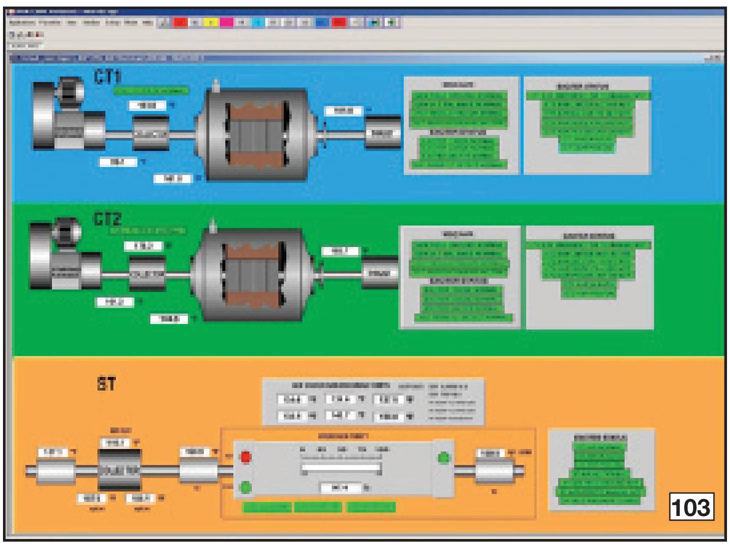
Key project participants:
Gil Kaelin, maintenance manager
Roy Price, lead IC&E technician
Mike Stracener, IC&E technician
Tim Dougherty, IC&E technician

Solution. With a specific focus on NERC compliance, the site examined AVR reliability and mode-of-operation indicators available to operating personnel. Improvements were made in the following areas:

- Review relay outputs that were configured, but not installed, for DCS monitoring.
- Actualize the configured relays to the DCS to give an accurate indication of AVR status.
- In the case of this particular AVR, the unit can perform an "emergency switch to manual" yet still indicate "auto on." Investigation revealed several additional relay outputs from the AVR that could be brought to the DCS for more indication.

- AVR power supply caused interference with receiver boards for diode status transmitters. A changing magnetic field in the proximity of the receiver board caused a change in diode-status indication. The measured magnetic field with the unit at speed an un-excited reading is 0.11 Tesla and when fully excited it is 0.25 T to 0.45T. The receiver board was moved to an enclosure with no changing magnetic field and the problem was solved.
- Alarm indications for receiver boards, voltage regulators, and AVR mode indications were placed on a single screen to give operators single screen view (Fig 103).
- The operating environment for the steam turbine/generator AVR was moved to a climate- controlled building to provide greater life of the components.
- A semi-annual PM to test alarm outputs to the DCS was implemented to ensure alarm indicators are functional.
- I&E personnel established a quick reference guide for local troubleshooting of the AVRs by non-technical personnel to help identify and correct problems during call-out transitions.

Results. Fully configuring generator AVRs to the plant's digital control system increases operator control and monitoring capability while effectively maintaining NERC compliance.



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Hot-reheat warm-up lines reduce cold-start time

Granite Ridge Energy

Owned by Granite Ridge Energy LLC
Operated by NAES Corp

Challenge. Since commissioning, Granite Ridge Energy (GRE) has been challenged by a significant hold up in getting the hot-reheat (HRH) steam conditions within parameters prior to coupling the steam turbine during cold starts. A historically low frequency of cold starts militated against improving this condition. However, the recent change in the regional bulk electric system's needs suggested that GRE reconsider its position.

Solution. A study of the situation was performed to determine the best actions to undertake for improving cold-start time. Suggestions considered included the addition of larger drain lines immediately upstream of the steam-turbine induction valves at the existing drip pots and back-feeding HP steam to the HRH line to achieve the desired steam conditions faster.

GRE decided that the best course of action was to install additional drain lines leading from the HRH steam lines to the steam-turbine drains tank. Atmospheric venting and routing to the condenser was dismissed. Design of the drains tank was reviewed to ensure it could take the additional pressure and thermal loading and was found to be acceptable.

Next was to determine necessary line size. GRE determined that a 30-min minimum cold-start improvement would be necessary to justify the expense of the upgrade. A local engineering firm was hired to determine necessary line size. Calculations determined that a 2-in. line from each HRH inception line would suffice.

Necessary considerations to line routing

included the need to allow for thermal movement—including steam-turbine thermal growth, materials, valve selection, safety concerns, valve placement to platform location, proper support, and negotiating existing piping runs and support steel. A final plan was designed and implemented during a routine maintenance outage. Operating procedures have been altered and will be finalized as greater experience with the upgrade occurs.

Results. The installation of these lines has provided a safe and effective method for minimizing cold-start time. GRE has experienced relative saving of upwards of 50 minutes of time which equates to approximately $10,000 of startup gas. If future cold-start frequency mirrors that of the first quarter of 2010, this upgrade may allow complete return of investment within half of a year and significant savings onward.

Granite Ridge Energy

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

Plant manager:
William Vogel

Key project participants:
Larry Hawk, plant engineer
Jim Golles, control room operator
Dan Jorgensen, maintenance manager

Initiatives, procedures improve operating reliability

New Harquahala Generating Co LLC

Owned by MachGen Holdings LLC
Managed by Competitive Power Ventures
Operated by NAES Corp

Challenge. The plant, consisting of three combined-cycle units, began commercial operation in September 2004; it sells capacity and energy into the WECC market. From the beginning of a contested transfer of care, custody, and control, facility personnel have been committed to achieve best-in-industry operating statistics. Last year marked the pinnacle of a process that showed continuous positive outcomes.

New Harquahala Generating Co LLC

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

Plant manager: Dean Motl

Key project participants:
Jacob Mattingly, operations manager

Solution. Plant personnel have shown unwavering determination to improve operating reliability, by implementing or dramatically improving several key programs and policies. The effort was made to ensure that the substantial investments made to correct equipment shortcomings were complemented by the best possible operating standards and practices available.

The facility began by completely revamping all operating procedures. Along with the common goals of ensuring the procedures are accurate and consistent, keen attention was paid to making the procedures concise, visible, durable, and ultimately attractive to use. To achieve this, two official versions of each procedure were created—one long form, one short.

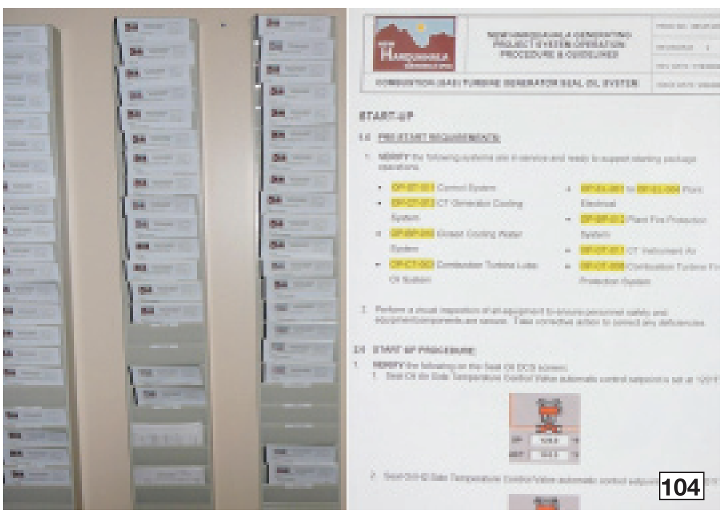
The short form cut out all content not directly related to an operational action. In completed format, the "user" version or short form of each procedure begins page one with system start up directives. To keep the procedures short and maximize utility, graphics and pictures were incorporated as often as possible.

When completed the final revisions of each procedure were printed in color on ineffaceable paper and placed in a sturdy binding. Lastly, the procedures were given a visible and user friendly storage arrangement that paid consideration to ensuring they could be obtained expediently during plant evolutions (Fig 104).

To complete this task, responsibility for the final outcome relied strictly on the operations manager and the most senior operator. A large portion of the work was delegated to the individual operators and they were given guidance documents along with one-on-one coaching to ensure a consistent outcome.

It wasn't enough to rely on individual procedure pre-start requirements. To truly establish a consistency with plant startup preparations, personnel generated a site-specific and comprehensive platform for all pre-start readiness efforts. This ultimately condensed down to a one page "pre-start checklist" that must be filled out and submitted to management with each scheduled startup (Fig 105).

The form was created with versatility enough to cover any startup scenario. It predicates some of the essential actions to be taken prior to issuing a startup command for the GTs, based on a layout that begins 24 hours before, and extends to, the actual time of startup. As with most power production facilities, the oncoming shift of employees responsible for the startup is typically not the same group responsible for preparations. Since the advent of the pre-start checklist, each operating crew can now expect repeatable and reliable plant operating conditions after completing shift turnover prior to an



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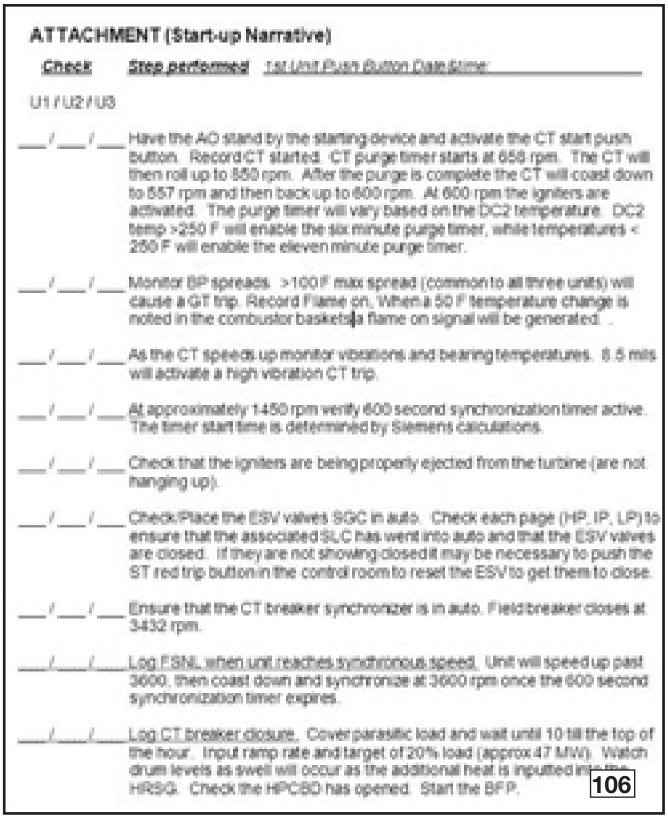
ATTACHMENT (Start-up Narrative)

Check Step performed 1st Unit Push Button Date/time:

U1 / U2 / U3

___/___/___ Have the AO stand by the starting device and activate the CT start push button. Record CT started. CT purge timer starts at 656 rpm. The CT will then roll up to 850 rpm. After the purge is complete the CT will coast down to 557 rpm and then back up to 600 rpm. At 600 rpm the igniters are activated. The purge timer will vary based on the DC2 temperature. DC2 temp >250 F will enable the six minute purge timer, while temperatures < 250 F will enable the eleven minute purge timer.

___/___/___ Monitor BP spreads. >100 F max spread (common to all three units) will cause a GT trip. Record Flame on. When a 50 F temperature change is noted in the combustor baskets a flame on signal will be generated.

___/___/___ As the CT speeds up monitor vibrations and bearing temperatures. 8.5 mils will activate a high vibration CT trip.

___/___/___ At approximately 1450 rpm verify 600 second synchronization timer active. The timer start time is determined by Siemens calculations.

___/___/___ Check that the igniters are being properly ejected from the turbine (are not hanging up).

___/___/___ Check/Place the ESV valves SGC in auto. Check each page (HP, IP, LP) to ensure that the associated SLC has went into auto and that the ESV valves are closed. If they are not showing closed it may be necessary to push the ST red trip button in the control room to reset the ESV to get them to close.

___/___/___ Ensure that the CT breaker synchronizer is in auto. Field breaker closes at 3432 rpm.

___/___/___ Log FSNL when unit reaches synchronous speed. Unit will speed up past 3600, then coast down and synchronize at 3600 rpm once the 600 second synchronization timer expires.

___/___/___ Log CT breaker closure. Cover parasitic load and wait until 10 till the top of the hour. Input ramp rate and target of 20% load (approx 47 MW). Watch drum levels as swell will occur as the additional heat is inputted into the HRSG. Check the HPCBD has opened. Start the BFP.

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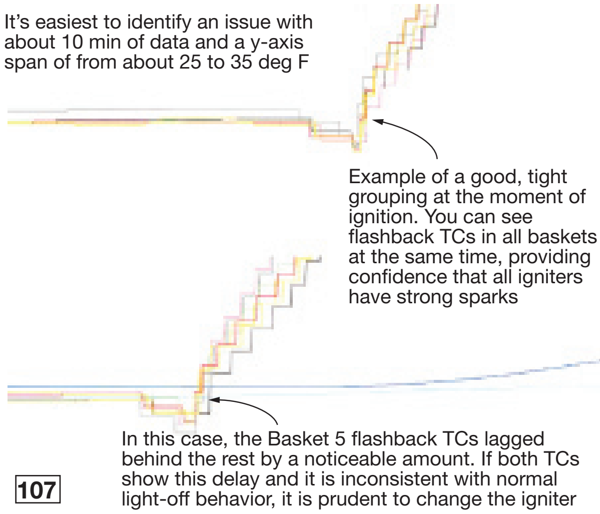

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Performance statistics

Parameter	2008	2009	2010
Availability factor, annual, %	81.4	89.0	90.6
Availability factor, June-Sept, %	91.3	99.9	98.9
Forced-outage factor, annual, %	0.7	3.2	0.3
Forced-outage factor, June-Sept, %	0.1	0.1	0.6
Reliability factor, annual, %	99.3	96.8	99.7
Reliability factor, June-Sept, %	99.9	99.9	99.4
Starting reliability factor, %	88.7	79.0	100

actual startup.

Also incorporated throughout the pre-start checks are specific performance validations completed on sensitive and critical plant equipment. For example, all major valves are loop- checked and stroked to ensure reliability prior to start. This habit of checking equipment functionality came full circle when the OEM unveiled a starting-reliability upgrade option that included most of the content in manual our pre-start checklist. The plant opted out of the upgrade simply because it was merely an automated version of our checklist.

Mated with the pre-start checklist was the creation and implementation of a "startup narrative" checklist to cover any startup scenario. It was written to chronologically depict all of the critical actions of a successful startup in a concise and abbreviated format (Fig 106).

Ideally, this narrative does not directly dictate operator action but is simply used as a tool by the CROs to help prevent any procedural oversight. Requiring the use of this tool has aided in the effort to improve consistency of startup performance and methodology. More importantly it is quick and easy to use for employees who want some reassurance that they didn't miss anything—especially when a startup includes a couple of unexpected surprises.

Developing some of these new procedural resources allowed the facility to recognize and incorporate mitigating efforts for some of the known system- or machine-specific issues. In particular, this plant is faced with a design that incorporates an igniter or spark plug for each combustor known to negatively impact reliability. It is a fleet-wide problem that is all but guaranteed to negatively impact operating statistics. Not settling for the occasional "fired abort," personnel worked together to come up with a trending analysis to predict an igniter failure before it occurs.

As part of the pre-start checks, flashback temperature trends from the last startup are analyzed. If the "signature" of the trend has changed, the igniter is replaced. This last year alone the facility has detected two damaged igniters before they could have caused a failed start. Specific trend templates were developed in the DCS and training documents were made to ensure that everyone involved is looking for the same symptoms (Fig 107). The moral of the story here is not to wait for the OEM to validate solutions to its known equipment deficiencies but rather use site resources to minimize the harmful outcomes.

The facility was able to fully implement these procedural improvements before the end of 2009, which allowed for a clear assessment of their impact by evaluating outcomes of 2010. Along with the familiar plant operating statistics presented at the beginning of this article, this facility methodically tracked and recorded any incident that negatively affects power-generation schedules.

For years the facility has been producing and indexing generation-incident reports (GIR). The requirements to produce GIRs range from full-load trips to the smallest possible load shedding protective function and cover every possible startup interruption. Not only do these reports ensure effective corrective actions are taken to prevent a similar recurrence but they provide a powerful assessment tool to determine how well a plant is truly doing.

Results. With the help of the aforementioned improvements our plant was able to have a year-over-year decrease in GIRs between 2009 and 2010 of 81 to 10. Additionally, most of the 10 incidents in 2010 were very minor. Site personnel are extremely encouraged by these accomplishments and are looking forward to maintaining a facility with the highest possible reputation. As the saying goes, "The only thing harder than getting to the top is staying there."

In 2010, on top of doing major planned outages, the facility realized a 90.6% availability factor, 99.7% reliability factor, and an unprec-

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109

edented 100% starting reliability (table). This is a far cry from a facility that suffered owner bankruptcy during construction, EPC contractor abandonment, required over half of all I/O wires to be remade, and received a plant-wide batch of instrumentation transmitters later discovered to include manufacturing defects (to name a few).

Volumes of literature can be produced to cover the list of discrepancies and solutions related to this facility's effort to improve reliability. With the support of a very cooperative asset manager, we did the heavy lifting that is ultimately responsible for the practically flawless statistics of 2010.

This facility has successfully and dramatically improved the standards of operating reliability by implementing industry leading programs and procedures. By updating and reformatting procedures, adding to operating readiness requirements, ensuring consistency and continuity of operations, and diligently tracking generation upsets, the facility has effectively improved its standing as a reliable power provider.

The work completed to achieve recent successes was several years in the making and relied almost entirely on onsite management and personnel. Without the methodical and determined approach to complete and implement these powerful tools the facility would surely have not achieved a remarkable 100% starting reliability.

For those wondering how this sort of effort is completed start to finish, remember the words of Henry Ford, "No job is too big if broken down in to small-enough parts." Therein is the secret to developing first-class programs for a generation facility.

Whiting Clean Energy

525-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Whiting, Ind

Plant manager: Richard Maroney

Key project participants: Full team effort

Blast protection for contractor personnel

Whiting Clean Energy

BP

Challenge. Standard wood- or metal-frame portable buildings onsite were aging, providing limited blast protection and an uncomfortable work space for contract employees.

Solution. Plant staff decided to replace old modular buildings with new steel-reinforced, blast-resistant modules (BRM) that are designed to withstand blasts of up to 10 psi at 125 psi/msec.

Results. The new BRMs provide a safe and comfortable working area for the site's contract employees (Figs 108 and 109). They serve as an office and meeting area for the craft workers. An added benefit of the BRMs was the ability to stack them vertically. This allowed for a smaller footprint while still providing the same amount of usable office space.

Introducing
www.integrating-renewables.org

"Integrating Renewables into the Generation Mix: Challenges and Unknowns," a special workshop presented by CTOTF in cooperation with NV Energy, in Reno, Nev, September 13, received high marks from the more than 100 participants.

It was clear from the presentations that intermittent renewables (wind and solar) are positioned by state Renewable Portfolio Standards to be come a "game-changer" in terms of grid operation and generation asset management. Depending on RPS, grid, and market specifics, some sections of the country could face system reliability issues in only a year or two.

Over time, strategies and tactics for dealing with intermittency and other idiosyncrasies of the new energy resources will emerge. But as in any transition, developing the solutions required will be challenging and time consuming.

The goal of **www.integrating-renewables.org** is to enable the free flow of information and ideas, share experiences, identify best practices, etc, to facilitate the transition to the new paradigm. Discussion forums include grid operations, smart grid/DSM, O&M impacts on conventional generation, and energy storage. Register today; no charge.

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PSI Media

Eliminating valve sticking improves starting reliability

Athens Generating Plant

Owned by MachGen Holdings LLC
Managed by Competitive Power Ventures
Operated by NAES Corp

Challenge. Athens has three 1 × 1 combined cycles powered by 501G gas turbines, which use steam for cooling transition pieces. Since commissioning in 2004, Athens has experienced sticking of transition steam outlet valves. When valves stick, the unit unloads and late startups occur, which has caused a loss of over 18,000 MWh of production between 2004 and 2008.

During startups, when no steam is available, the transitions are cooled with air provided from the last stage of the compressor. At 20% load, the engines are transferred from air to steam cooling. This step is required to increase load.

During the transition of cooling from air to steam, a series of valves open and close in a very critical sequence (Fig 110). If a valve sticks for more than 15 seconds, the unit will be unloaded to below 20% of rated output. Unit load must then be stabilized, and the unit allowed to heat back up, before the transition from air to steam cooling can be attempted again. During this period, load cannot be raised and the startup is delayed.

The designed arrangement presents a very difficult service for the transition steam outlet control and block valves, which sit with ambient temperature on one side and 800F steam on the other (Fig 111). The valves have a tendency to stick at random times under all startup conditions.

Athens Generating Plant

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

Plant manager: Dan DeVinney

Key project participants:
Ed Malone, PE, plant engineer
Jim Fitzpatrick, division director
Ian Goepferd, project manager
Entire Athens staff

Solution. Plant staff made multiple attempts to eliminate the valve sticking problem, all of which achieved limited success:

- Contacting the valve manufacturers, who recommended trim changes to eliminate the problem.
- Modifying the valve positioners to increase their operating speed.
- Cycling the valves prior to each startup.
- Leaving the valves partially open to pre-warm the valves prior to use.
- Modifying the piping to reduce pipe stress in the area of the valves.

In late 2008, plant staff proposed installing a valve warming system to pre-warm the valves, thus eliminating the temperature differential. Working with Team Industrial Services Inc, the plant designed a heating system that consists of custom-braided heating blankets, K duplex thermocouples, a 480/220-V transformer, and a two-zone control console. The valve insulation was also replaced as part of the project to improve insulating capabilities and maintain the valve temperatures over longer periods.

The first warming system was installed on Unit 2 during a scheduled outage in November 2008, and then commissioned that December. Prior to unit startup, the heaters are


110


111

turned on to slowly raise the valve body temperatures to 600F.

The control console (Fig 112) maintains a specified ramp rate and has dual thermocouple inputs in case there is a thermocouple failure. A failed thermocouple will shut down the heaters as a safety feature to prevent overheating of the valve. The console controls the temperature ramp by varying the output voltage between 0 and 85 Vac. The supply power (480 V) for the unit was provided via a new welding outlet in a dual effort to improve reliability while adding an additional welding outlet for use during outages.

Results. The heaters were deemed a success after multiple startups, and the decision was made to add the heaters to Units 1 and 3. Both of these units were retrofitted in 2009. Since the installation of the heaters, Athens has had over 225 starts and hasn't had a single issue related to a valve sticking. The units have held up very well, and no maintenance has been required on the heating systems to date. The installation of the valve heaters has been a very successful project and paid for itself in avoiding just one failed startup.

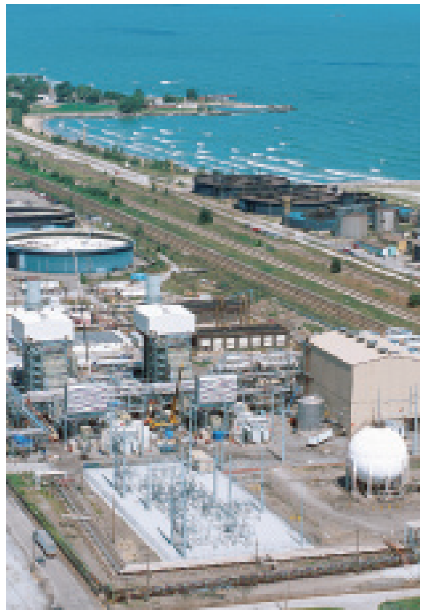
Improved brush change-out procedure

Whiting Clean Energy

BP

Challenge. Changing unit exciter brushes (Fig 113) is time-consuming, potentially dangerous, and inefficient, thereby reducing the plant's overall safety and reliability.

Solution. After researching cur-

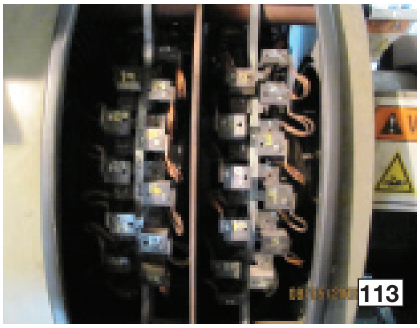


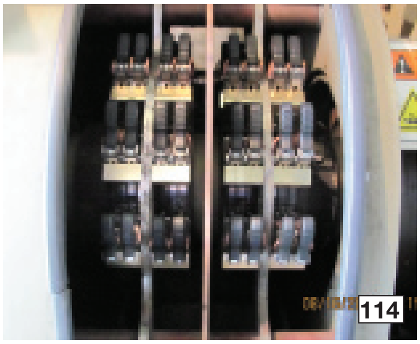
Whiting Clean Energy

525-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Whiting, Ind

Plant manager: Richard Maroney

Key project participants:
Full team effort





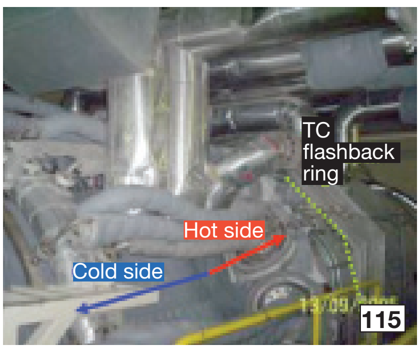
rent products on the market, the site contracted Cutsforth Inc, Cohasset, Minn., to install a new style brush rigging system and new brushes (Fig 114). The EASYchange brush-rigging system reduces the time required to replace an individual brush from 30 minutes to five and eliminated the requirement to bring the unit out of service during brush changeout. This is accomplished by utilizing a preloaded, interchangeable brush holder, pulling the release lever, removing the old holder, then sliding in the replacement.

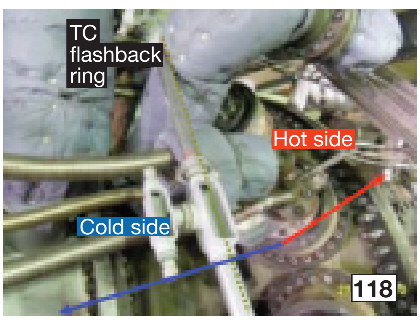
Results. The brushes can easily and safely be changed out with the unit in operation. Using Cutsforth's brush holders results in safer brush changes and increases efficiency by reducing the time required for changing brushes. The system also allows for fewer forced outages with resulting lost revenue for brush maintenance.

Flashback thermocouple ring relocation

Central de Ciclo Combinado Saltillo

Mitsui & Co Ltd and Tokyo Gas Co Ltd





CCC Saltillo

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

Plant manager: René Villafuerte

Key project participants:
Gerardo Rasgado, I&C coordinator
Roberto Hernández, maintenance manager

Challenge. The two flashback thermocouples from each of the 16 combustors on the W501FD are channeled inside a ring that is originally located on top of the combustion shell (Fig 115). Through the history of the plant several problems attributedto overheating, melting, and wire insulation failure have caused many incidents, even an auto-unload.

During past outages, some refurbishment was made so to that thermocouple ring would be further from the heat (Fig 116), but the problems appeared again. On the "hot" side (combustor area) the temperature could reach up to 110F after the insulation blanket and the radiant heat soaked into the electric duct (the ring) causing a slow insulation degradation.

Solution. During the last major inspection outage in October 2010, the flashback thermocouple ring was completely rebuilt, but in this case, the new design was relocated around the "cold" side (compressor area) about 4 ft upstream and expanded in diameter (Figs 117 and 118). Temperatures on the compressor side are no more than 100F after the insulation blanket but with no radiant heat, and the instrumentation conduit remains quite cool.

Results. Relocating the flashback thermocouple ring on the "cold" side (compressor side) eliminated the incipient failures that were common after unit startup and thus enhanced significantly the reliability and availability of the gas turbine.

Blade-path 'footprint' tracking

Central de Ciclo Combinado Saltillo

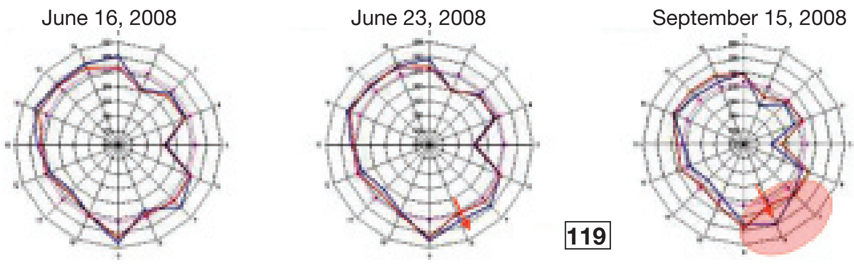
Mitsui & Co Ltd and Tokyo Gas Co Ltd

CCC Saltillo

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

Plant manager: René Villafuerte

Key project participants:
Juan Diaz, operations manager
Roberto Hernández, maintenance manager



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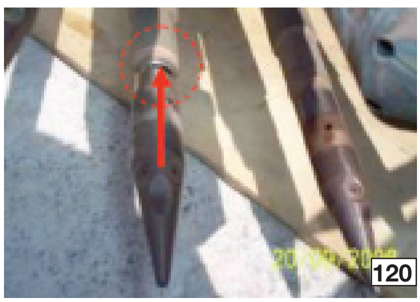

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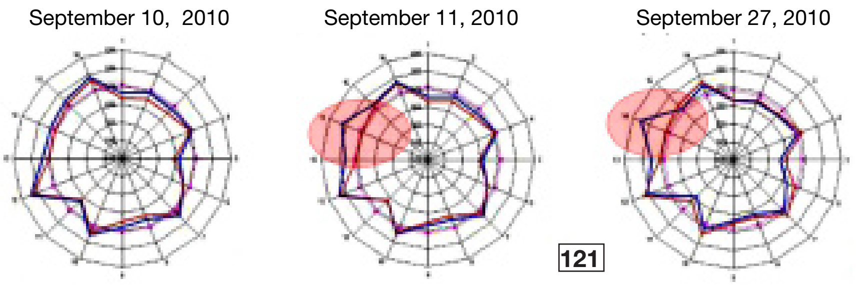
Challenge. Combustors are subjected to severe operating conditions and this hardware sometimes suffers cracks or failures before completing its useful life estimate (8000 EOH between refurbishments in this case). Some parameters, like blade-path (BP) spread or variance, are the first signs of a problem, but to predict or locate the failure, it is necessary to have another kind of tool.

Solution. The W501FD has an arrangement of 16 BP thermocouples (one for each combustor) in order to have a reference for the exhaust temperature. Theoretically, the temperature of the 16 TCs should be the same as the average temperature, but because of the normal differences in the hardware, there are some differences in those values.

If we make a polar graphic at the beginning of operation of the combustion turbine or after the hardware replacement in the outages, there is a characteristic "footprint" that should remain the same until the next hardware replacement during an outage.

Results. Using BP footprint tracking, plant staff reviews the results daily during its morning O&M meeting. To date, we have used this predictive-maintenance indicator to locate at least two hardware failures:

Case 1. In June 2008, the footprint suffered a deformation in BP thermocouple No. 8 over a period of



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14 days (Fig 119). According to the recommendations of the OEM, readings don't match to the same combustor position, but are displaced three combustors counting counter-clockwise. In this case, it was combustor No. 5. During the September 2008 outage, we found a crack in one of the stage B rockets that caused a slight over-fuel condition (Fig 120). In this case, there were no operational consequences before the outage.

Case 2. In September 2010, the footprint suffered a fast deformation in the BP thermocouple No. 14 (combustor No. 11) over a period of two days and the BP variance began to increase at 60% load (Fig 121). During the October 2010 outage, a loosening of the pilot nozzle was found in this combustor (Fig 122). While it did not release any FOD, the resulting over-fuel condition caused the variance.

Because of the rapid change and the variance increase, it was decided to change operating parameters and not to decrease the load to prevent any kind of trip, avoiding a failure on restart. During the load reduction to take the unit offline before the outage, the unit did trip on variance. The forecasted failure on restart would have been a real problem and the decision to not decrease load and remain at full load was correct to avoid losing availability and revenue.

Gas turbine instrument air enhancement

Blackhawk Station

Owned by Borger Energy Associates LP
Operated by NAES Corp

Challenge. While at base-load operation Blackhawk Unit 1 unloaded from 112% to 60%. Normalized load recovered but was followed by an auto-unload and unit trip. After examining the operating data, the site team concluded that the instrument air pressure dropped from 100 to 22 psig during this event. This caused the main fuel valve to slowly close which starved the turbine of fuel, and in turn, resulted in the hydraulic stage fuel valves being opened by control logic to compensate for the low fuel flow.

The air pressure drop was momentary and when it recovered, the main fuel valve opened back up resulting in over-fuel of the turbine. Subsequent damage resulted in having to replace all combustor and hot-gas-path components; peak-period availability was low as a consequence.

Solution. The site had struggled in the past with moisture in the instrument air supplied to the turbine enclosure. In an effort to deal with the high moisture, the site installed a secondary air dryer that only treated air supplying the enclosure.

A packaged system was installed and had worked well for several years. Within the system there is a shuttle valve that switches air flow between two desiccant filters. The root cause analysis of the failure identified that this was the only point that could cause a momentary loss of control air. Disassembly of the valve revealed a high amount of wear and fouling.

This situation prompted an engineering review of the air supply system and safety shutdown of the gas turbines. The first step to addressing the problem was to design and implement a third source of dry instrument air after the auxiliary dryer. This was achieved by plumbing an alternative air line from the main air dryer system.

The original system was configured in a way that main turbine compressor bleed air and auxiliary compressed air would provide pressure to a regulated system. The GT instrumentation would be fed by the auxiliary air system during startup until sufficient compressor bleed air was established. This is achieved by placing the two systems through regulators with the auxiliary air being set at 5 psi less than the bleed air.

In the new configuration, a third air supply is available to the unit; it is set at 5 psi less than the auxiliary air supply. The third system is also integrated into the system downstream of the auxiliary air dryer. This allows the new air system to be unobstructed in the event that the primary and secondary air supply are obstructed.

Blackhawk Station

230-MW, gas-fired, 2 × 1 combined-cycle cogeneration facility located in Borger, Tex

Plant manager: Craig Courter

Key project participants:
- Steve Nelson, operations supervisor
- Bryan Stout, maintenance supervisor
- Alan Bull, project manager

The second step to completing the upgrade was accomplished by implementing turbine control logic designed by the OEM that will shut down the turbine if the fuel-gas pressure drops to within 100 psi of the combustor shell pressure; the operator receives and alarm. Auto-unload is initiated at 70 psi and a trip is initiated at 40 psi above shell pressure. Fail over testing was conducted following all improvements and the system is functioning well. The site has now implemented both the physical and control logic changes on both units.

Results. In response to an over-fuel event caused by a drop in instrument-air supply pressure, plant personnel performed and implemented a comprehensive engineering review, repairs and upgrades, and enhancements to the plant's digital control system, thereby significantly improving reliability and cost avoidance by over-fuel events.

Borescoping steam-turbine stop/control valves

Tenaska Lindsay Hill Generating Station

Tenaska Alabama Partners LP

Challenge. During cold starts and minimum load operation, the steam-turbine stop/control valves are required to operate at the lower end of their control band. When the valves are operated at less than 20% open, the velocity of the steam that passes through them is greatly increased and has the potential to cause erosion of the valve components. A regular inspection is the only method to determine if any erosion has occurred. Disassembly of the valves is costly and requires a lengthy plant outage.

Solution. The plant installed inspection ports using the existing after-seat drain piping on the stop/control valves. A piping tee was installed in the existing 2-in.

Tenaska Lindsay Hill Generating Station

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

Plant manager: Robert Threlkeld

Key project participants:
Mark McKenzie, operations manager
Vince Crabtree, maintenance manager
Claude Couvillion, O&M support manager


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drain line for borescope inspection. The valve stem and body can now be inspected by removing the inspection cap from the tee. At the completion of the inspection the cap is welded back into place.

Results. The borescope ports have reduced the cost to perform the inspection of the steam-turbine stop/control valves by about 90% and reduced the outage time by several days.

Igniter storage rack system

Granite Ridge Energy

Owned by Granite Ridge Energy LLC
Operated by NAES Corp

Challenge. Granite Ridge Energy has a 501G gas turbine with 16 igniters. With the high number of igniters, starting reliability had become an issue within the fleet and at GRE. Plant staff desired to increase lifespan and reduce the cost of expensive igniters while keeping unit reliability as high as possible.

Solution. The maintenance staff created a rack to hold the igniters in place following removal and during transport (Fig 123). This rack system gave a fixed place for igniters that would prevent damage to both cables and igniters themselves and provides secure storage during the outage.

Results. As past igniter failures were not tracked reliably, the exact starting reliability improvement cannot be calculated. However, based on plant personnel feedback and tracking of igniter failures since, the igniter failures certainly have been reduced significantly.

Granite Ridge Energy

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

Plant manager: William Vogel

Key project participants:
- Dana Troian, maintenance technician
- Dan Jorgensen maintenance manager

High-delta-p investigation identifies HRH piping cracks

Tenaska Central Alabama Generating Station

Tenaska Alabama II Partners LP

Challenge. Plant personnel found that the steam turbine experiencing higher than normal exhaust backpressure. The operators noticed that the backpressure dropped whenever the hot reheat (HRH) bypass valves were opened.

Solution. The LCRO came up with the idea to perform a test to determine the relationship between the HRH bypass-valve operation and the turbine-exhaust backpressure. During a plant startup, the steam pressure was increased in the HRH piping and steam was observed coming through the insulation downstream of the Unit 3 HRH bypass valve.

The pipe insulation was removed and it was determined that the steam was coming from a crack in the weld that connects the HRH bypass valve to the downstream P91 piping. The valve was closed and the sound of air being sucked into the crack was heard.

A plant outage was taken to grind out the cracks and make weld repairs. The repaired areas will be inspected during future scheduled outages. In addition, manual block valves will be installed downstream of the HRH bypass valves in 2011 to allow repairs to the valves and piping to be made without requiring a full plant outage.

Results. Steam-turbine backpressure has since returned to normal. Backpressure is monitored regularly during plant operation using an Excel® model that compares the actual backpressure to the condenser manufacturer's design backpressure curves based on the circulating-water temperature and condenser heat load.

Tenaska Central Alabama Generating Station

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

Plant manager: Robert Threlkeld

Key project participants:
- Brian Pillittere, plant engineer
- Alan Foether, LCRO
- Cecil Boatwright, operations manager

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 nine judges for 2011. 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:

- Five judges are located at their companies' headquarters sites and have engineering and/or management responsibilities for multiple generating resources; four are plant managers.
- 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.
- Two judges are experts 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: Management, Environmental Stewardship, Safety (two categories: Procedures & Administration and Equipment & Systems), Design, and Operations and Maintenance (three categories: O&M Business, Major Equipment, and 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 like last year. A total of eight Best of the Best plaques will be awarded in 2011. CCJ

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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 2012 Best Practices Awards program (instructions at www.psimedia.info/bestpractices.htm).

To better gauge how your entries might be rated, consider evaluating the 2011 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 =		

Generator condition monitor critical to avoiding catastrophic loss

By Clyde V Maughan, Maughan Generator Consultants

Editor's note: The core monitor had an early history of invalid alarms caused by issues not related to generator overheating. Because responding to an alarm involved high cost to the owner, it became common industry practice to ignore the device—despite the fact that some alarms were indeed valid.

Early detection of burning inside a generator is of great importance to owner/operators and significant effort has been expended to improve the reliability of the core monitor and make it easier to use. These efforts involved both present suppliers of the equipment, Environment One Corp and General Electric Co, as well as others. By 1989, a mature design had been achieved and more than 500 Generator Condition Monitors (GCM) have been put in service since.

Based on recent EPRI surveys and other data sources, the post-1989 monitors are performing well, with infrequent invalid alarms. The number of valid alarms also is small—more than half of the 20 reported are profiled in this article.

But because of the highly destructive nature of these failures, the potential saving has been great. A single failure can cost more than $15 million in repairs alone; business interruption penalties can far exceed that. Correct response to the infrequent alarm has been enhanced by the capabilities of today's distributed control systems.

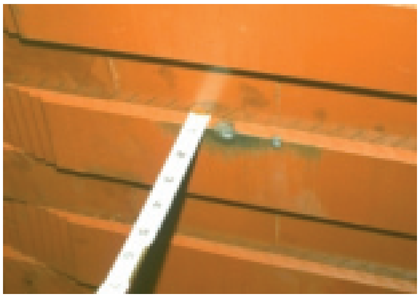
Simply put, if properly maintained and operated, the GCM can mean the difference between a brief shutdown for minor repairs and a major overhaul involving weeks, possibly months, of costly downtime.

Generator monitoring capability historically has been limited, with many common failure mechanisms monitored imperfectly or not at all. Examples of inadequately monitored thermal failure mechanisms on generator stators include stator core lamination insulation failure (Figs 1, 2), cracks developing in stator conductors (Fig 3), and loss of cooling (Fig 4). On field, unmonitored failures that generate high temperatures include cracking of field conductors (Fig 5), shorts (Fig 6), and grounds developing because of field coil/turn distortion (Fig 7).

Limited monitoring capability has been troubling to both generator manufacturers and powerplant O&M personnel. Failure caused by overheating of the stator core iron is a particular concern. While this type of generator failure is not common, when a core fails it usually causes extensive damage, with associated expensive repairs and outage time.

The Generator Condition Monitor (GCM) discussed below is a thermal monitor developed to address overheating concerns. Today it can detect the very early stages of localized overheating associated with each of the three failure mechanisms illustrated in Figs 5-7.

However, development of this instrument followed a tortuous path because the technology employed is so sensitive and sophisticated that early versions of the instrument were subject to alarms from causes not related to component overheating. It took several years of intensive effort from several organizations to refine the design to a point where the equipment could be considered reliable.



1. Core overheating: Local, not yet serious

2. Core burning: Serious, but localized

3. Cracks developing in stator conductors

4. Loss of cooling caused seriously overheated stator winding

5-7. Unmonitored failures that generate high temperatures include cracking connection between coils (left), shorts between adjacent coils (center), and field coil/turn distortion (right)

How the GCM works

Operation of the GCM is based on the fact that thermal decomposition of organic materials—such as epoxy and polyester resins, enamel paint and core laminate enamel—produces large quantities of submicron particulates (pyrolysate products). Their size ranges from 0.001 to 0.01 microns. Under normal operating conditions, there are no particulates of this size in the cooling gas; they are produced only by the decomposition of organic materials.

Key components of the thermal monitor are an ion chamber detector, automatic sampling system, and electronics package. The ion chamber contains a weak alpha source. It produces negative ions which are carried into a collector assembly via piping across the generator ventilation fan.

The negative ions are attracted to a positive electrode in the ion chamber detector, producing a very small current flow. The current is amplified electronically to produce an output that typically is set at 80% of full scale on a monitoring device.

If there is no overheating within the generator, the output remains stable at the 80% base. But if overheating occurs, thermal decomposition will produce a large quantity of submicron particles which will be transported to the GCM via the generator's cooling gas system.

When the submicron particles enter the ion chamber detector, the negative ions attach themselves to these particles. Because the submicron particles are relatively heavy compared to the negative ions, the attached pair will likely flow past the positive electrode of the collector assembly, thereby decreasing the current and lowering the monitor output below the present 50% alarm level.

Overheating is verified by insertion of a confirmation filter at the inlet to the ion chamber. The confirmation filter will remove the submicron particles, allowing the ion-chamber-detector current to increase and cause the output to return to 80%—thereby confirming the presence of thermally generated submicron particles.

For the monitor to function reliably, the gas flow rate must remain constant and the ion chamber detector and electronics must be operating properly. The generator cooling gas fan essentially assures constant gas flow—unless a restriction occurs in the piping or rotor speed changes.

GCM evolution

In the mid 1960s, GE engineers designed an Ion Chamber Detector that could be used for the detection of particulates produced by the thermal decomposition of organic materials (Refs 1, 2). This device was later incorporated into a prototype instrument, the Core Monitor (CM), designed specifically for the early detection of local overheating in large hydrogen-cooled generators (Refs 3, 4). Several of these instruments were installed on generators at sites throughout the US.

Shortly after installation, a CM installed on a large generator indicated overheating was taking place. Because this was a prototype instrument, yet to be field-proven, a decision was made to disregard the alarm. Several days later the generator failed in service. Inspection revealed that severe core overheating had indeed occurred and that the monitor had provided an early warning.

This incident prompted GE to offer CMs as part of the supervisory equipment made available for turbine/generators. The OEM also signed a licensing agreement with Environment One Corp, Niskayuna, NY, allowing it to manufacture and sell the GCM.

Design improvements

The early monitors included a test particle source and a rotometer-type flow gage (Fig 8), in addition to the ion chamber detector, confirmation filter/solenoid assembly, and system electronics. In most installations, a signal alarm contact was connected to an annunciator in the control room.

When a signal was received, operators had to go to the physical location of the monitor—usually under the belly of the generator—and try to assess what caused the output reading to drop.

To eliminate the need for operators having to go to the monitor, a remote panel was developed that could be located in the control room. It provided operators with a recording of the output, operation of the confirmation filter, and operation of the test particle source used to test detector operation.

At the same time that the remote panel was developed, Westinghouse Electric Corp designed an automatic sampling system, which was incorporated into

Maughan on generators

This is the fourth article in a continuing series on generator monitoring, inspection, diagnostics, and root-cause failure analysis developed by Clyde V Maughan, president of Schenectady-based Maughan Generator Consultants, for the **CCJ**. The fifth article is in the queue and will be published in the 2011 Outage Handbook (May release).

The articles listed below, available at www.ccj-online.com/maughan/, are a valuable resource for owner/operators of turbine-driven generators:

- Maintaining carbon-brush collectors, 1Q/2010.
- Options for monitoring generator condition and their limitations, 2Q/2010.
- Input from monitoring, inspections, tests critical for maintenance planning, 3Q/2010.
- Generator condition monitor critical to avoiding catastrophic loss, 1Q/2011.
- Root-cause diagnostics of generator service failures, 2011 Outage Handbook.

the monitor. It provided a means for automatically collecting a sample of the thermally decomposed products when an alarm condition occurred. The sample then could be analyzed by a laboratory to confirm the validity of the alarm and, in some cases, determine the material that was overheating.

On generators where the hydrogen was not clean and dry, contaminants such as oil, rust, and scale could foul the piping and flow meter. When this occurred, hydrogen flow could be restricted, causing monitor output to drop. The resulting decrease in output signal caused an invalid alarm.

The flow-meter contamination problem was addressed by replacing that instrument with a differential-pressure gage. With this design change, the monitor output became much more stable, although fouling of the piping continued to be a concern.

The remaining issue with the early monitors, and the one of greatest concern, was determining when an alarm was valid. The next series of design improvements addressed this issue, and represented a major advancement in the level of reliability and confidence with this technology.

Specifically, an auto-alarm remote was designed to automatically and accurately verify when alarms were valid. It also indicated when (1) there was a fault with the monitor itself, (2) the supply power was interrupted, and (3) gas flow was too low. These changes, completed by the end of the 1980s, enabled the more reliable GCM (Ref 5, Fig 9).

The post-1989 GCM has had two additional improvements to enhance its reliability and performance. They are:

- The differential-pressure gage has been replaced by a differential-pressure transmitter. This improvement allows tracking of hydrogen flow remotely to determine the influence of flow on the output signal. Today's monitors also are designed for use in hazardous areas.
- The use of tagging compounds to help identify the location of overheating. Six different chemical compounds are mixed with the generator insulating paint. The formulations typically are applied (Fig 10) to the turbine end windings, collector end windings, core ID, rotor OD, bushings and lower leads and transformers and reactors (on GE Generex units).

Alarm conditions

There are four conditions that can cause monitor output to drop. They are:

- Decrease in gas flow.
- Faulty ion chamber detector.
- Faulty system electronics.
- Actual overheating within the generator.

The first three conditions will provide an invalid alarm, but mis-

8. Core monitor installation is of an early vintage

Environment One Corp

9. GCM and remote panel verify alarm validity interpretation of these erroneous signals essentially has been eliminated by the modifications described above. The fourth condition, actual overheating, is responsive to high temperatures associated with component failure anywhere within the generator. Typical failure modes that generate an alarm are breakdown of core iron lamination insulation, cracking of stator winding electrical connections, and winding shorts/grounds or broken turns in the field.

Another overheating mechanism which may cause an alarm is high local temperatures on the core clamping flanges, or on the copper flux shields used at the ends of the core by some generator manufacturers. As load conditions move toward leading power factor—starting at around 0.98 lag—the components at the ends of the core begin to generate additional eddy-current losses and may become hot (Fig 11).

In general, this condition is not harmful to the generator. But paint or contaminates, such as oil, on these components may overheat and form submicron particles that can alarm the monitor. Since alarms from this operating condition will only occur at higher power-factor loading, it is possible to screen out this type of false-positive alarm.

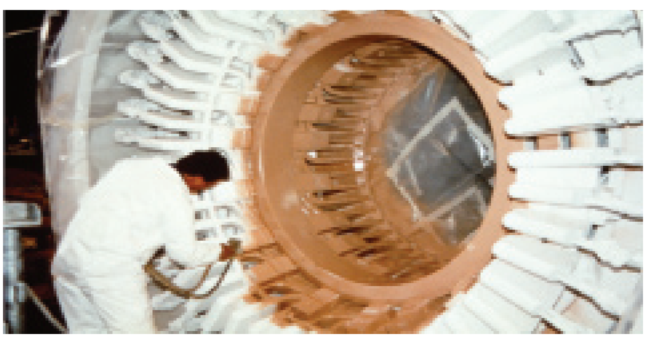
Operating experience

Early versions of the core monitor were relatively simple, with little signal-verification capability. These devices were viewed as somewhat of a glorified smoke detector, although recognized as much more sensitive and complex. If a valid signal were received, the device was capable of providing the expected alarm, and since the potential benefits were so great, more than 1000 were installed.

However, numerous drops in the output signals occurred as a result of invalid alarms from failures within the monitor, as well as from contaminants—such as normal oil vapor—and changes in gas flow through the monitor (Ref 6).

Oil contamination was plentiful, thus assuring numerous invalid alarms. The high costs associated with diagnosing an alarm quickly caused the monitor to loose credibility. Routine maintenance and operator also were neglected. Result: Early monitors were of little value to the plant operators and they often disregarded alarms.

Although the monitor had developed a dubious reputation, the industry's need for such a device motivated manufacturers to continue develop-



10. Tagging compound is applied to end winding

11. Burning of paint on a copper flux shield generally is not harmful to the generator but can initiate an alarm

ment work aimed at finding a reliable design. During the 25 years of this evolution, reliability gradually improved—as described earlier.

EPRI assisted in the development work by conducting an industry survey directed specifically at monitors produced after 1990. Immediate responses were received from 100 utilities, 29 of which reported having a total of 91 monitors in service. Here's a summary of the information gleaned from the survey:

- Quality of monitor maintenance—excellent, 6; adequate, 21; poor, 0.
- Quality of operator training—excellent, 2; adequate, 18; poor, 9.
- Experiencing of invalid alarms—yes, 2; no, 19. One utility reporting invalid alarms stated, "Some false alarms on all of our units, new and old." The other mentioned that the affected generator was 25 years old.

Overall, it appears that maintenance is adequate but training is not. The latter is particularly important because of the infrequency with which operating personnel experience alarms and because of the fundamental relationship between training and correct operator response to an alarm.

Survey respondents reported three additional incidents: two stated difficulties with gas-flow calibration because of high differential pressure across a multistage blower. The third said no alarm was received during a major rotor winding failure because of a clogged sensing line.

Three previously unreported "saves" were included in the comments received, specifically: (1) arcing caused by rotor winding failure, (2) burning from rotor shorted turns, and (3) alarm initiated by a break in an end winding connection.

Several additional comments provided by the respondents that may help guide your plant's monitoring efforts are these:

- Oil filters and traps are a must in sensor lines.
- Occasionally, non-critical alarms are caused by supply-voltage issues during plant startup.
- Difficulty in obtaining adequate gas flow through the monitor.

Operator training

Recommended steps for responding to an alarm are described in the manual provided with the monitor. The individual checks are not complicated, but alarms are likely to occur so infrequently that a control-room operator may not recall appropriate action to take when an alarm is received.

One solution: Configure the DCS to display a checklist of appropriated actions in either a textual or flowchart format to help the operator make a timely and logical response to the alarm. The monitor manual probably includes the information needed to implement this solution. If not, contact the instrument manufacturer.

Maintenance

Reliable GCM operation requires relatively simple periodic checks which are detailed in the installation and operations manual. The basics:

Daily. Observe gas flow rate and adjust if necessary. Verify that monitor output is at the 80% set point; recalibrate if necessary.

Weekly. Push the "Verification Filter Button" to confirm proper operation of the filter system.

Monthly. Perform relay, contact, keypad, output, and power tests.

Yearly. Check for hydrogen leaks from tubing, fittings, joints, and valve packing. Activate the "Auto Sampling System" to confirm proper operation.

Alarm successes

There are 20 incidents known to manufacturers of monitors where a valid alarm has resulted from the overheating of a generator component. Thumbnails of several incidents are provided below based on available information, which in some cases is limited. Root causes are many, including spontaneous core lamination insulation failure, field insulation failures, loss of cooling media, baffle rub, etc.

Rough estimates of repairs and repair costs avoided are included. Accuracy of the individual repair estimates is not high, but the estimates are presented to give a sense of the large potential saving associated with a properly functioning monitor. The combined potential saving from these 20 incidents is estimated at about $150 million.

Blockage of liquid hose. An alarm gave indications of slowly developing overheating. The unit was tripped and the inspection team found a stator-winding Teflon cooling-water hose was becoming blocked, causing overheating of two stator bars. Had failure occurred, it is likely that a double ground fault would have resulted in massive arcing and burning.

Worst-case repairs avoided: Full stator rewind, probable field rewind, possible core restacking, and extensive cleaning of the core, frame, and coolers.

Estimated repair cost avoided: $15 million.

Arcing of rotor winding. Several incidents of alarms resulting in shutdowns were attributed to winding faults.

Repairs avoided in each case: Possible arc damage to forgings with major impact on overall repairs.

Estimated repair cost avoided: Uncertain, but possibly significant (refer to Figs 5-7).

Phase connection failure. Alarm at full load automatically verified; reduced load by about 20% and alarm cleared; returned to full load and alarm returned as well. Inspection revealed burning of a failing phase connection. Major stator-winding failure prevented.

Repairs avoided: Full stator rewind, field rewind, extensive machine cleaning.

Estimated repair cost avoided: $10 million.

Intermittent alarm on high loads. Poor contact between several tube-to-copper connection resistors on gas-cooled stator bars caused a burn hole in a cooling duct.

Repairs avoided: Probably minor, but possibly stator winding failure.

Estimated repair cost avoided: $10 million.

Stator-winding water flow blockage. GCM alarmed on load increase. Inspection revealed blocked water flow, thereby preventing winding failure.

Repairs avoided: Probable stator rewind.

Estimated repair cost avoided: $10 million.

Stator core failure. GCM was in constant alarm for 30 minutes prior to stator-core meltdown. Intermittent alarms were occurring during the previous several months.

Potential for avoided repairs: Restack of core and stator rewind.

Estimated repair cost: Uncertain. If core repair had been possible prior to melt down, cost saving would have exceeded $15 million.

Operation without cooling water. GCM alarmed at 150 MW on a 650-MW generator while the unit was being ramped to full load. Alarm was disregarded temporarily, but unit was tripped manually at 250 MW. Inspection revealed that the hydrogen coolers were inoperative.

Repairs avoided: Possibly extensive damage to the generator.

Estimated repair cost avoided: Uncertain, but potentially very high.

Generator field ground. GCM alarmed about 40 minutes before manual trip of the generator. Inspection and test revealed that several rotor coils had elongated and caused multiple grounds to the retaining ring. The associated arcing had caused the alarm.

Repairs avoided: Possible fracture of a retaining ring with total destruction of the generator.

Estimated repair cost avoided: Tens of millions of dollars, plus exposure of plant personnel to severe injury.

OEM test protection. Use of GCM as protection against over-temperature during acceptance test detected a stator cooling-water blockage early and prevented serious damage. Prior tests without a GCM had resulted in over-temperature that destroyed an entire field.

Repairs avoided: Severe overheating damage to a field.

Estimated repair cost avoided: $3 million.

Core burning. GCM alarmed because of a 2-in. core-lamination hot spot which developed during normal operation.

Repairs avoided: Possibly eventual core meltdown.

Estimated repair cost avoided: Uncertain, but potentially extremely high.

Water cooler valved out. GCM detected overheating in a 550-MW generator while it was ramping up to full load following a generator rewind. The GCM was the first indicator that one of the water coolers was valved out.

Repairs avoided: Possibly overheating of the generator.

Estimated repair cost avoided: Uncertain, but potentially very high.

Baffle rub. During restart after stator replacement, the GCM alarmed. Inspection revealed a rub between the field and a gas flow restriction baffle. The GCM correctly identified the particulate matter as a valid alarm condition.

Repairs avoided: Minor.

Estimated repair cost avoided: Minor.

Breaking of stator winding connection. GCM alarmed on fracturing of a connection, allowing unit shut down without experiencing the extensive contamination normally associated with such a failure.

Repairs avoided: Severe contamination of the generator, possible stator rewind.

Estimated repair cost avoided: $5 million.

Field turn shorts. Existence of turn shorts was confirmed by monitor alarm, allowing a shutdown without collateral damage.

Repairs avoided: Probably small impact in overall repairs required.

Estimated repair cost avoided: Probably minor.

Failure to respond

There have been several reported incidents where after failure, review of plant records revealed that the GCM alarmed properly, but immediate corrective action was not taken.

Three of these incidents are presented below:

- **Core fault.** At a UK plant, a GCM alarm was given 30 minutes before the generator failed in service. Damage resulted from severe overheating caused by the failure to valve back in hydrogen coolers after a generator rewind.
- **Field-turn short**. A few months after a large generator field had been rewound, the GCM alarmed for 5 to 10 minutes and then cleared. Shortly thereafter high vibration required removal of the generator from service. Two turns in a small coil had shorted, thereby causing the pyrolysate particles which initiated the alarm, followed by bowing of the field, which produced the vibration (Ref 7).
- **Core meltdown.** GCM alarmed and less than an hour later the unit tripped on ground relay. Massive core meltdown had occurred, requiring a full core restack, full field rewind, and extensive cleaning of the frame and coolers. Cost exceeded $25 million.

Wrap-up

The GCM is an exceptionally sensitive device. Many years of development and design evolution were required before achieving a state of high reliability against incorrect alarms. That point appears to have been reached in about 1989.

The device monitors the generator for several adverse conditions that can initiate a valid alarm. These range from the benign to core meltdown—a spectrum from minor rub to complete generator internal destruction. Unfortunately, there normally will be at least some uncertainty as to the exact source and urgency of the condition initiating the GCM alarm. But since the costs associated with non-response can be exceedingly high, it is prudent to regard an alarm as valid unless known information confirms otherwise.

Also, because of the inherent nature of the failure modes being monitored, expeditious response may be very important. Thus it is advisable to configure the plant DCS to assist the operator in making a timely and correct response to an alarm. A properly maintained and operated GCM can mean the difference between a brief shutdown for minor repairs or a major overhaul involving weeks or months of costly downtime. CCJ

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1 G F Skala, "The ion chamber detector as a monitor of thermally produced particulates," Sixth International Conference on Condensation Nuclei, May 1966, Albany, NY

2 L P Grobel and C C Carson, "Overheating detector for gas-cooled electrical machines," US Patent 342 7880, 1969

3 C C Carson, S C Barton, and L P Grobel, "Immediate detection of overheating in gas-cooled electrical machines," IEEE Winter Power Meeting, January 1971, New York

4 S C Barton, C C Carson, R S Gill, W V Ligan, and J L Webb, "Implementation of pyrolysate analysis of materials employing tagging compounds to locate an overheated area in a generator," IEEE Power Engineering Society Meeting, July 1981

5 G F Skala, "The new generation condition monitor and its application to the protection of turbine generators," Proceedings of the First International Power Conference, 1986, Beijing

6 D J Wallis and S Kilmartin, "Can you believe your GCM?" Eighth EPRI Steam Turbine-Generator Annual Workshop and Vendor Exposition, August 2003, Nashville

7 David J Albright, "Rotor winding shorted turn detection with a generator condition monitor alarm," ASME Power, July 2008, Orlando

Clyde V Maughan is president of Maughan Generator Consultants, Schenectady, NY. He has more than 60 years of experience in the design, manufacture, inspection, failure root-cause diagnostics, and repair of generators rated up to 1400 MW from the leading suppliers in the US, Europe, and Japan. Maughan has been in private practice for the last 25 years. He spent the first 36 years of his professional career with General Electric Co.


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SPECIAL SECTION

2011 Conference & Exposition

April 4-6 • Manchester Grand Hyatt San Diego

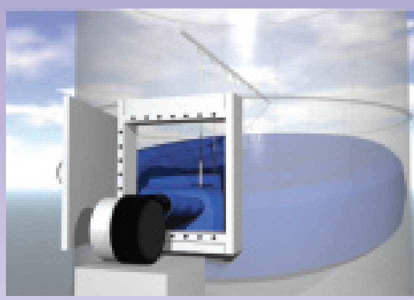
Participate in these Open Discussion Sessions

Heat Transfer Components
Tuesday, 8 a.m.

Water Treatment
Tuesday, 11 a.m.

Piping Systems
Tuesday, 3:30 p.m.

Controls
Ductwork, Dampers, Stacks
Wednesday, 8:15 a.m.



Contents

Valves
Supplementary Firing
Wednesday, 11 a.m.

Environmental Systems
Balance of Plant
Wednesday, 2:45 p.m.

Conference

All conference sessions are in Douglas Pavilion A

All receptions, meals, and the exposition are in Douglas Pavilion B, C, and D

Registration is in the Douglas Pavilion Foyer West

Monday, April 4

MORNING

7:00 to 8:00 Registration for the pre-conference seminar, "Combined-Cycle Outage Management." This event requires special registration

7:30 to 8:00 Light breakfast for pre-conference seminar registrants

8:00 to 9:00 **Outage planning and project management**
Bob Sansone, *The Power Generation & Construction Practice LLC*

9:00 to 9:30 Break

9:30 to 10:30 **HRSG retubing/module replacement**
Scott Wambeke, *HRST Inc*

10:30 to noon **Servicing electric generators**
Bill Moore, *National Electric Coil*

AFTERNOON

Noon to 9 pm Registration for conference delegates

Noon to 5 pm Exhibit set-up/exhibitor registration

Noon to 1 pm Luncheon for pre-conference seminar registrants

1:00 to 1:45 **Upgrading control valves using wireless technologies**
Jorgen Gertz, *Puffer-Sweiven*

1:45 to 2:00 Break

2:00 to 3:00 **Overhauling cooling towers**
Dave Staat, *GEA Power Cooling Inc*

3:00 to 4:00 **Servicing and testing of safety valves**
Robert Threlkeld, *Tenaska Inc*

4:00 to 4:30 **Overhauling steam turbines**
Mark Sherrill, *Turbine Generator Maintenance Inc*

4:30 to 5:00 **Condenser refurbishment**
Terry Quinn, *CTI Industries Inc*, and George Saxon Jr, *Conco Systems Inc*

EVENING

6:00 to 9:00 pm Official opening of the 2011 Conference & Exposition

Reception and dinner

Expo open

Tuesday, April 5

MORNING

7:00 to 6 pm Registration for conference delegates

Program

7:15 to 8:00	Breakfast
8:00 to Noon	Technical sessions
8:00 to 9:30	Open discussion: Heat-transfer components
9:30 to 10:00	Break
10:00 to 11:00	**Gas-side corrosion protection of HRSGs during layup** Cliff Cracauer, *Cortec Corp*
11:00 to Noon	Open discussion: Water treatment

AFTERNOON

Noon to 2:00	Luncheon **Expo open**
2:00 to 5:00	Technical sessions
2:00 to 3:00	**Management of P91 pipe in existing plants** Chris Bates, *New Harquahala Generating Co LLC*
3:00 to 3:30	Break
3:30 to 5:00	Open discussion: Piping systems
5:00 to 6:30	Reception **Expo open**

Wednesday, April 6

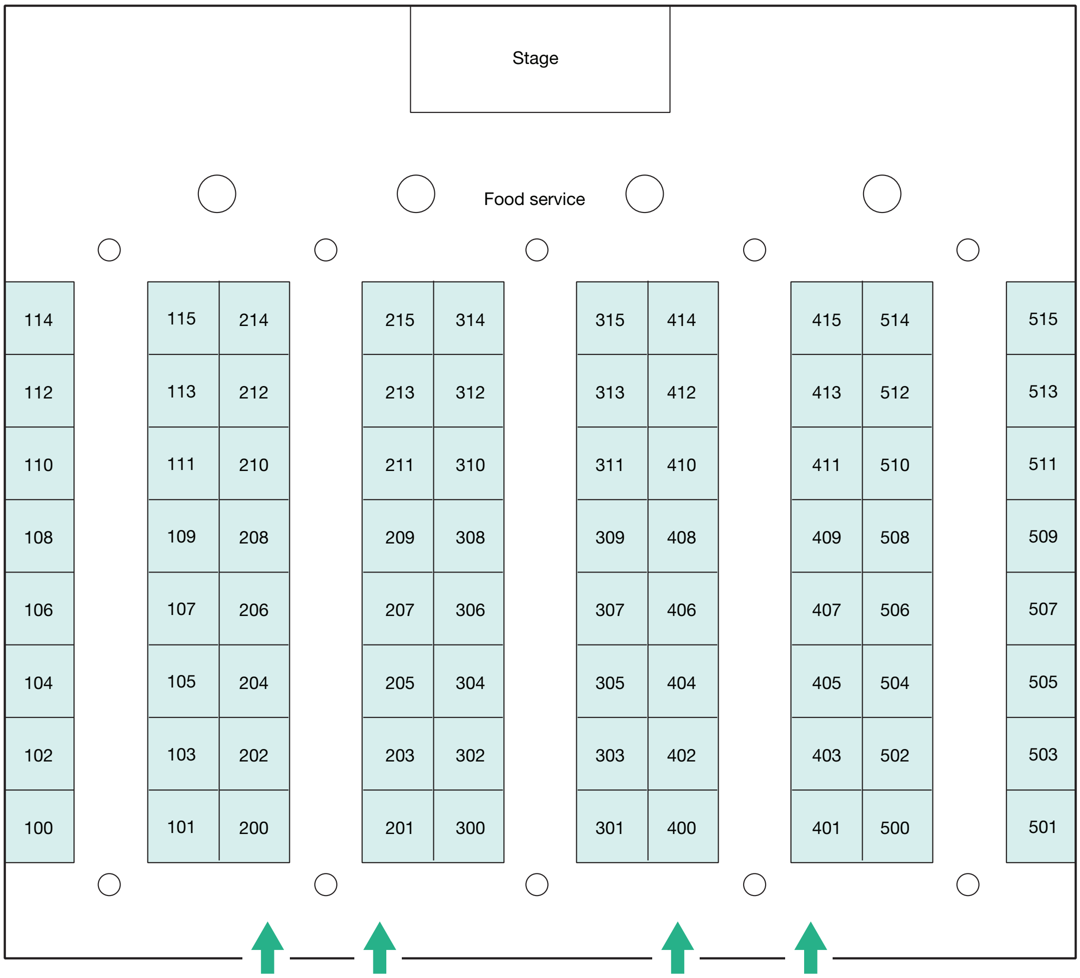
MORNING

7:00 to 1:30	Registration for conference delegates
7:15 to 8:00	Breakfast
8:00 to Noon	Technical sessions
8:00 to 8:15	Presentation of Steam-Plant Mentor Awards
8:15 to 9:30	Open discussion: Controls and structural components (ductwork, dampers, and stacks)
9:30 to 10:00	Break
10:00 to 11:00	**Stop leaking money through your valves** Michael Flaherty, *ValvTechnologies Inc*
11:00 to Noon	Open discussion: Valves, supplementary firing

AFTERNOON

Noon to 1:30	Luncheon **Expo open**
1:30 to 4:15	Technical sessions
1:30 to 2:30	**Improving the reliability and service life of HRSG expansion joints** Jake Sisson, *Dekomte*
2:30 to 2:45	Break
2:45 to 4:00	Open discussion: Environmental systems, balance of plant
4:00 to 4:15	Grand Prize drawing (users only; must be present to win)
4:15	Conference adjourns

Exposition Area



Exhibition Hall

Alphabetical Order by Company

Company	Booth #
Alimak Hek Inc	113
Alstom Power Inc	505
Automation Technology Inc	511
Babcock & Wilcox Co.	208
Bachmann Dampjoint Inc	103
BASF Catalysts LLC	110
Bremco Inc	203
Chanute Manufacturing	412
ChemTreat Inc	303
Clark-Reliance Corp	404
Cleaver-Brooks Inc	506
CMI Energy	402
CoaLogix	207
Coen Company Inc	211
Conax Buffalo Technologies Inc	109
Conco Systems Inc	210
Control Components Inc	513
Conval Inc	314
Cormetech Inc	410
Cortec Corp	302
Crane Co, Energy Flow Solutions	200
CTI Industries Inc	112
Dekomte du Temple	501
Donaldson Company Inc	407
EGC Enterprises Inc	105
EmeraChem LLC	503
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Fluidic Techniques	411
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GEA Power Cooling Inc	104
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Haldor Topsoe Inc	213
Hamworthy Peabody Combustion Inc	413
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Innovative Steam Technologies	306
ISOPur Fluid Technologies Inc	409
JASC-Jansen's Aircraft Systems Controls Inc	102
John Crane Mechanical Seals	212
Johnson Matthey	502

Company	Booth #
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Ludeca Inc	515
Margan Inc	107
Megawatt Machine Services LLC	509
Midwest Towers Inc	309
MOGAS Industries Inc	507
National Electric Coil	209
NEM USA Corp	300
Nooter/Eriksen Inc	415
Parker Hannifin Corp	202
PBV Valve	510
Peerless Mfg Co	408
Phoenix Turbine Services Inc	504
Piping Technology & Products Inc	512
Precision Iceblast Corp	405
Proton Energy Systems	100
Puretec Industrial Water	305
Quest-Tec Solutions	214
Revak Turbomachinery Services Inc	311
Scientech LLC	500
Sentry Equipment Corp	205
Severe Service Technology Inc	400
Siemens Energy Inc	304
South-Tek Systems	508
Stork H&E Turbo Blading Inc	111
Structural Integrity Associates Inc	406
TDC Filter Inc	106
Thermal Ceramics Inc	206
Thorpe Engineering & Construction Group	204
Titan Contracting & Leasing Inc	115
Tyco Flow Control	101
Valvtechnologies Inc	201
Vogt Power International Inc	215
Voith Turbo Inc	308
E H Wachs Co	310
Zeeco Inc	108

Exhibition Hall

Numercal Order by Booth Number

Booth #	Company
100	Proton Energy Systems
101	Tyco Flow Control
102	JASC-Jansen's Aircraft Systems Controls Inc
103	Bachmann Dampjoint Inc
104	GEA Power Cooling Inc
105	EGC Enterprises Inc
106	TDC Filter Inc
107	Margan Inc
108	Zeeco Inc
109	Conax Buffalo Technologies Inc
110	BASF Catalysts LLC
111	Stork H&E Turbo Blading Inc
112	CTI Industries Inc
113	Alimak Hek Inc
114	HRST Inc
115	Titan Contracting & Leasing Inc
200	Crane Co, Energy Flow Solutions
201	Valvtechnologies Inc
202	Parker Hannifin Corp
203	Bremco Inc
204	Thorpe Engineering & Construction Group
205	Sentry Equipment Corp
206	Thermal Ceramics Inc
207	CoaLogix
208	Babcock & Wilcox Co
209	National Electric Coil
210	Conco Systems Inc
211	Coen Company Inc
212	John Crane Mechanical Seals
213	Haldor Topsoe Inc
214	Quest-Tec Solutions
215	Vogt Power International Inc
300	NEM USA Corp
301	Environmental Alternatives Inc
302	Cortec Corp
303	ChemTreat Inc
304	Siemens Energy Inc
305	Puretec Industrial Water
306	Innovative Steam Technologies
307	Fuel Tech Inc
308	Voith Turbo Inc
309	Midwest Towers Inc
310	E H Wachs Co
311	Revak Turbomachinery Services Inc
312	Express Integrated Technologies LLC
313	Ice Solv LLC
314	Conval Inc
315	Emerson Process Management/Fisher
400	Severe Service Technology Inc
401	Holz Rubber Co
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HRSG Users Handbook a valuable resource

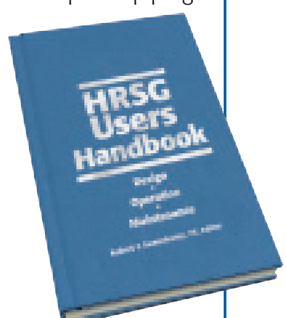
The knowledge base for proper design, operation, and maintenance of that special class of power boilers known as heat-recovery steam generators (HRSGs) essentially resides in the minds of a thousand or so engineers. Surprising as it may seem, relatively little generic information on the subject had been compiled in one volume until the *HRSG Users Handbook* was published five years ago this spring.

The 6 × 9 in. handbook, which contains more than 500 pages of valuable information on the design, operation, and maintenance of HRSGs, is a ready reference in hundreds of combined-cycle and cogeneration plants worldwide. Rarely a month passes that Editor Rob Swanekamp, a registered professional engineer with nearly two decades of hands-on powerplant management experience, doesn't receive at least one note on how the *HRSG Users Handbook* helped in solving a problem. What follows is a chapter-by-chapter summary of the book's content. For more information, and to order, visit www.hrsgusers.org.

Content easy to digest

Chapter 1. Operational safety.

2. **HRSG design,** with subchapters on writing specifications and on vertical and small boilers.
3. **Commissioning and initial startup,** including steam-system cleaning and initial performance testing.
4. **Steam system operation** has subchapters on best practices, steam bypass systems, duct burner operation, and attemperators.
5. **Performance monitoring** of the HRSG and of the steam turbine and condenser.
6. **Water treatment,** perhaps the most comprehensive chapter, has subsections on HRSG failure mechanisms, makeup water treatment, steam-cycle chemistry, HRSG layup, cooling-water treatment, and water-chemistry automation.
7. **Emissions control and CEMS.**
8. **Maintenance program development.**
9. **HRSG maintenance,** including standard practices, how to find and fix tube leaks, welding tube-to-header joints, NDE tools, special maintenance practices.
10. **Piping systems,** including the basics and special piping considerations.
11. **Valve maintenance.**
12. **Ductwork, dampers, and stacks.**
13. **Duct-burner maintenance.**
14. **Instrumentation and controls.**
15. **Plant staffing and organization.**
16. **Failure analysis.**
17. **Outage management.**



In addition, there are three handy appendices—including a directory of key industry suppliers and a glossary of acronyms and abbreviations.

Comparing ASME, European boiler codes and their impacts on design, operation

By S Hampson, D G Robertson, and **S Simandjuntak,** European Technology Development Ltd (UK)

In today's competitive electric generation marketplace more and more plants are cycling, which brings with it the likelihood of increased damage to power-plant equipment. For heat-recovery steam generators (HRSGs) serving in combined-cycle systems, low-cycle fatigue damage to thick-section components will accumulate as a result of large through-wall temperature gradients that develop during thermal transients.

The peak thermal stresses induced by high-temperature gradients in superheater-header and steam-drum walls are strongly influenced by the thickness of the components and the methods of operation during startup and shutdown. It seems obvious that design of the HRSG should include fatigue analysis of the critical components in order to determine the allowable number of operational cycles and acceptable limits for startup and shutdown ramp rates.

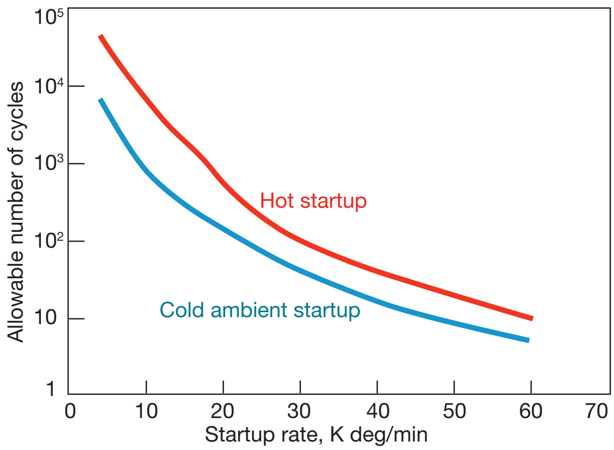
However, Section I of the *ASME Boiler and Pressure Vessel Code,* which provides rules governing the construction of power boilers, has no mandatory requirement for the designer to perform a fatigue analysis.

Regardless of the stress transients during startup and shutdown, ASME Section I only considers the steady-state operating conditions (specifically, the creep regime for superheaters) for the purpose of component thickness calculations. Some consideration of fatigue and creep-fatigue interaction is given in other sections of the ASME Code, but many boilers designed to ASME Section I may not have had an assessment of fatigue life.

By contrast, the European standard Euro Norm (EN) 12952-3 requires that a fatigue analysis be conducted when a boiler will be subject to cyclic operating conditions. Clearly, there is a fundamental difference between the requirements of ASME Section I and the European standard with regard to design of boilers for cyclic duty.

The authors recently completed cyclic-life capability studies for new HRSGs installed in two combined cycles. The studies included a review of HRSG component design features to identify any aspects that might constitute areas of weakness under cyclic operating conditions, as well as a fatigue-life assessment of key HRSG components to determine their capability for meeting the operational requirements specified by the plant operator.

The allowable numbers of load cycles to crack initiation were calculated for different temperature ramp rates using the EN 12952-3 methodology. Fig 1 shows some results for the connection of the saturated steam pipe to the HP drum.



1. Allowable numbers of load cycles to crack initiation are calculated for temperature ramp rates using EN 12952-3 methodology

Plant operators typically identify startups as cold, warm, and hot. They often are defined by the length of time the HRSG has been shut down. However, fatigue damage is known to be directly proportional to temperature changes. Thus another way of defining startups is by referring to temperature and/or pressure of the internal surface of the metal/component.

For the purposes of this discussion, a cold startup is characterized by a zero-pressure condition when the temperature of the steam-drum inside wall is 175F or less. A warm start is defined by an HP drum pressure of 45 to 75 psig when metal temperature at the surface of the inside wall is at least 285F (in HP drum). To be classified as a hot start, HP drum pressure must be at least 500 psig and metal temperature 465F.

When the metal temperature is at ambient (for example, in cold climates, the temperature could be around 40F and in warm climates around 100F) and the HRSG is starting with zero steam pressure, the startup event is called a cold ambient startup. This can be quite damaging in thick pressure parts like steam drums and superheater headers because of the large temperature gradients generated during the initial stages of startup when condensate heating occurs.

The fatigue analysis described by EN 12952-3 takes account of the thermal stresses arising from through-wall temperature gradients during cyclic operations. Note that thermal shocks caused by condensate quenching, which can be a significant issue for HRSGs with horizontal hot-gas paths, are not addressed by the Euro Norm.

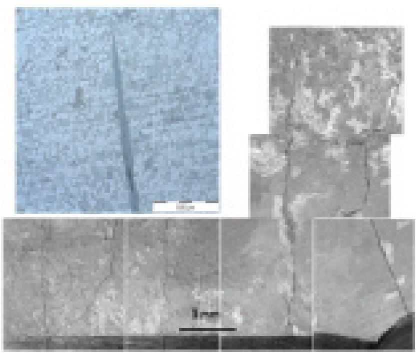
Superheater and reheater drainage

should be a key design point, if the risk of damage from condensate quenching is to be minimized. However, service experience has often shown that insufficient attention was paid to drainage at the design stage, and modifications to drain systems have been implemented following component cracking and failures caused by undrained condensate.

Condensate is formed in superheater tubes during cooling on shutdown, GT trip, and purge prior to warm/hot start. Condensate quenching is the thermal shock caused by condensate entering hot components, such as superheater headers. This phenomenon cannot be avoided by draining because the quench has already occurred by the time the condensate reaches the superheater drain.

Once formed, however, condensate should be removed to avoid the consequences of condensate migration through the system. The passage of condensate slugs, also known as condensate migration, is of particular concern because it can produce random transient cooling or quenching of tubes in particular tube bundles.

For a new plant, it requires the identification of the sources of such condensate and their elimination. This may dictate modifications to the plant, especially the number and location of condensate drains, and/or operating procedures. Studies have shown how temperature monitoring can be used to correlate condensate migration and quenching events with plant operational cycles.



2. Pattern of cracking on the internal surface of a drain pot for the HP superheater is indicative of thermal quenching. This supports the view that crack initiation was caused by condensate moving from the superheater module to the drain pot

In a recent study, cracking was found in the HP superheater outlet drain pot of an HRSG. The plant had operated mainly in base-load mode with occasional cycling. The damage had developed over a period of about three years, during which the plant had performed 50 two-shift cycles—that is, hot restarts.

The pattern of the cracking on the internal surface of the damaged component was indicative of thermal quenching (Fig 2), which supported the view that crack initiation was caused by condensate moving from the superheater module to the drain pot. Metallographic examination of the damage location showed transgranular cracks growing through the microstructure, indicating crack propagation by fatigue.

Findings. After completing fatigue analyses of critical HRSG components according to guidelines presented in EN 12952-3, the authors were able to establish acceptable limits for startup and shutdown rates in order to achieve specified numbers for cold, warm, hot operational cycles over the design life of the plant.

Where the desired numbers of different cycle types could not be achieved, then changes to operating procedures or modifications to component design were necessary. At the design stage, this frequently means that either the specified temperature ramp rates should be reduced or a stronger material should be selected in order to reduce the required component thickness and, hence, reduce the magnitude of thermal stresses during operational transients.

Also conducted was the application of fatigue analysis as part of root-cause failure analysis of a HRSG superheater drain pot, which had been damaged by thermal quench cracking. Fatigue calculations based on monitored temperature data showed that cracking could occur as a result of multiple quenching events that occurred during the two-shift cycles performed by the unit. Use of stronger material would improve the cyclic life of the component, but it was also necessary to identify measures that would reduce the severity of the thermal transients experienced during operational cycles. CCJ

References

1 European standard EN 12952-3, "Water tube boilers and auxiliary installations—Part 3: Design and calculation for pressure parts"
2 P Fontaine and J-F Galopin, "HRSG optimization for cycling duty based on EN 12952-3," Proceedings of the conference on cyclic operation of powerplants, European Technology Development Ltd, September 2007, London
3 M Pearson and R W Anderson, "Measurement of damaging thermal transients in F-class horizontal HRSGs," Proceedings of the international seminar on cyclic operation of heat-recovery steam generators, European Technology Development Ltd, September 2005, London
4 ASME Boiler and Pressure Vessel Code, Section II, Part D, "Materials properties"

Obtain, read latest version of ASME Code

The foregoing comparison of ASME Section I and European EN 12952-3 is instructive, but let's dig deeper to understand why things are the way they are regarding the ASME Code and what has been done to update Section I.

Robert W Anderson, the chairman of the HRSG User's Group, had the following to say in the "HRSG Users Handbook," edited by Robert C Swanekamp, PE, and published for the HRSG User's Group (go to www.hrsgusers.org for details) by PSI Media Inc, publisher of the COMBINED CYCLE Journal:

"Many purchasers of combined-cycle and cogeneration plants are under the impression that their specifications will be sufficient as long as they require compliance with the ASME Code. Unfortunately, they couldn't be more wrong—at least if they plan on cycling their HRSGs.

"The sole purpose of the ASME Code is to ensure safety—to prevent catastrophic failures and the resultant loss of life, injury, and property. It does an exceptional job of this. . . . But the ASME Code was never intended to be a 'design and construction handbook' that guarantees reliable and durable equipment fit for cycling HRSGs that will operate behind high-temperature GTs.

"These activities include the modeling of thermal transients, determination of component fatigue life, consideration of creep/fatigue interaction, location and configuration of dissimilar metal welds, effective management of condensate, implementation of effective desuperheater protective logic, and effective integration of major plant equipment.

"In addition to not mandating their execution, the Code gives little guidance regarding how to effectively perform these activities for the conditions experienced by today's HRSGs. The ASME is well aware of the shortcomings in its current Code and is working diligently to correct them."

That passage was written in 2006 and a couple of ETD's references have 2005 and 2007 dates. Progress is slow in the world of engineering standards and work on the ASME Code was ongoing while the references cited were written.

Note that Section I of the 2007 edition of the Code includes Part PHRSG, "Requirements for Heat Recovery Steam Generators." It cites requirements for superheater and reheater condensate removal systems designed to minimize thermal shock and prolong the lifetime of pressure parts. It also specifies rules for desuperheater drain pots and provides sketches of drain arrangements. Owner/operators should review the latest version of the Code before preparing specifications for new HRSGs.

Air attemperation protects HRSGs against damage at low loads

Most owner/operators of gas-turbine-based generating assets—combined cycle and cogeneration—are painfully aware of the beating their heat-recovery steam generators take in cycling service. Until recently, most HRSGs were designed for base-load service because that's the way the plants were *supposed* to operate. If you need proof that this generally is not the case, read "Changing duty cycles. . ." on p 12.

In today's competitive generation market, operating flexibility and ancillary services are what the grid operator generally is willing to pay a premium for; kilowatt-hours are "table stakes" in many areas of the country. And this operating paradigm is unlikely to change given the increasing need for fast-start GT assets to back up intermittent renewables (www.integrating-renewables.org).

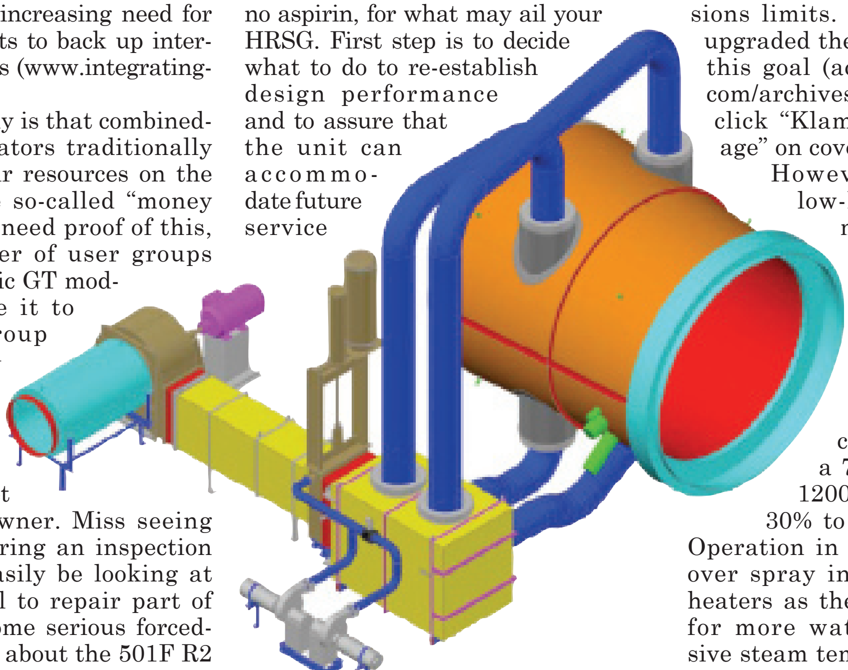
Also noteworthy is that combined-cycle owner/operators traditionally have focused their resources on the gas turbine—the so-called "money machine." If you need proof of this, count the number of user groups focusing on specific GT models and compare it to the one user group addressing HRSG concerns.

Gas turbines certainly deserve the attention they get from the asset owner. Miss seeing a blade crack during an inspection and you could easily be looking at a $10-million bill to repair part of the rotor, plus some serious forced-outage time (read about the 501F R2 issue at http://combinedcyclejournal.wordpress.com).

By contrast, a few million dollars can buy years worth of weld repairs for your HRSG. Plus, a tube failure is unlikely to cause much, if any, collateral damage and unlikely to dictate an immediate shutdown. No wonder HRSGs often don't get the respect they deserve; steam turbines neither.

The years have taken their toll on HRSGs and steamers. It's only recently that many plants installed during the bubble of 1999-2005 have been taking a hard look beyond the gas turbine. Wear and tear and, in some cases, poor operating practices have caused cracking of piping downstream of attemperators, "spaghetti" tubes in high-temperature harps, severely fouled tubes in LP and economizer heat-transfer sections, etc. Performance has suffered and owner/operators must take corrective to remain competitive.

What to do? There's no quick fix, no aspirin, for what may ail your HRSG. First step is to decide what to do to re-establish design performance and to assure that the unit can accommodate future service demands. A proper course of action cannot be charted without a thorough inspection of both the gas side and water side and investigation of the root causes of any problems uncovered.



1. **Outside air fan,** powered by a 150-250-hp VFD motor, forces air into the GT exhaust gas stream just ahead of the HRSG inlet duct via four nominal 24-in.-diam pipes. Small fans supply sealing air to the damper

Many plants are challenged by the need to operate at low loads to avoid overnight shutdowns and the cycling damage they inflict on major equipment and plant thermal networks. A goal you often hear at user group meetings for a 2 × 1 combined cycle is having the ability to remove one GT from service late in the day and operate the other at 50% of its rated output, allowing the steamer to remain synchronized at low load. This, of course, depends on the capability of the GT to operate at low load within permitted emissions limits. Several owners have upgraded their turbines to achieve this goal (access www.ccj-online.com/archives.html, click 3Q/2009, click "Klamath gets better with age" on cover).

However, users may find low-load operation detrimental to the health of their HRSGs. Reason is that for some gas turbines—such as the popular GE 7FA—exhaust temperature increases at low loads. Specifically, the exhaust from a 7FA can be as high as 1200F at loads from about 30% to 70% of rated output. Operation in this range can cause over spray in interstage desuperheaters as the control system calls for more water to reduce excessive steam temperature. Over spray is conducive to fatigue damage in large-bore piping downstream of the desuperheaters if the pipe undergoes a large, sudden temperature drop associated with the over-spray event.

It is difficult to prevent over spray

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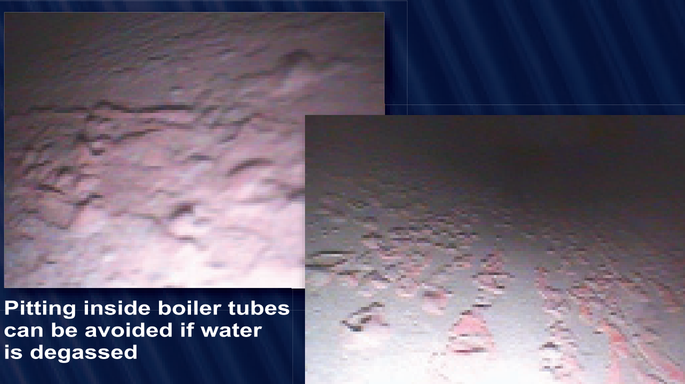

Pitting inside boiler tubes can be avoided if water is degassed

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HRSG XIX

The annual conference and exposition of the HRSG User's Group is perhaps the largest gathering in the world of major owner/operators affiliated with the combined-cycle/cogeneration sector of the electric power industry. It traditionally draws about 350 participants; many are plant managers and heads of O&M departments.

The organization has matured, since its inception in 1993, from a handful of powerplant managers discussing elementary problems like "gage glass leaks" to a globally recognized professional association of more than 1500 members in 50 plus countries committed to pushing back the boundaries of HRSG technology.

Chairman Bob Anderson and Communications Director Rob Swanekamp say, "We're fortunate in that we continue to expand and increase our service offerings to a growing global community of HRSG users." Key to that success, Chairman Anderson points out, is the true collaboration the group fosters among users, manufacturers, and service providers. All conference and workshop sessions are open to all three to provide the broadest possible perspective and experience base.

Swanekamp reminds that the organization was founded with the focused goal of helping members solve problems associated with the steam-cycle portion of GT-based combined-cycle and cogeneration facilities. CCJ

in some HRSG designs. The control system signals attemperators to quickly reduce steam to its saturation temperature, thereby causing unevaporated water to enter the steam pipe. The water quenches the pipe and initiates thermally induced low-cycle fatigue. Should this phenomenon occur frequently—defined as less than 1000 cycles—fatigue failure of superheater and reheater components is likely. This puts a 10-yr lifetime on critical system components for a plant that cycles 100 times annually.

Also keep in mind that 1200F exhaust gas causes oxidation and creep damage to HRSG inlet-duct non-pressure-parts—such as flow distribution plates, duct liners, tube ties, etc.

Forget the water, use air

The engineers at HRST Inc, Eden Prairie, Minn, known worldwide for their HRSG engineering know-how, had seen enough over-spray damage at the hundreds of plants they inspect regularly and came up with the idea of air attemperation to minimize the need for water to control steam temperature.

Analysis Manager Amy Sieben, HRST's thought leader on air attemperation, told the editors that the idea is relatively simple: Inject significant amounts of ambient air into the transition duct between the gas turbine and the HRSG inlet duct to reduce the temperature of the exhaust stream entering the boiler. The amount of air flowing into the system is adjusted to maintain a specific range of superheat for both main and reheat steam.

The temperature of the air/exhaust gas mixture is set to maintain metal temperatures in the HRSG and steam turbine, and the interconnecting piping, within a "safe" range without having to use water for attemperation.

2. First install of QuenchMaster™ allows owner to operate its 7FAs down to 90 MW. Before air attemperation, the GTs could not operate below 110 MW

When the GT achieves 80% of its rated output, control of final steam temperature reverts to the spray-water attemperators better suited for service at near design conditions.

QuenchMaster™ is the name of the patent-pending system enhancement. Don't confuse this with HRST's recently announced economizer upgrade, ShockMaster™, designed to prevent tube cracking and other issues caused by damaging thermal gradients (access www.ccj-online.com/archives.html, click 4Q/2009, click "Shock resistant economizer" on the cover.

The air injection system is simple in design, and modular, for quick installation. Main components are main air fan, ductwork, damper, damper seal-air fans, piping, and controls (Fig 1). Construction time is about three weeks for foundation and setting of equipment; tie-in can be completed within a week.

Sieben recommended a front-end cycling study for each prospective customer to determine the system's applicability and benefits given the plant's configuration and operating paradigm. She said this takes about six weeks to plan and execute because dispatch coordination is required. Lead time on equipment is about 12 weeks.

HRST did CFD and performance modeling on its first commercial installation—a 3 × 1 7FA-powered combined cycle—and nearly pinpoint design accuracy was verified by field measurements. The first application "worked right out of the box." Sieben said she didn't think CFD analysis generally was necessary for follow-on projects.

The plant that installed the first QuenchMaster is owned by a major utility (Fig 2). The editors did not have permission to attribute the following information on the installation without completing the company's review process, which was not possible by press time. Here are the basic facts as the editors understand them:

QuenchMaster is programmed into the plant's DCS as a permanent part of the facility's operation. It is used during every startup from the time each GT reaches 20 MW until it achieves 140 MW. Before air attemperation was installed, the GTs couldn't operate below 110 MW because of balance-of-plant equipment limitations.

Specifically, the boiler-feed pumps were maxed out (100% of rated speed) providing water for desuperheaters and inlet-duct water sprays, as well for maintaining drum levels. Note that the wasteful practice of spraying high-quality water directly into the exhaust gas stream also was tearing up the inlet duct liner. At 110 MW before QuenchMaster, the reheat attemperator was open to 45% and the main steam attemperator to 80%.

With air attemperation, the turbine can operate down to 90 MW with the feedpumps at 45% speed, the reheat attemperator closed, and the main-steam attemperator open only 15%. The wear and tear on pumps and spray-water control valves is reduced dramatically.

Long-term the benefits of QuenchMaster are potentially far more significant. Sieben estimated that the service life of main-steam piping—located about 80 ft above grade at this plant—may be three times as long with air attemperation than without. Experience at similar plants spraying to saturation, she continued, indicates you can expect failures within 10 years of service.

Regarding the lifetime of harps, failure to prevent moisture ingress means virtually instant failure of tubes receiving water. Therefore, eliminating over spray prevents it as a cause of tube failure. Of course, you can still get water ingress from leaking control valves, failure of the control system to stop attemperation on a trip, and buildup of condensate. CCJ

CHP facilities dominate

The prolonged turndown in the US economy suffocated construction of new generating plants in 2010. Electricity suppliers had spent the previous two years convincing themselves things weren't as bad as they seemed and that a rebound was overdue. By the time 2010 rolled around, they were pretty well convinced there was little demand for new capacity and the construction pipeline all but dried up. The first two articles in this issue ("By the Numbers") illustrate just how tough things were, and continue to be.

Thus there were relatively few large-scale power projects entering service last year that might qualify as Pacesetter Plants as defined by the editors. In fact, just slightly more than 6000 MW of gas-turbine-based generation began operating in 2010 and half that was peaking capacity. Simply put, last year was the worst year in terms of new capacity additions since before the bubble, which began in 1999.

So it shouldn't come as a surprise that CHP facilities funded by universities and government would get most of the recognition for innovation in the power sector. The pathway to public and institutional financing of power projects is long and torturous. It takes years—often more than a decade—to get the support required. But once funded, these projects usually continue to move forward—poor economy or not.

Stony Brook. The only utility generating facility recognized as a 2010 Pacesetter was Massachusetts Municipal Electric Co's Stony Brook Energy Center—for maintaining plant value through technological

1. Stony Brook Energy Center. Glenn Corbiere, operations supervisor; Karl Winkler, plant manager; David Ela, maintenance supervisor; and Stephen Quesnel, technical services supervisor (l to r)

2. ICS, an Emerson Process Management company. Back row: David Karcher, production manager/systems designer; Parke Brown, project manager; Jeff Garrison, engineering technician; and Lorcan Roche, VP/engineering manager. Front row: Stephan Paszkowski, CAD drafter; Beena Chatterji, controls engineer; Beshoy Sawriss, field engineer; Patrick Nolan, president; and Paul Vasilak, senior controls engineer (l to r)

3. Cornell Combined Heat and Power Plant. Project Manager Tim Peer, PE (center) is encircled by Vicki Davis, project coordinator; Frank Perry, associate project manager; W S (Lanny) Joyce, PE, project executive; Brian Wanck, project engineer; and Diane Gardner, project administration (clockwise from bottom)

4. Bay View Combined Cycle Cogeneration Facility. Martin F Ellman, PE, project manager for Middough Inc, the engineer for the project; Michael Schreidah, PE, project manager for the City of Toledo; Rick Bullard, contract manager for Solar Turbines MMS, the plant operator; and Mike Kemp, project manager for HCS Group (l to r)

2010 Pacesetter Plants

5. Middough Inc's Bay View project team. Back row: Paul Granata, David Gross, Ralph Dybiec, Ken Lauer, Dilup Tudu, Bill Shivak, Dan Loreta, and Gerry Kuminski. Front row: Mike Groff, Don Huller, Jennifer Closs, Wayne Powell, Marty Ellman, Steve Simpkins, Tom Healey, Bob Knight, and George Brown (l to r)

upgrades to address changing market conditions. Spend a day at this well-maintained facility with Plant Manager Karl Winkler and his staff and you come to appreciate the work done since COD three decades ago to keep the plant competitive in the New England generation market (Fig 1).

Most recently, Stony Brook replaced its legacy controls with a modern PLC-based system to assure the operational flexibility and reliability required to meet today's demanding grid requirements for the supply of ancillary services. Critical to achieving this objective was the work done by Innovative Control Systems Inc (ICS), Clifton Park, NY, which was acquired by Emerson Process Management as the controls upgrade project was in its final stages (Fig 2).

Details on Stony Brook and the other 2010 Pacesetter Award recipients are available at www.ccj-online.com/archives.html. Articles on Stony Brook, the Cornell Combined Heat and Power Plant, and Oregon State University Energy Center are accessible by clicking 2Q/2010; those on the Orange County Cogeneration Plant and the Bay View Combined Cycle Cogeneration Facility by clicking 3Q/2010.

Cornell. Project Manager Tim Peer, PE, and his very capable engineering and administrative staff were recognized for transforming the university's bootstrapped, decades-old steam supply system into a full-service utility (Fig 3). Coal-fired boilers

6. Victoria Ludwig of EPA's Landfill Methane Outreach Program presents the City of Toledo's Michael Schreidah, project manager for Bay View, the LMOP's Project of the Year Award the day before he accepted the COMBINED CYCLE Journal's Pacesetter Plant Award. Middough's Marty Ellman, the City of Toledo's George Robinson, Middough's Gabe Sciarretti, and Solar Turbines' Marv Richardson and Bernie Pfeifer look on (l to r)

7. Orange County Cogeneration Plant. Ray Diego, plant operating engineer (1); Scott Bice, plant HVAC mechanic (2); Gus Fischer, manager of facilities (3); Barbara Tidball, senior project manager (4); Jason Asch, plant electrician (5); Dennis Seasock, plant craft supervisor II (6); Phil Cook, manager of facilities operations (7); Rick Sanchez, plant craft supervisor I (8); Tim Corbett, plant administrative manager II (9); Joseph Edwards, manager of facilities and real estate (10); and Randy Vanny, project administrative manager II (11)

were replaced with a gas-turbine-powered cogen system, large-scale energy-conservation and emissions-reduction solutions were implemented, and the reliability of the campus electric distribution system much improved by a complete overhaul of electrical infrastructure.

Bay View was, perhaps, an even more ambitious project than Cornell because it required a leap in faith in some of the technology employed. In brief, Mike Schreidah, PE, project manager for Toledo's Div of Water Reclamation, led the development of a state-of-the-art combined-cycle plant capable of burning landfill, digester, and natural gases alone or in any combination to reduce the city's carbon footprint and to provide a cost-effective highly reliable source of power for critical water-treatment facilities (Fig 4).

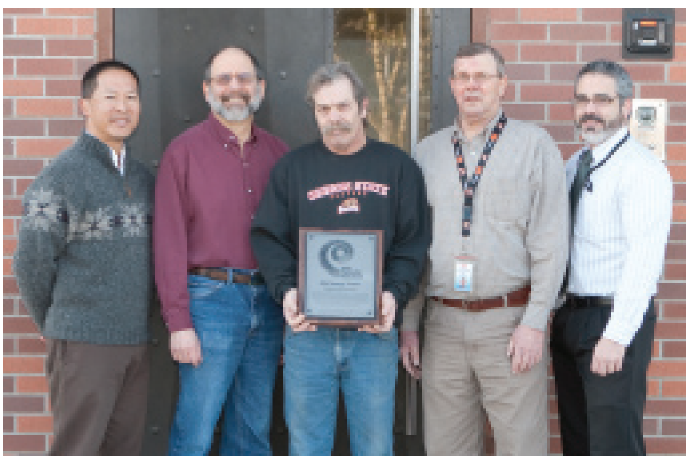
Keep in mind that the technology for removal of problematic siloxanes from landfill gas had virtually no commercial experience when Bay View was designed. And the idea of burning multiple fuels, including two green gases, alone or in combination in both the gas turbine and heat-recovery steam generator (supplementary firing), was simply a "dream" in the minds of many industry professionals.

Schreidah put together a blue-ribbon project team. Middough Inc, well known in "small power" was the engineer, while Solar Turbines Inc supplied the gas turbine and Rentech Boiler Systems Inc provided the heat-recovery steam generator (HRSG). Solar, assisted by HCS Group Inc regarding the handling and treatment of landfill gas, also manages the combined-cycle plant's O&M.

Project managers were Marty Ellman, PE, for Middough, Marv Richardson for Solar, Cory Goings, PE, for Rentech, and Mike Kemp for HCS Group (Fig 5). Rick Bullard is Solar's contract manager for plant O&M; he has experience burning landfill gas in conventional boilers.

The Toledo project was visible on many industry radar screens. Bay View accepted the Project of the Year award from Victoria Ludwig of EPA's Landfill Methane Outreach Program the day before Schreidah received the COMBINED CYCLE Journal's 2010 Pacesetter Plant Award (Fig 6). Previously, the Northern Ohio Chapter of the Assn of Energy Engineers had recognized Bay View for innovation in the design of cogeneration and renewable-energy projects.

Orange County received the **CCJ's** pacesetter award for reducing both emissions and the cost of energy while improving the reliability of electrical and thermal energy supply to Santa Ana's Civic Center Campus. Further, the cogeneration project cited was a catalyst for conservation



8. OSU Energy Center. Henry Alaman, associate director of site operations; Larrie Easterly, university engineering manager and project manager; Les Walton, energy operations supervisor; Steve McKinney, maintenance and energy operations manager; and Vincent Martorello, director of facilities (l to r)

9. Solar Turbines Inc provided the gas turbines for all four CHP projects recognized as 2010 Pacesetter Plants. Project Managers Wayne Leland (Cornell), Jim Boguslaw (Oregon State), and Marv Richardson (Bay View) share the spotlight (l to r) upgrades to government office buildings consistent with LEED initiatives.

Were there an award for perseverance, Orange County would have won that hands down. Gus Fisher (No. 3 in Fig 7), manager of facilities operations for the county, was a young engineer in the mid 1980s when he and colleagues at Central Utility Facility first proposed building a cogeneration plant to serve the surrounding campus.

Oregon State. Larrie Easterly, the project manager for the OSU Energy Center, and the university's engineering manager, guided design and construction of the new facility, which looks more like a research lab than a powerplant, start to finish (Fig 8).

The award reads: "For replacing an antiquated central plant with a combined-cycle energy center designed to the highest LEED standards. Green features include rainwater harvesting for boiler makeup, energy recovery for domestic hot water and space heating, passive ventilation, natural lighting, and the ability to burn biodiesel and methane in both the gas turbine and HRSG to support university research."

Solar and Rentech received special recognition from the editors for designing and supplying gas turbines and HRSGs to meet the individual needs of all four CHP plants receiving the 2010 Pacesetter Plant Award (Figs 9 and 10). Characteristics of the steam and electric generating equipment include operational flexibility, high efficiency, low emissions, high reliability, and the capability to burn conventional fuel as as well as landfill gas, digester gas, biodiesel, and methane. CCJ

10. Rentech Boiler Systems Inc. Kevin Slepicka, senior sales engineer, and Project Manager Cory Goings, PE (right) played major roles in the design and installation of the heat-recovery steam generators for all four CHP projects cited as 2010 Pacesetter Plants

ABMA elects Rentz chairman

Jack Rentz, PE, president, Rentech Boiler Systems Inc, was elected chairman of the American Boiler Manufacturers Assn (ABMA) during the group's annual meeting in mid January. Also elected for two-year terms were Vice Chairman Kevin Hoey, president, AESYS Technologies LLC, and Secretary/Treasurer Tom Giaier, president, Detroit Stoker Co.

ABMA, based in Vienna, Va, is the national non-profit trade association of commercial, institutional, industrial, heat-recovery, and electricity-generating boiler and combustion equipment manufacturers. Contact President Randy Rawson for more information (randy@abma.com, 703-356-7172).

The three officers identified above and the following two members of the ABMA's Board of Directors were appointed to the association's Executive Committee:

- Scott Lewis, Chanute Manufacturing Co, a unit of Optimus Industries LLC.
- Jeff Shallcross, Nationwide Boiler Inc.

Lewis is the organization's immediate past chairman and Shallcross chairs the ABMA Associate Members Group.

Finally, these three industry executives were elected to the ABMA Board of Directors for a three-year term:

- Nancy Stephenson, director, Cormetech Inc.
- Terry, president, Ajax Boiler.
- Bob Stemen, president, Applied Heat Recovery LLC.

Rentz is the founder, president, and CEO of Rentech, well known to CCJ's readers for its heat-recovery steam generators installed in many CHP systems. The company also is respected for its wide variety of custom-designed industrial boilers, which typically are used in the refining and chemical industries. Rentz is a co-founder of both Rentech Boiler Services Inc and Frontier Welded Products Inc.

He was introduced to the ASME *Boiler and Pressure Vessel Code* and shop operations as a part-time employee of Lubbock Manufacturing Co during his senior year at Texas Tech Univ. After graduation, Rentz moved to Abilene to work for ABCO Industries Inc, a small boiler company. He was named president in 1992. Four years later he left ABCO (now defunct) to start Rentech, which today employs more than 250 persons, including 21 engineers.

Rentech is the fastest-growing boiler manufacturer in America, with offices in Lincoln, Neb; Tulsa, Okla; and Sacramento, Calif. All manufacturing is done at the company's Abilene facilities, which recently were expanded to provide more than 100,000 ft^2 of shop space.

Industry leaders Scarborough, Lesch retire

Dan Scarborough called it a second career, retiring from NAES Corp at the end of last December after 16 years of service to the company—the final 10½ years as VP of powerplant operations and technical services. He joined NACE in November 1994 after retiring from the US Navy. For details on Scarborough's NAES career, access *Energy Line,* November/December 2010, at www.naes.com/energy-line.

Joe Lesch, long a contributor to the COMBINED CYCLE Journal, retired as a VP of Chromalloy at the end of January after 27 years of service. He was particularly well known in the industry among members of the Western Turbine Users Inc and a supporter of that organization since before it incorporated more than 20 years ago. Lesch worked as an engi-

Scarborough

Lesch

2012 BEST PRACTICES Awards

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

Categories: Management, O&M, Safety, Design, Environmental
Deadline for entry: December 30, 2011

Judging/recognition: All entries will receive industry recognition by way of a profile in a special editorial section on Best Practices published in the Q1/2012 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 30, 2011 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:
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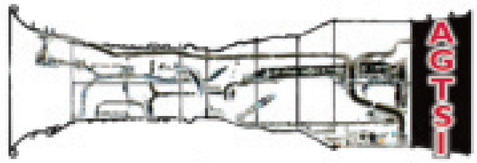
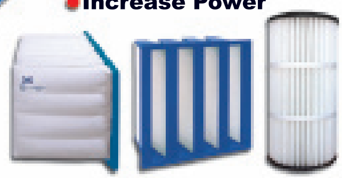




neer for more than four decades and was involved in the gas-turbine business for 36 years.

Eight bells: Jon McCall

William Jonathan (Jon) McCall, a CRO at the Arlington Valley Energy Facility, located about 40 miles west of Phoenix, died suddenly last fall. He is remembered by colleagues as upbeat person with a dedicated work ethic. McCall, who left a wife of 18 years and two young children, received numerous certifications over the years—including ones in water plant operations, asbestos inspection and management, radiation protection, and hazardous materials handling.

McCall

Shortly before his death, McCall and his Arlington colleagues developed a heat-stress caution and warning alarm which was submitted by the plant for a 2011 Best Practices Award (details on p 49).

Company news

General Physics Corp, Elkridge, Md, presents Kansas City Power & Light Co's Hawthorn Generating Station with its 2010 Power Performance Excellence Award for achieving a 3% heat-rate improvement at Unit 5. Senior VP Joe Nasal, Energy Services, said teamwork and the use of GP's EtaPRO™ and VirtualPlant™ performance technologies enabled Unit 5 to achieve a record 9900 Btu/kWh and reduce CO_2 emissions by 150,000 tons.

Emerson Process Management, Pittsburgh, acquires Turbine Control Service Associates Inc, also Pittsburgh, an independent provider of generator excitation control systems.

Sentry Equipment Corp, Oconomowoc, Wis, acquires Waters Equipment, a division of Neptune Chemical Pump Co. The addition of Waters is expected to significantly expand Sentry's global portfolio of steam and water sampling products.

GE Power & Water signs an expanded licensing agreement with Deb Mukhopadhyay, developer of the HERO™ process, to help more of its customers increase water-use efficiency. HERO is a critical component in some zero liquid discharge systems.

HPI LLC, Houston, announces the acquisition of UK-based DLE Aero Ltd, which specializes in DLE/DLN mapping, to help users minimize emissions and increase combustion efficiency. HPI supplies turbine control, fuel-valve replacement, and mechanical overhaul services.

Gas Turbine Efficiency, Orlando, Fla, agrees to sell substantially all of its technology and intellectual property for non-core aviation engine wash services to Pratt & Whitney. Following the sale, the company reported, it would continue to focus on the power generation and oil and gas industry sectors.

IST, Cambridge, Ont, Canada, honors the Guaracahi Combined Cycle Plant, Santa Cruz, Bolivia, with its fourth annual Plant of the Year Award. The facility's once-through heat-recovery steam generators (OTSGs) are equipped with an air dilution system allowing them to run dry at elevated GT exhaust temperatures while meeting stringent noise restrictions.

Johnson Matthey's Power Plant Industries Group, Redwitz, Germany, launches www.powerplantcatalysts.com to aggregate technical and sales data for SCR technology vital to this industry sector. The multilingual site initially will provide information in English and German; Chinese in the near future.

MYR Group Inc, Rolling Meadows, Ill, a specialty electrical contractor, executes a contract with Great Basin Transmission LLC, an affiliate of LS Power, to construct the 235-mi, 500-kV One Nevada Transmission line from Ely to Las Vegas. The line will carry approximately 600 MW, allowing access to renewable resources in northern and eastern Nevada and connecting NV Energy's northern and southern grids. The utility plans to own 25% of the line and to purchase Great Basin's share of the capacity under a long-term agreement.

Alstom's smart grid demonstration project is selected for federal funding. It is designed to integrate distributed energy resources into the electric grid, helping DOE achieve a 20% reduction in peak demand nationally by 2030. Other goals of the government program are 100% availability to service critical loads 24/7, a 40% improvement in system efficiency, and 20% of the nation's capacity produced by distributed and renewable energy sources.

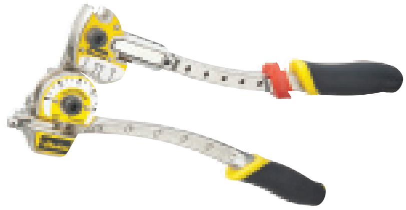
Wood Group GTS, Houston, receives an $875-million EPC contract from Israel's Dorad Energy Ltd for Israel's largest private power station, the 12-unit, 800-MW Dorad Power Plant, scheduled for first service in 36 months.

Products/services update

ESCO Tool, Holliston, Mass., offers a new air-powered, right-angle portable welding end-prep tool with a improved clamping mechanism that allows for easy entry and removal from the boiler tube. It is ideal for end-prepping single waterwall tubes

in tight spaces, requiring only 1.5 in. of radial clearance. Titanium nitride-coated cutter blades can prep high-chrome-content tubes from ½ in. ID to 2¼ in. OD.

Parker Hannifin Corp's Instrumentation Products Div has assembled a comprehensive package of tools for small-bore tube assembly—including benders, a cutter, deburrer, sawing vise with integral hacksaw guide,



and an inspection gauge. It includes everything necessary to install tube fittings—both CPI™ and A-LOK®—in various system applications. Access "Tube Fabricating Equipment," Parker Catalog 4290, at www.parker.com.

Heat Trace Products LLC, Leominster, Mass., announces a self-regulating heat cable system for virtually any process temperature maintenance and freeze-protection application. Standard lengths: 5, 10, 20, 50, 100, and 200 ft. Heating cables can main-

tain temperatures up to 150F and will not burn-out if overlapped.

Clark-Reliance Corp, Strongsville, Ohio, announces enhancements to its direct-reading Simpliport® that make the water level gage easy to view from virtually any angle or distance. The product meets ASME Code Section I requirements. Optics provide bright red and green indication of steam and water level.

Mettler-Toledo Thornton Inc, Bedford, Mass, introduces the Model M800 multi-parameter transmitter for monitoring water purity in power generation and other applications. The instrument was developed for applications where precise measurement of conductivity/resistivity, pH, dissolved oxygen, flow, and temperature of ultrapure water are critical.

Olympus NDT, Waltham, Mass, introduces the IPLEX YS, which comes with a 98-ft-long insertion tube and can operate on ac or battery power. It can connect to a local compressed-air source or to CO_2 cylinders for completely tether-free operation.

General Physics Corp, Elkridge, Md, expands the capability of its EtaPRO™ product to include advanced pattern recognition modeling in addition to thermal modeling. APR models can correlate historical data from multiple sensors as a "system." For example, such a system of sensors around a boiler feed pump may have more than 40 sensors and include bearing temperatures and vibration data in addition to capacity and efficiency performance parameters. APR returns an expected range of normal operation based on the values of all the sensors in the system.

Alimak Hek Inc, Houston, provides elevators for combined-cycle plants to facilitate transport of personnel and tools safely to the highest elevations on heat-recovery steam generators. A typical installation might have three landings and a capacity of 3000 lb.

Mee Industries Inc, Irwindale, Calif, announces seal-flushed pumps for extended seal life in fogging applications. Pumps are designed for continuous-duty service on demineralized water with virtually no maintenance and high efficiency. Flushed pumps feature a specially ported inlet manifold enabling a tap-water internal flush to lubricate and cool the seals.

People/appointments

HRST Inc, Eden Prairie, Minn, promotes Victor Ferris to president. He will concentrate on day-to-day management, allowing CEO Bob Krowech to focus on R&D. Ferris joined the company in October.

Aviation, Power & Marine, Boynton Beach, Fla, names Melody Manning director of industrial gas-turbine sales. She will focus on parts for large frame engines. Manning was VP sales for Houston-based Turbine Energy Solutions, which closed.

NAES Corp, Issaquah, Wash, reports Butch Kimbrell has joined the company as VP construction and Bob DeNeve as VP business development. Kimbrell has over 30 years of experience in a wide range of industrial construction activities with companies such as Stone & Webster, Halliburton, and Brown & Root; DeNeve comes from SNC Lavalin Engineers & Constructors.