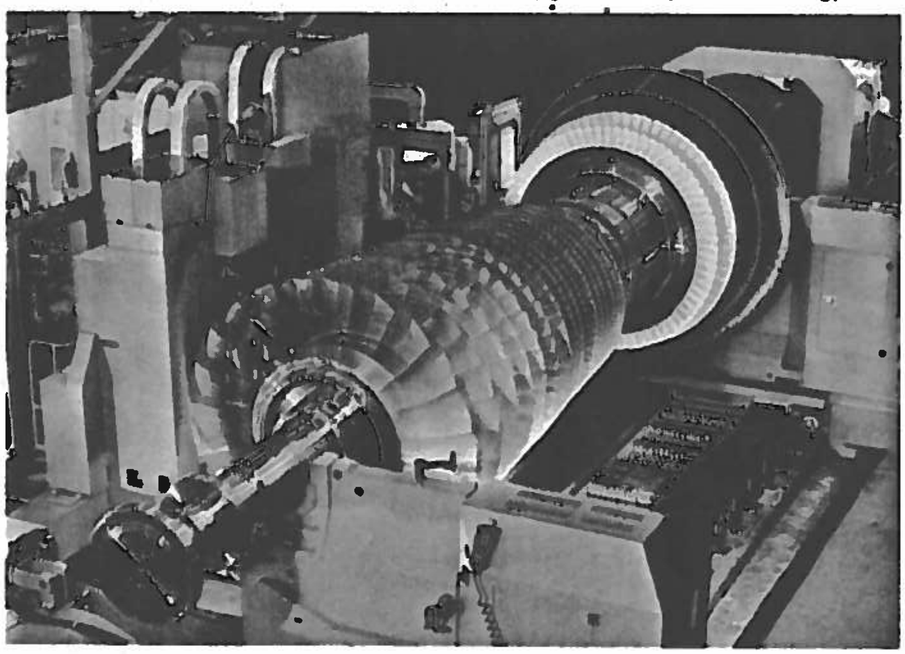
Siemens Releases "Shaping Power" Option for Renewables Integration

The need for flexible power generation has increased drastically over the past few years, particularly when integrating renewables. Another driver is seasonal peaks in demand that have become more severe as global drought conditions have reduced hydropower production. One option for addressing this need is the Siemens Energy SGT6-5000F with Shaping Power. It offers the familiar gas turbine reoptimized for increased output and higher efficiency during hot weather and for improved operating flexibility at part-load conditions.

By Bonnie Marini, PhD, Siemens Energy

Slow and stable plant operation, once the norm, no longer meets the needs of the modern integrated and extremely dynamic grid. New generation must be fast and flexible while remaining robust and reliable even under very demanding operating conditions. Gas turbines have always provided very flexible operations compared with other utility-scale generation choices, such as coal. The Siemens SGT6-5000F gas turbine with Shaping Power option is well-positioned to be the technology choice for the 21st-century electricity grid that demands faster and more flexible response, without an efficiency penalty (Figure 1).

1. Responding with flexibility. Siemens' Shaping Power option offers improved operating flexibility with its SGT6-5000F gas turbine. The turbine was redesigned to provide fast-ramping capability that will meet the needs of a dynamic electricity grid. *Courtesy: Siemens Energy*



Modern Grid Problems

In the past, gas turbines operated as baseload units, or for peaking power supply for short periods. Baseload units ran at maximum power for extended periods. Peakers were expected to cycle frequently in order to supply additional power when demand increased. A regional power grid in the U.S. might be supplied by a combination of nuclear, coal, wind, and gas-fired generation, with gas ramping on and off or up and down for peaks in demand during the day. An example of daily grid demand and the sources of electricity supply is shown in Figure 2.

The need for fluctuating power supplies, even with this traditional fuel mix, is immediately apparent because the familiar baseload power generation plants were not designed for fast load change following. In response to that need, more flexibility has been introduced into fuel-efficient gas turbine combined cycles over the past few years. Integrated cycles are available with control logic allowing the plant to quickly ramp up and down, reducing startup emissions and startup costs. For example, the Siemens' Flex-Plant combined cycle series, first introduced in the mid-2000s, improved the efficiency of power generation and increased operating flexibility while reducing the environmental footprint of gas-powered generation.

In recent years, the need for operations flexibility has increased drastically. The introduction of significant amounts of renewable generation created a situation where the fluctuations in demand are not the only driver for the need to change the amount of power supplied by gas-fired generation. The introduction of a significant amount of renewable generation resulted in rapid fluctuations in supply power that must be quickly balanced with quick-acting, and often very expensive, generating sources (Figure 3). While demand is fluctuating during the day, the supply from renewables has a strong influence on the shape of fossil-fired plant response, particularly during off-peak hours.

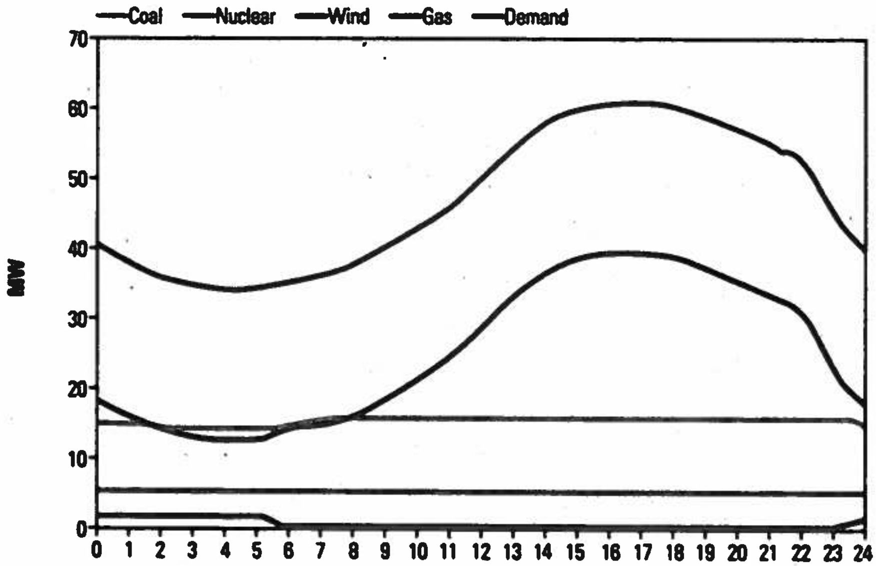
Renewables, such as wind and solar, are not typically dispatchable generation. Once installed, the operating cost of renewable generation is low, so there is the desire by grid operators to dispatch renewables whenever possible. In some regions, renewables are usually dispatched first, either by utility policy or because renewable generation has the lowest market bid price.

When renewable generation was a small percentage of the electricity supply to the grid, small simple-cycle gas turbines were used as renewable backup. Today, the amount of renewable energy on the grid in some regions is very large, and therefore the need for flexible power has grown. In some regions with large renewable portfolios, ramp rate demands as high as 400 MW/min are required to backstop fluctuating renewable generation. One seldom-used approach is to manage the renewable dispatch to meet existing system response limitations. The more common approach is to use larger gas turbines, usually in combined cycles, that can move in concert with renewable electricity production.

What is Shaping Power?

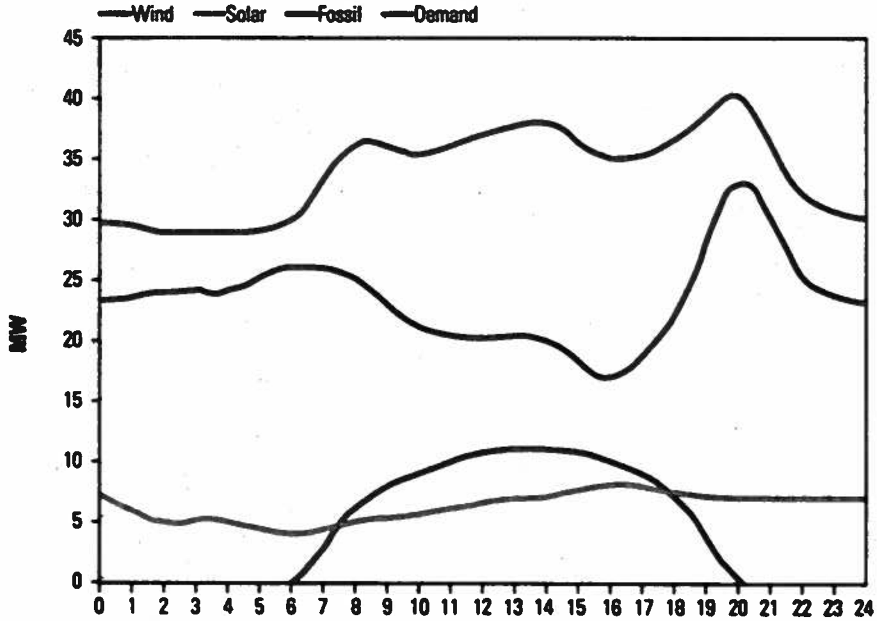
The principle behind the design of Shaping Power was to design a combined cycle plant that complements renewable generation rather than clashing with it. The challenge for the designers was to improve the turbine efficiency and power output at part and full load, unlike other familiar power increase processes (see sidebar). These goals challenged designers to conquer the common problem with all gas turbines: Power production drops as ambient temperatures rise. Shaping Power gives the plant owner the option to quickly ramp up or ramp down power quickly, without impact on the life expectancy of turbine components, even at high ambient temperatures.

2. The historical grid. Typical supply and demand curves over a 24-hour day for a traditional grid with a low renewable contribution. *Source: California ISO*



Gas turbines use ambient air as their working fluid. The amount of air a turbine ingests is controlled by the volume of the engine and the density of the air. On a hot day, a fixed-size turbine will ingest less air mass than on a cold day because the air is less dense. Gas turbine compressors have a maximum flow capability and have some adjustability. Some compressors are adjusted by one row of airfoils that open and close, somewhat like window blinds, changing the amount of air that gets through. Making

3. The modern grid. Typical supply and demand curves over a 24-hour day for a modern grid with significant renewable generation. *Source: California ISO*



large adjustments in flow with one row of airfoils results in a decrease in efficiency due to the step change in volume across the row.

Historically, compressors were designed for an operating point near ISO (standard) conditions, and the adjustability was used to ramp up and down. Many newer engines have multiple rows of adjustable airfoils. Using multiple rows allows the change in volume to happen gradually and reduces the efficiency change when the airfoils are closed or opened. Multiple rows of adjustment are used to ramp up and down and improve part-load efficiency. If the efficiency is not changed significantly when the flow is changed, this offers the opportunity to add more range without sacrificing efficiency.

The Shaping Power design adds the advantage of a larger compressor to the flexibility offered by multiple rows of variable compressor airfoils to extend the operating range of the turbine. From the optimized baseload design point, the engine can quickly ramp down by closing the variable airfoils and quickly ramp up by using the additional mass flow through the oversized compressor.

This design is an improvement for two specific reasons. First, Shaping Power is a feature that adds generation in excess of the baseload power the engine produces, even when ambient temperatures rise. This characteristic is advantageous whether there are renewables on the grid or not. The second unique advantage is that significant amounts of power can be quickly and predictably ramped in and out to support the grid when renewables are cycling. In a combined cycle, the plant can be operating before ramping in Shaping Power. The response is quick because the bottoming cycle is already warm and the steam turbine will automatically follow the gas turbine. The result is a quick-responding gas turbine that then produces a fast-responding combined cycle.

The Shaping Power option available on the SGT6-5000F has a turndown that is less than 40% of baseload while remaining in compliance with standard emissions regulations. This package design gives operators the opportunity to go from the lowest turndown point to full Shaping Power at a ramp rate of 30 MW/min per turbine, thus enabling more than 400 MW of ramping capacity from one SGT6-5000F 2 x 1 Flex-Plant at a rate in excess of 60 MW/min. Siemens offers the SGT6-5000F with Shaping Power in all of the Flex-Plant configurations.

How Does Shaping Power Work?

The SGT6-5000F with Shaping Power option begins with the base SGT6-5000F but with an increase in compressor capacity, as discussed above. The turbine runs at the same operating

More Options for Increasing Gas Turbine Power

Shaping Power uses an oversized compressor to supply the full mass flow throughput of the gas turbine at a larger range of ambient temperatures to produce peaking power and to maintain part-load efficiency. Standard gas turbines have adjustable inlet vanes to change mass flow through the compressor, which are used when ramping the engine up and down. Some gas turbines have more than one row of adjustable inlet vanes to control the air flow into the compressor without significantly reducing engine efficiency.

Manufacturers offer a variety of equipment additions that can produce more electricity from a particular gas turbine. All these options have advantages and, sometimes, major disadvantages. Here are some examples.

Peak the Turbine. This approach increases the turbine inlet temperature, not the turbine mass flow. The downside of this approach is that the increased temperature reduces the service life of gas turbine hot parts. Because Shaping Power makes more power by increasing the mass flow through the turbine and not by increasing operating temperature, service life is not reduced.

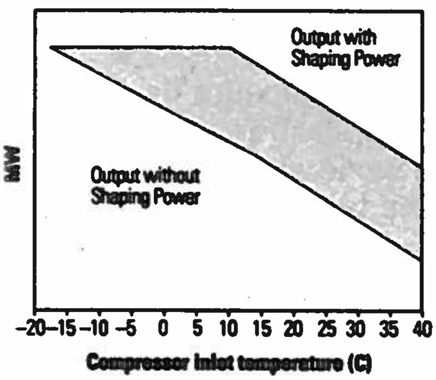
Chill the Inlet Air. Another option is to add a chiller and coil to cool the inlet air, fooling the turbine into believing it's a cool day. Cooler air is more dense, therefore more air mass flow moves through the turbine, increasing the power production. This option works well and can be installed upstream of any gas turbine. The downside of this technology is cost and the significant auxiliary load to run the chiller, reducing plant efficiency.

Cool the Inlet Air. A similar option is to use evaporative cooling to cool the air entering the gas turbine. The moisture addition cools the air. This option works well in regions with low to moderate ambient humidity, but this system uses significant quantities of purified water.

Inject Steam. Steam power augmentation is also an option. This technology injects steam into either the compressor or the combustor, or both, again providing more mass through the turbine. The downside is obvious: A continuous supply of very clean steam is required.

Duct Fire the Exhaust. Another popular option is duct firing the gas turbine exhaust gas to raise its temperature before it enters the steam generator. This option does not impact the gas turbine but does increase steam production and therefore increases power generation from the bottoming cycle. Duct-firing systems are fairly low in capital cost, but the cycle efficiency decreases when used. Another downside is increased plant fuel consumption.

4. Less temperature sensitivity. The SGT6-5000F with Shaping Power will produce more power for a given ambient temperature. *Source: Siemens Energy*



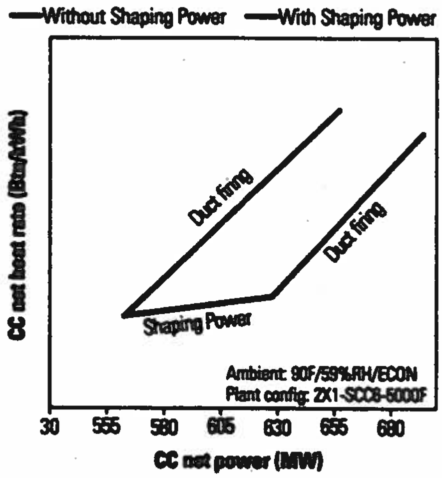
temperature as the base variant, so Shaping Power has no impact on service life. Shaping Power works much like duct firing on a combined cycle. Duct firing supplements the exhaust energy to produce more steam by the heat recovery steam generator. The additional steam produced can then be used to produce full load from the steam turbine, even when the gas turbine is at part load. With Shaping Power, the same process takes place, but it's the untapped capacity of the gas turbine that is leveraged.

The advantages of Shaping Power grow when temperatures rise. On a hot day, the gas turbine has less flow than it is capable of using. Shaping Power increases this mass flow to fully exploit the unused gas turbine capability (Figure 4). This capability enables a variety of new applications. For example, on a given day, the grid operator can choose how much power to produce. The engine can operate anywhere in the gray region of Figure 4 without any change in operating temperature, and therefore without change in emission levels. The turbine can also operate below the lower line in part-load operation. With an SGT6-5000F, the engine can also operate at levels of less than 40% load in standard emissions compliance, so the range of output available is substantial.

In combined cycle mode with duct firing active, the capability of Shaping Power is clear: User-specified power is produced at a lower heat rate from the same bottoming cycle (Figure 5). From another perspective, Shaping Power moves the optimum design point to a point lower than the maximum power output of the engine. The difference is that the unit with Shaping Power has about 10% more power capability when operating at its highest efficiency.

In some regions of the U.S. with a large portion of renewable generation, gas-fired plants are tasked with filling in the voids when renewables generation fluctuates. If

5. Improved efficiency. Shaping Power produces a given amount of power at a lower heat rate in a duct-fired combined cycle. *Source: Siemens Energy*



your combined cycle is a Flex-Plant with gas turbines configured with Shaping Power, then you have the option to run the plant at part load and keep the remaining capacity as spinning reserve. In the Electric Reliability Council of Texas, this capability is called an ancillary service and has a market value.

The spinning reserve option has much economic value because an SGT6-5000F with Shaping Power reaches optimum efficiency at about 10% below maximum engine load. This extra 10% can be ramped in on demand to compensate for the unexpectedly lost renewable generation. In effect, an SGT6-5000F with Shaping Power functions like a high-efficiency combined cycle with a small peaker unit built in.

Shaping Power Status

All Siemens 60-Hz gas turbine designs go through full-load validation testing at Siemens' full-scale engine test facility in Berlin. The SGT6-5000F with Shaping Power was tested from 2007 to 2010 before market introduction in early 2011. This configuration was tested for more than 395 engine operating hours and 1,500 engine starts. The hot gas path is common with the standard SGT6-5000F that entered commercial service in 2009. To date, 24 SGT6-5000F engines with Shaping Power have been ordered, and the first unit is scheduled to begin commercial operation in 2012. The SGT6-5000F with Shaping Power is being manufactured at Siemens' expanded manufacturing facility in Charlotte, N.C. ■

*—**Bonnie Marini, PhD** (bonnie.marini@siemens.com) is director, 60-Hz product line marketing for Siemens Energy.*

Gas Turbine Makers Gear to Flexibility Needs with New Models

Competition among gas turbine makers heated up this September as Alstom unveiled its upgraded GT24 gas turbine and corresponding 60 Hz KA24 combined cycle power plant, while Mitsubishi Heavy Industries (MHI) introduced the M701F5 gas turbine—a 50 Hz F-class gas turbine upgrade.

An Upgraded GT24

Alstom's upgraded product launches came on the heels of its upgraded GT26 gas turbine and corresponding KA26 combined cycle power plant for the 50 Hz electricity markets in June. The French company introduced the original GT24 gas turbine 15 years ago, and even in the early days it was recognized for "exceptional operational flexibility, high part-load efficiency, and fast start-up capabilities," Alstom says in a technical paper. "From the very beginning this gas turbine technology incorporated features such as multiple variable compressor guide vanes and sequential combustion, which set a new industry standard regarding operational flexibility."

The upgraded turbines were designed around a heightened need for high operational flexibility, a trend that is expected to continue. "While demand will continue to vary greatly, the growing portion of renewable sources of electricity production are expected to require combined cycle plants to be more and more used to levelize the overall production of electricity in many power markets," the technical paper says.

Just five years ago, combined-cycle power plant specification requirements focused on the highest baseload efficiency based on about 8,000 operating hours per year and the lowest specific sales price. Today's combined cycle power plant must be based on the highest overall weighted efficiency based on expected operating hours and load regime, and the lowest cost of electricity based on both baseload and part-load profiles.

The next-generation GT24 is capable of delivering 230 MW at 40% efficiency (with a heat rate of 8,571 Btu/kWh), the company claims. The KA24 combined cycle plant can achieve 700 MW output in a 2 x 1 configuration, and when fully optimized, it achieves more than 60% gross efficiency. The plant also features a spinning reserve for delivering more than an additional 450 MW in 10 minutes in low-load to baseload settings. The full upgrade package has been implemented in the grid-connected GT26 Test Power Plant in Birr, Switzerland (Figure 1). Alstom plans to manufacture key plant components of the upgraded gas turbine at its factory in Chattanooga, Tenn.

1. A notch above. Alstom in September launched an upgraded GT24 gas turbine and corresponding KA24 combined cycle power plant for 60 Hz electricity markets. The turbine was tested at Alstom's grid-connected GT26 Test Power Plant in Birr, Switzerland. *Courtesy: Alstom*

A New Generation F-Class Turbine

Later in September, MHI announced its own newly upgraded and more flexible gas turbine design. The F-class M701F5 will operate at a turbine inlet temperature of 1,500C—a level only reached by G-class or higher turbines, MHI said.

The M701F5 gas turbine achieves a rated simple cycle power output of near 350 MW (ISO basis) and 520 MW in combined cycle power generation. It is designed around the preceding M701F4 and leverages experience with MHI's F-class fleet, which has 182 units in operation around the globe, with more than 7 million actual operating hours.

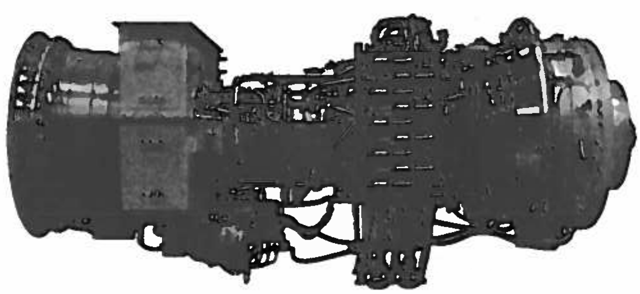
The compressor section retains the M701F4's airflow, but mid- and rear-stage profiles have been modified from NACA1 to CDA2. MHI also said that the combustion system is based on the verified GAC engine, and the turbine section incorporates turbine technologies developed for the J Class, including advanced cooling technology and advanced thermal barrier coatings.

Small But Flexible Turbine

Also in September, GE launched its FlexAero LM6000-PH (Figure 2), a highly efficient 50-MW gas turbine that couples flexibility and efficiency, reaches full power in just five minutes, and uses no water. GE—which introduced the 510-MW FlexEfficiency 50 Combined Cycle Power Plant in May (see "GE Develops FlexEfficiency 50 for Increased Operational Flexibility," p. 90) and claims it has already received more than $1 billion in orders for its aeroderivative and heavy-duty gas turbines this year—also said the FlexAero was launched to meet fast-changing power generation needs.

The company's customer base has rapidly changed and expanded to include industrial businesses and remote communities, Darryl Wilson, president and CEO of GE's aeroderivative gas turbine business said. "We developed the FlexAero to give those customers advanced technology, leading in flexibility and efficiency, which can be shipped and installed faster than

2. Light and lithe. Following the launch of its 510-MW FlexEfficiency 50 Combined Cycle Power Plant in May, GE in September added the 50-MW FlexAero LM6000-PH to its FlexEfficiency portfolio. *Courtesy: GE*



any technology in its class and can operate independent from the power grid."

- GE additionally claims that the turbine, operating in a combined cycle, can reach an efficiency above 80% through cogeneration.

A key feature of the turbine is that it uses GE's innovative DLE2.0 technology, which reduces NO_x emissions to just 15 ppm without the need for water. The technology allows customers to save more than 26 million gallons of water per turbine, per year, which is typically used to dilute CO and NO_x emissions in a gas turbine, GE said.

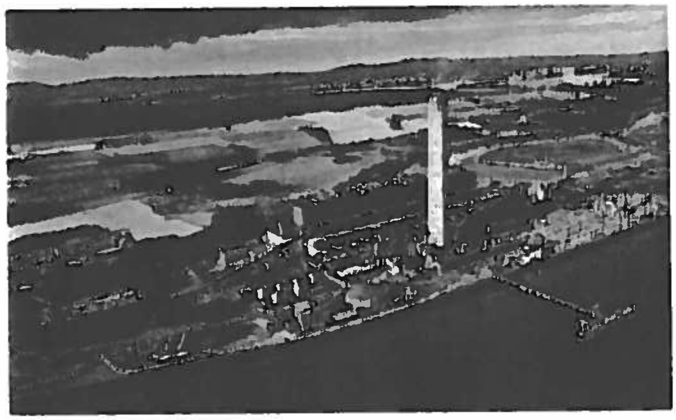
"Today, 30 percent of the world's population is water constrained. By 2025, the number will reach 60 percent," said Steve Bolze, president and CEO of GE Power & Water. "As global energy demand increases, so does the stress on our water supply—a reality that we take very seriously when we develop new technologies across our portfolio."

UK Pulls Funding for Flagship Longannet CCS Demonstration

Ditching the only project remaining in its £1 billion ($1.60 billion) carbon capture and storage (CCS) competition, the UK government declined to back the much-watched CCS project at the Longannet power station in Fife, Scotland, in October. The decision balances the UK's low-carbon ambition with the need to ensure that taxpayer money is invested in "the most effective way," the nation's Department of Energy and Climate Change said. The funds are now expected be used to "pursue other projects" in both Scotland and England.

The 2,400-MW Longannet Power Station, owned by ScottishPower, is the third-largest coal-fired power station in Europe (Figure 3). The CCS project being built by a consortium comprising ScottishPower, UK grid operator National Grid, and oil company Shell sought to demonstrate post-combustion technology using an amine solvent to remove carbon dioxide from flue gas. The project would also have demonstrated carbon transport and storage—National Grid had planned a new carbon dioxide pipeline from the power station at Longannet to its existing pipeline

3. Taking the Longannet view. The UK declined to back a flagship carbon capture and storage demonstration project that would have seen more than 20 million metric tons of carbon dioxide captured from the 2,400-MW coal-fired Longannet power plant in Fife (shown here) and pumped under the North Sea. *Courtesy: ScottishPower*



The T-Point Plant: The Ultimate Validation Test

Fourteen years ago, the MHI T-Point demonstration combined-cycle plant in Takasago, Japan, changed the way modern gas turbines are validated under real operating conditions. In February, T-Point marked yet another milestone by starting to validate the world's largest and highest efficiency gas turbine, which operates at the unprecedented turbine inlet temperature of 1,600C.

By Angela Neville, JD

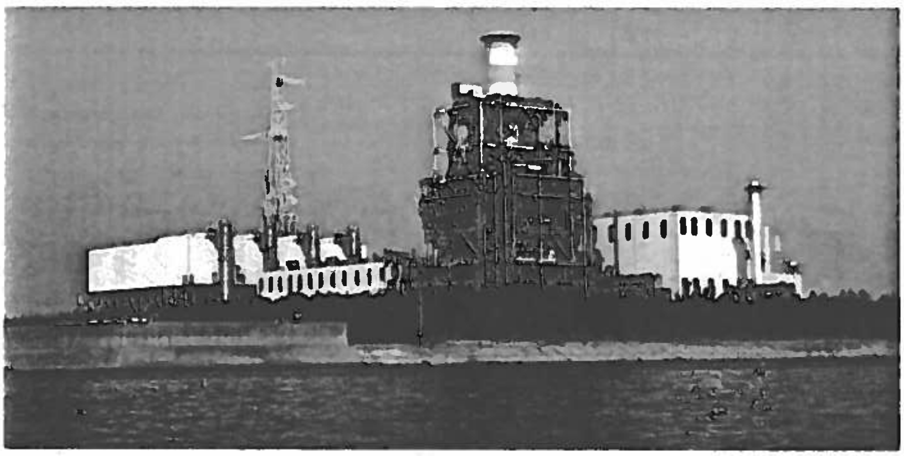
Until the 1990s, gas turbine prototypes were shop-tested and validated at "beta" sites where commercial power production was typically hampered by issues associated with the introduction of new technologies. In order to optimize the process of detecting and correcting defects during the validation phase, and to prevent exposing clients to the debugging process, Mitsubishi Heavy Industries Ltd. (MHI) introduced the concept of in-house validation under real operating conditions.

The plants providing this service are operated and maintained by MHI staff and sell their electrical output to local utility companies. Carlos Koeneke, vice president, project engineering at Mitsubishi Power Systems Americas Inc., told *POWER* in April that MHI built the first 50-Hz validation plant, K-Point, in Kanazawa in 1992. It was followed in 1997 by a 60-Hz counterpart in Takasago, called T-Point (Figure 1).

"These demonstration plants were the first of their kind and revolutionized the way validation of advanced gas turbines is performed," Koeneke said. "K-Point plant was decommissioned several years ago, but T-Point plant continues selling the generated power and even today, 14 years after T-Point went commercial, there is no other company that performs the comprehensive validation that the T-Point plant provides."

The highest cost of sustained long-term validation under real operating conditions is not the equipment but the fuel consumed. The T-Point plant is maintained and operated by MHI under dispatch instructions from the local utility (Kansai Electric). The plant is frequently started and stopped, and every single MW is sold under a contract, as with any other independent power producer. Koeneke explained that this arrangement "makes it possible, from the economic point of view, to sustain long-term validation operation."

1. Carrying its own financial weight. The T-Point combined-cycle plant is maintained and operated by MHI under dispatch instructions from the local utility, Kansai Electric. The plant is frequently started and stopped, and every single MW of generated electricity is sold under a contract. This makes it economically possible to sustain long-term validation operation. *Courtesy: Mitsubishi Heavy Industries Ltd. (MHI)*



A Strong Track Record

In addition to revolutionizing the way modern industrial gas turbines are validated, in 1997 the T-Point plant pioneered the introduction of steam cooling to gas turbines. Through extensive validation of the steam-cooled M501G gas turbine, as well as the upgraded M501G1 gas turbine in 2003, the T-Point plant delivered excellent results that facilitated deployment of the largest and most successful steam-cooled fleet of gas turbines in the market. To date, 47 units in operation have logged in excess of one million actual hours and 11,600 starts. This impressive G-Series record culminated with the introduction of the air-cooled version, which also was validated since 2009.

Operating and maintaining the demonstration plants in the same facility where design and manufacturing occurs (the MHI Takasago Machinery Works, which also includes a rheostat shop test facility that can be used to test off-frequency conditions) results in a smooth debugging process with a lower risk of failures and quick recovery after unforeseen issues, Koeneke explained. The validation process would not be representative of real operating conditions if the running modes were not determined by a real demand condition or if the duration of the validation run were restricted to only a few hundred hours due to the high cost of fuel. The T-Point plant has logged more than 2,300 start-stop cycles, 1,300 of those correspond to daily operating cycles. It has also operated more than 420 days, either continuously or under weekly start/stop cycles.

"Because of the lower failure and interruption risks, this demonstration concept is widely praised by the insurance community," Koeneke said. "The testing scope goes beyond the gas turbine. T-Point also has allowed testing of a number of innovations, including steam turbine upgrades, air-cooled condenser technology, generators, and static frequency converters."

Donald S. Schubert is the senior vice president of the Power Practice Division of Marsh Inc., an insurance company in the energy sector that provides coverage in the areas of project risk management, claims services, and errors and omissions protection for engineering services. He told *POWER* that he agrees with Koeneke's assessment of the value of the demonstration concept pioneered by MHI.

"Looking back at the history of all the [original equipment manufacturers'] efforts to test and validate their new engines, T-Point certainly leads historically for the application of 'load dynamic' testing," Schubert said. "MHI's early industrial approach was testing in a power plant environment where dispatch and loading of units are not under their control."

The insurance community's point of view shows that MHI's approach promotes advanced product validation in a non-owner operator environment, according to Schubert. The new engine validation "supports technology acceptance by the insurance markets by clarifying risks associated with new and upgraded designs."

Validating Upgraded Components During Periods of Low Demand

MHI uses periods of low demand to inspect the plant's equipment and to introduce upgraded components intended to promote enhanced reliability and performance, Koeneke said.

Designers and research and development staff based in nearby buildings have the ability to request the installation of temporary sensors that allow them to gather valuable insights pertaining to the modified parts. They have the invaluable opportunity to see immediate, first-hand results of their modifications and review their ideas to develop even better designs. Numerous improvements to the G-Series fleet of gas turbines were validated at the T-Point plant and consequently resulted in the high reliability this class enjoys.

Another Milestone: Demonstration of the M501J Gas Turbine

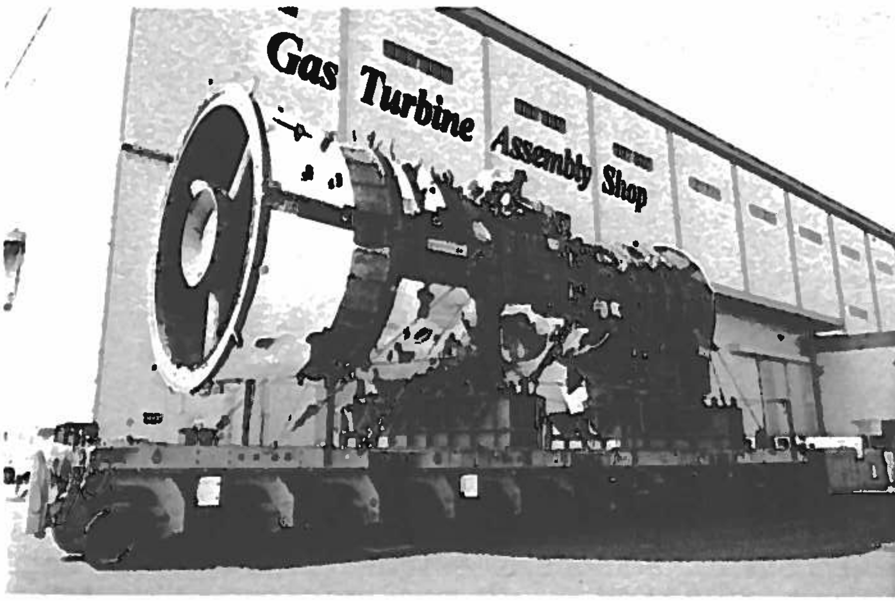
In November 2010, after T-Point staff completed validation of the air-cooled M501GAC gas turbine, they replaced this frame with the first M501J gas turbine (Figures 2 and 3). T-Point has achieved another unprecedented milestone with the ongoing demonstration operation of this turbine, which has a inlet temperature of 1,600C (2,912F). That's 100C higher than the current highest-temperature engine.

The 60-Hz J-Series turbine achieves a rated power output of about 320 MW (ISO basis) and 460 MW combined-cycle power generation. According to MHI, this new gas turbine is able to withstand temperatures 100 degrees higher than the company's existing 1,500 C-class G-Series gas turbine because of a low-thermal-conductivity thermal barrier coating technology and improvements in cooling efficiency. The adoption of an enhanced three-dimensional design contributes to improved aerodynamics. In the J-Series gas turbine, the compressor is designed to provide a higher compression ratio, while the combustor carries on the steam-cooled technology originally developed for the G-Series turbine.

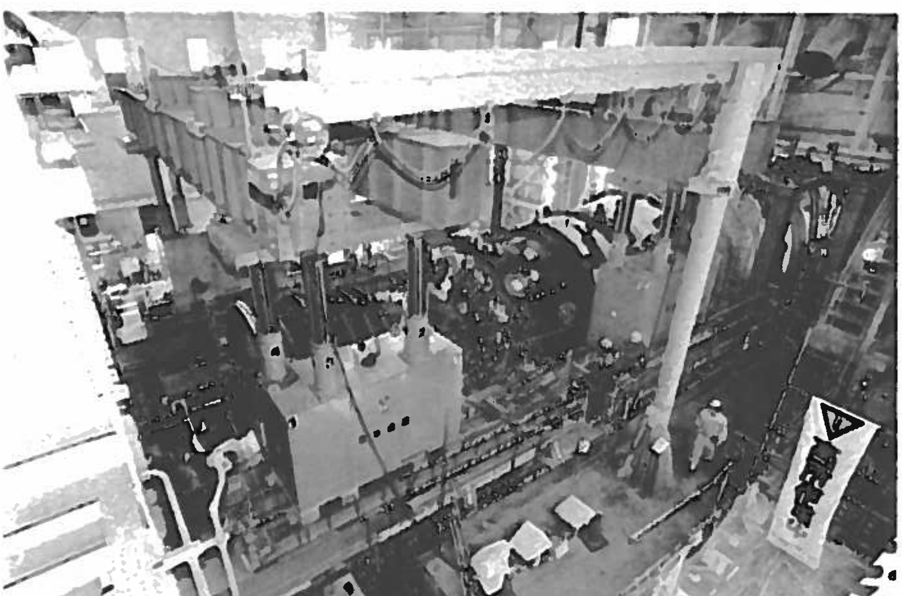
"We have rheostat capabilities at Takasago Machinery Works, but it is naive . . . to assume that the short-term shop test operations with or without off-frequency operations can replace true validation under 'demand conditions,'" Koeneke said. However, "Validation should replicate as much as possible the operating conditions the equipment will be exposed for years to come, and no demonstration plant in the world has achieved this task better than the T-Point Plant." ■

—Angela Neville, JD is POWER's senior editor.

2. Traveling turbine. The M501J gas turbine is prepared for transportation to the T-Point plant for validation testing. *Courtesy: MHI*



3. Making the mark. The T-Point achieved another unprecedented milestone with the ongoing demonstration operation of the M501J gas turbine, which has a turbine inlet temperature of 1,600C (2,912F). *Courtesy: MHI*



Selecting Your Next Combustion Turbine

With natural gas serving as the *fuel de jour*, many utilities and merchant generators will be considering the purchase of new combustion turbines in the near future. If you are in the market for a gas turbine, here are some key design features you should discuss with turbine vendors prior to your next purchase.

By Amin Almasi, WorleyParsons Services Pty Ltd.

The growth of the combustion turbine (CT) market over the past two decades has been facilitated by progress in three technologies:

- Metallurgical advances that have made possible high temperatures in turbine components (especially turbine blades) and combustors.
- The advancement of aerodynamic and thermodynamic knowledge (especially from aircraft and spacecraft industries).
- Advanced computer technology used in the design and simulation of turbine airfoils, combustors, and turbine blade cooling configurations.

Combined, these advances have made possible CT designs with state-of-the-art 1,600C (2,912F) turbine inlet temperatures and combined-cycle efficiency pushing the 60% thermal efficiency barrier.

The challenge for a purchaser of a new CT is what questions to ask, given that these design advances are not readily apparent. The discussion that follows is not meant to tell a manufacturer how to design a CT, nor is it comprehensive. Rather, it is intended to prompt some useful planning before a potential buyer has the first technical discussion with a potential supplier.

Turbine Configurations

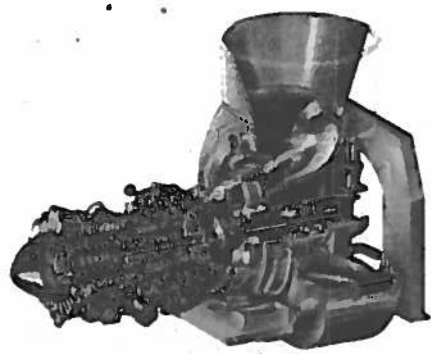
CTs are usually categorized as either heavy frame industrial or aero-derivative gas turbines, although a few turbines have recently adopted features of both design types. One good example of a "hybrid" is General Electric's LMS100; it has a Frame 6FA low-pressure compressor and a CF6-80C2 high-pressure compressor.

In general, the differences between the aero-derivative and industrial turbines are weight, size, combustor and turbine design, bearing design (antifriction bearings for aero-derivative turbines and hydrodynamic ones for industrial turbines), and the lube oil system. Industrial turbines are also field erected and maintained in place, whereas aero-derivative turbine plants are designed for a quick replacement of the entire engine when maintenance is required.

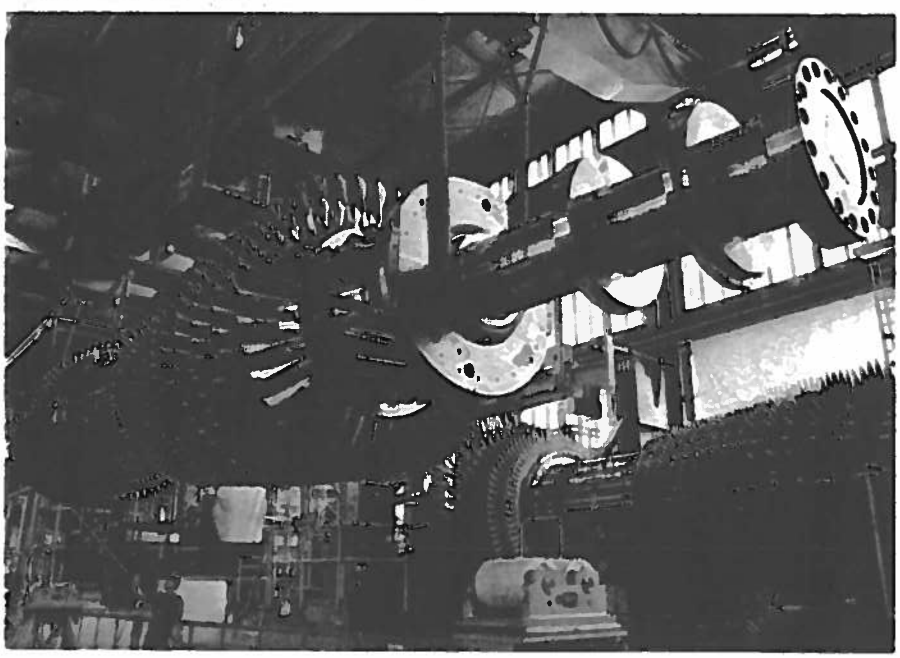
Manufacturers of aero-derivative CTs include General Electric, Rolls Royce (Figure 1), and Pratt & Whitney. Manufacturers of industrial CTs include Siemens (Figure 2), Mitsubishi (see page 54), Alstom (Figure 3), General Electric, and Solar Turbines Inc. Each manufacturer's CT is available in 50-Hz and 60-Hz models.

Selection of CT type is usually made based on the nature and location of service and a long list of site-specific design

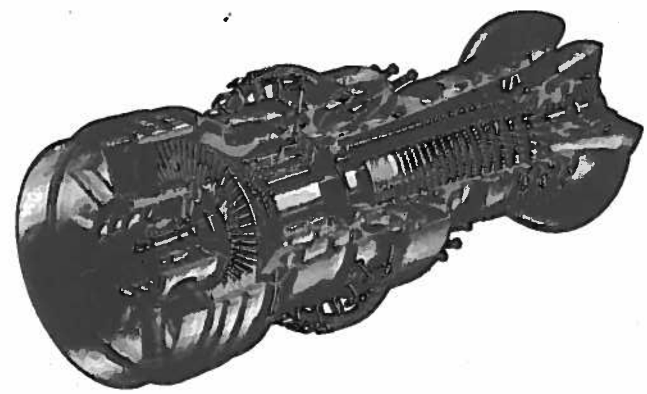
1. Rolls Royce RB211. The 44-MW engine upgrade released by Rolls Royce in mid-2010 boasts a 41.5% thermal efficiency. The high-pressure turbine and much of the triple-spool compressor is based on aero engine technology. *Courtesy: Rolls Royce*



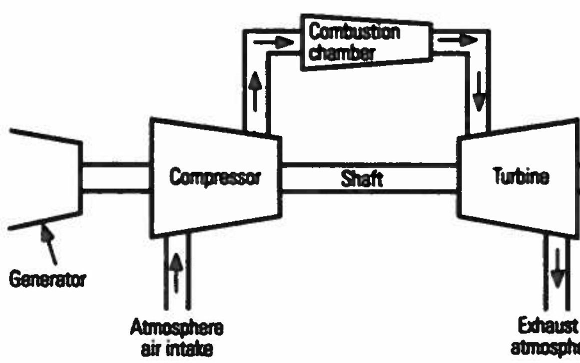
2. Siemens SGT6-8000H. Siemens Energy introduced the 60-Hz version of its combustion turbine in June 2010. The 274-MW turbine features a turbine inlet temperature of 1,500C. This turbine can go from standby to start in 5 minutes and can reach full power in 15 minutes. *Courtesy: Siemens Energy*



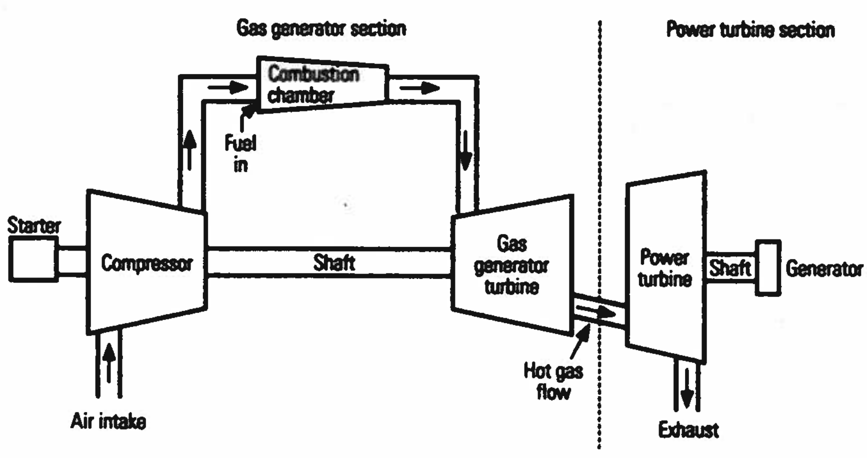
3. Alstom GT24/26. The sequential combustion system is a unique feature of the GT24/26. Compressed air is heated in the first combustion chamber (EnVironmental or EV combustor) by adding about 50% of the total fuel (at baseload). The pressure is halved after the combustion gases expand through the single-stage high-pressure turbine. The remaining fuel is added into the second combustion chamber (Sequential EnVironmental or SEV combustor), where the combustion gas is heated a second time to the maximum turbine inlet temperature. The gas then expands through a four-stage low-pressure turbine. *Courtesy: Alstom*



4. Cold-end-drive option. The typical single-shaft combustion turbine has the compressor and turbine sections on opposite ends of the shaft. The driveshaft in this figures extends from the compressor section, hence it is a cold-end-drive engine. If the driveshaft extended from the turbine end, it would be a hot-end-drive engine. *Source: WorleyParsons Services Pty Ltd.*



5. Two-shaft option. The typical two-shaft or split-shaft combustion turbine configuration places the compressor and gas generator turbine on a common shaft. The hot exhaust gases "aerodynamically" connect the power or free turbine to produce shaft power for the generator or other driven load. The advantage of this configuration is that the output shaft speed can be controlled to that required by the generator to eliminate a gearbox. Aero-derivative configurations use multiple gas generator sections on concentric shafts to improve efficiency. *Source: WorleyParsons Services Pty Ltd.*



and economic factors that are usually led by the projected price of natural gas. The conventional wisdom was once to place aero-derivative units in remotely located applications (including offshore) and to place heavy frame industrial units in easily accessible baseload applications. However, about 10 years ago in the U.S., the combined cycle, based on the aero-derivative turbine, became very popular given both the speed at which a plant could be constructed and its superior efficiency.

Both CT types are available in different configurations. In the hot-end-drive configuration the output shaft is at the turbine or exhaust end, where the higher temperatures can affect bearing life and make servicing of those bearings more difficult. In the cold-end-drive configuration, the output shaft extends out the front of the compressor, allowing the exhaust gas flow to be axial in some models (Figure 4). With a cold-end-drive turbine, the driven equipment is also relatively cooler and easier to service. However, the compressor inlet and ducting must be configured to accommodate the output shaft and the driven equipment. In sum, the CT configuration is usually selected, when possible, by application and site configuration.

Single-spool, integral output shaft CTs (in both hot-end and cold-end-drive configurations) are used primarily to drive electric generators. However, the high torque required to start pumps and compressors under full pressure results in high turbine temperature during the start-up cycle when internal cooling airflow is low or nonexistent. The solution has been to connect a single (or two or three) spool compressor/turbine section (also called a gas generator) that produces hot gases to a separate power or free turbine. The gas generator is not physically connected to the power turbine shaft but is coupled aerodynamically (Figure 5). Also, the power turbine can be designed to operate at the same speed as the generator, not the gas generator, and often eliminates the need for a gearbox to match speeds. (Typical gearbox losses are 2% to 4% of power.)

Keep It Clean

It's often said that the key to achieving maximum CT life is keeping the combustion air, fuel, and lubricating oil clean. There are few areas in the plant where an owner can more easily improve long-term performance, and therefore profitability, of the plant than in these three systems.

Clean Air. The inlet and exhaust systems should be selected for the minimum practical pressure drop because those losses are paid for every hour that the plant operates. The filter should remove 100% of particles in the inlet air that are 3 microns and larger and, at minimum, 99% of particles 0.5 to 3 microns. Be sure to include an entry screen to prevent debris from entering the filter house; orient the air inlet, louver, or cowling to minimize entry of driving rain, snow, or sand; also ensure that there is good access to all parts of the air filter module for maintenance and filter element replacement.

The optimum duct design will:

- Minimize the number of direction changes required before the air enters the compressor, including required turning vanes (to ensure uniform flow distribution and avoid resonance).
- Limit the inlet air velocity to between 20 meters (m)/s and 30 m/s.
- Design ducts to be sufficiently rigid to avoid vibration (plate 5 to 10 millimeters thick is generally used).
- Include plenty of man-ways for cleaning and inspection.
- Include a differential-pressure alarm for each stage of filtration.

At the end of construction, thoroughly clean the air side of the inlet filter and ductwork to eliminate any objects, no matter how small, that could come loose during operation and cause catastrophic damage to the CT.

If the CT is located close to the seacoast, sea salt ingestion will rapidly cause sulfidation or hot section corrosion, so make sure the filter system materials and level of filtration are proper for the location.

Here are a few other tips for selecting equipment:

- Don't skimp on the materials inside the filter house and ductwork. The filter house, inlet silencer, and perforated plate elements should be fabricated from suitable grades of stainless steel.
- Make sure the silencers have a rigid structure to prevent damage due to acoustical or mechanical resonances or differential thermal expansion.
- The ducting and casing design should permit field balancing in the end planes of the rotors without requiring the removal of major casing components.

When determining the arrangement of the plant, make sure the air inlet is upstream of the exhaust stack during prevailing wind conditions to avoid recirculation of exhaust gases under any projected wind conditions. A good recommendation is to keep a minimum horizontal separation of 7.5 m. The air inlet (elevated a minimum of 5 m) and CT exhaust should also be located outside a three-dimensional fire hazardous zone and outside any classified electrical area.

Clean Oil. A good gauge of the oil cooling system design quality is to confirm that the inlet oil temperature and oil temperature rise through the bearing are less than 50C and 33C, respectively. Another good idea is to include a full-size, redundant shell and tube lube oil cooler configured with a removable tube bundle and redundant oil filters with removable elements. Also be sure to use stainless steel for all lube oil piping and valves—accept nothing less.

It's often said that the key to achieving maximum CT life is keeping the combustion air, fuel, and lubricating oil clean.

Each oil supply line to critical components should be individually monitored, mainly for oil pressure. We recommend that the oil reservoir retention time should be at least 8 minutes. For aero-derivative CTs (that have antifriction bearings and use synthetic lubrication oil), the turbine lubricating oil system usually should be separate from the driven equipment (such as the generator) lubricating oil system. We also strongly recommend that CTs equipped with antifriction bearings should be instrumented with metal chip detection, an online metallic debris monitoring system. Industrial CTs, which normally use hydrodynamic bearings and mineral oil–based lubricating oil, typically have a single integrated oil system for the entire driveline.

Clean Fuel. Designing a combustor is a complex task, often likened to lighting a match in a hurricane. For most CTs, there are two distinct configurations: the can-annular (a number of combustor cans arranged around the circumference of the CT) and the annular design, which includes the single-can option.

The design of the fuel supply system is critical and requires special attention. Always include a fuel strainer (a Y-type strainer with stainless steel internals) and a blowdown system (manual valve) for purging and warming up the fuel system for approximately 20 minutes prior to starting. A manual valve closed about 2 minutes after starting should be included as well as a safety shutdown valve. The plot limit valve (fail safe) for trip on gas knockout drum high liquid level (manual and automatic) preceded by a high level alarm is required in any robust fuel system design. Also consider including a fuel gas superheater designed to deliver 40C fuel gas to prevent condensate mist carryover or hydrate formation. If fuel gas compression is required, screw compressors always seem to be the optimal selection.

The fuel control system should also include a shutoff valve (separate from the fuel control valve) that stops all fuel flow to the turbine on any shutdown condition (local and remote tripping) and that cannot open until all permissive firing conditions are satisfied. Fuel shutoff valves should have a remote shutdown actuator and a partial stroke feature to permit field checking of the operability of the shutoff valve during normal operation of the CT.

Driveline Design

The rule of thumb for power generation packages is that the generator shaft diameter should be equal to or greater than the CT shaft diameter. For mechanical drive, shafts should have approximately the same diameter. When torsional vibration problems appear, the primary cause is the lack of a comprehensive torsional analysis, improper coupling selection (mainly flexible couplings), and lack of proper operation and maintenance.

Most original equipment manufacturer (OEM) designs make certain that the blade natural frequencies do not coincide with any source of excitation from 10% below minimum governed speed to 10% above maximum continuous speed. For the entire driveline, there is the potential for torsional, lateral, or blade resonance to cause fatigue failure. The coupling between the turbine and gearbox or gearbox to generator, for example, is the best option for tuning the torsional character of the driveline. There are a couple of coupling options: high torsional stiffness (preferably dry flexible diaphragm type)—or direct forged flanged rigid connection (which is optimum, if allowed by torsional analysis), and a flexible coupling with more elasticity, damping, and more maintenance.

The coupling torque is usually chosen on the basis of average requirements for full load, but it also must have a sufficient service factor to handle likely overload (such as electrical faults). A pulsation of generator load caused by current pulsation is an important concern, especially for a CT or a plant electrical network that is connected to a relatively weak electric system. Our comparative analysis showed a >25% error in shaft stiffness and inertia between detailed finite element analysis and simplified calculation methods. Rotor torsional data coming from simplified methods may lead to missing (or shift of) torsional critical speed(s) and torsional problems. Make sure the OEM supplies a stress and vibration analysis of your turbine configuration rather than just a "typical" report.

Take special care with the starting device selection and rating. The preferred starting device is electro-hydraulic (an electric motor drives a hydraulic pump, which in turn transmits hydraulic power to start the gas turbine) and rated to supply, at a minimum, 110% of the starting and acceleration torque in worst-case conditions. The typical criterion for selection is that the starting system should be capable of an immediate hot start anytime after a unit trips for three consecutive start attempts. Cold-start and hot-start restrictions are also very important and greatly affect the starting reliability and, perhaps, the forced outage rate of the plant.

Manage Performance Degradation

Turbine stage degradation cannot be avoided but can be slowed. It also has a cumulative effect. A degraded stage (a single wheel with blades along the periphery) will create different exit conditions, causing each subsequent stage to operate further away from its design point.

The main causes of blade degradation are increased tip clearances, changes in airfoil geometry, and changes in surface quality. The cause of degradation is blade fouling, caused by particles that stick to blade airfoils and annulus surfaces, or hot corrosion, the loss or deterioration of material by chemical reactions from components exposed to hot gas. The corrosion is caused by both the hot gas and contaminants.

Erosion also occurs in the same regions as hot corrosion. Erosion is the abrasive removal of material from the flow path by hard or incompressible particles impinging on flow surfaces. Abrasion is caused by foreign objects in the gas that strike the flow path components and when a rotating surface, such as the tip of a blade, rubs on a stationary surface.

Good inlet air and fuel filtration will help defeat foreign object–caused damage, although sodium in the inlet air and sulfur in the fuel will always cause some fouling and corrosion in the hot gas path.

Include Condition Monitoring

Condition monitoring is particularly cost-effective when malfunctions are identified before a severe failure occurs. The best tool available is vibration monitoring. We recommend casing vibration monitoring (a minimum of two sets for compressor and turbine casings) with both velocity measurements for low-speed vibrations up to 2 kHz and accelerometers for high-speed vibrations and for hot sections. Noncontacting probes should be used for axial and radial vibration monitoring. These measurements include journal bearings, noncontacting X-Y probes mounted at a 45-degree angle from the vertical centerline, and a velocity seismic transducer for bearing housings and dual probes axial position for thrust bearings.

Temperature monitoring is also an important element of a robust condition-monitoring system. We recommend temperature monitoring of oil, including the lubricating oil drain thermocouples for alarm and emergency shutdown and hydrodynamic thrust and radial bearings with replaceable resistance temperature detectors (RTDs). We also recommend temperature monitoring of the hot air path flow.

Over-temperature protection should be independent of the CT combustion control system to add another level of operating redundancy. Six thermocouples placed around the turbine exhaust gas frame to measure exhaust gas temperatures for alarm and trip are usually sufficient.

Our normal design approach is to include triple-redundancy instruments to the electronic governor. That means that there are three input sensors, with two out of three voting logic. This approach will prevent, for example, CT speed increases beyond the overspeed limit in the case of a loss of rated load or a coupling failure. For multiple-shaft CTs, each shaft should have its own overspeed protection system with online testing capability; the overspeed trip system is independent of the governor system. Our standard design monitors overspeed, low fuel supply, combustor flame out, low lube oil pressure, and radial and axial shaft vibration, in addition to the measured parameters of the driven equipment as the source of shutdown signals.

Always Operate Safely

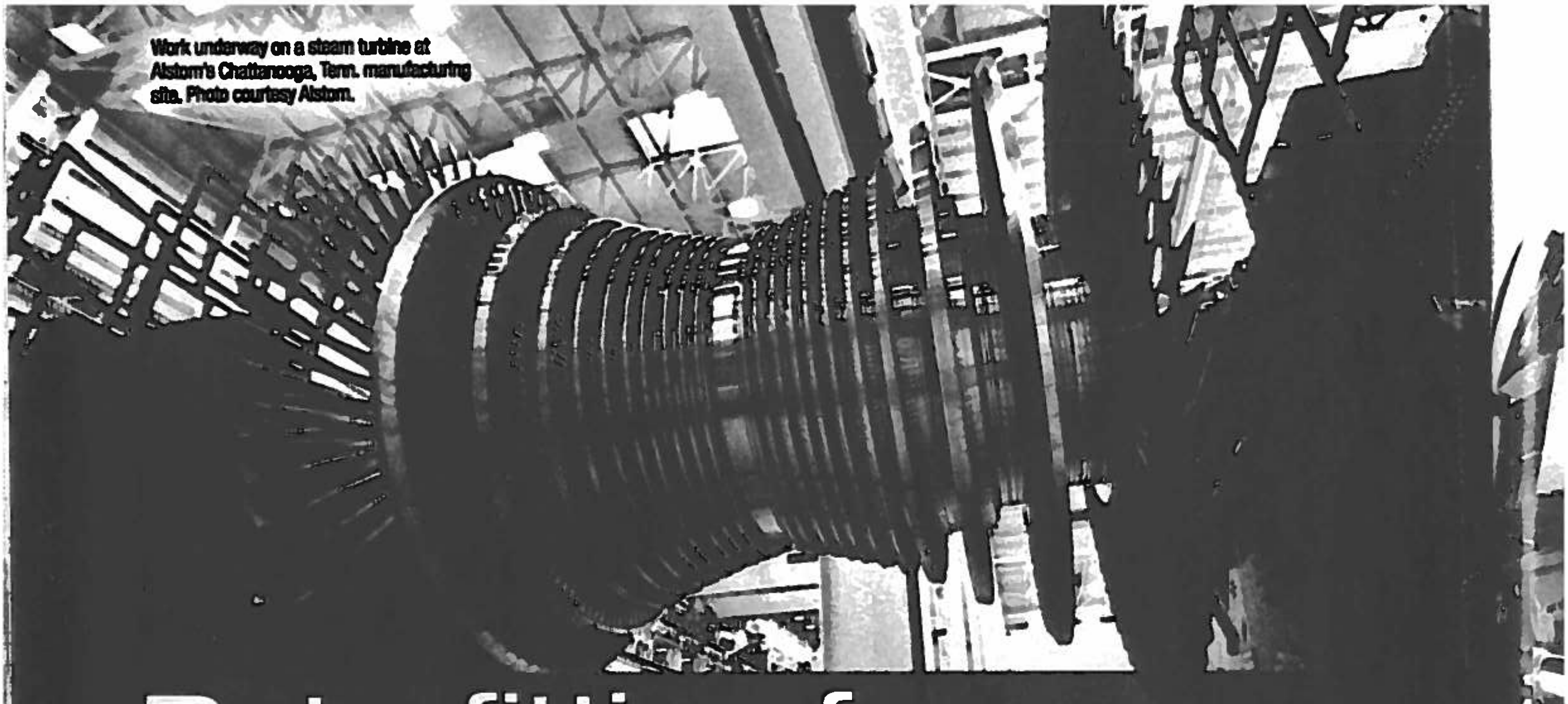
Our design approach for a system gas purge is to replace a minimum of six times the exhaust system volume (including turbine, exhaust duct, waste recovery device, exhaust stack, and so on) before firing the unit. The ignition temperature of the gas must always be higher than the surface temperature of the gas turbine. A HAZOP (hazardous operations) review (action and response) should be conducted with consideration of all possible malfunction scenarios, including failure of individual instruments and components. As part of this review, consider cases of possible reverse flow, higher flow, all scenarios of tube rupture or component damage, and all potential cases of gas to atmosphere that may form flammable gas clouds.

The design of the enclosure ventilation system must produce a negative pressure within the enclosure (when located within a safe area) or a positive pressure (when located within a hazardous area). We recommended at least two 100%-sized ventilation fans with automatic start controls.

O&M Intervals

A well-built CT should have the design life of its principal components—including rotors, casings, bearing housings, supports, and base-frame. At a minimum of 160,000 operating hours, that would be about 20 years, when the time between starts is about 80 to 100 hours. With many combined-cycle plants now cycling daily, that design life will be reduced. How much the design life will be shortened is project-specific and requires much analysis by the OEM. However, under normal operation, expect the planned time between major overhauls to be 40,000 fired-hours (five years), 16,000 fired-hours (two years) for hot gas path inspection, and 8,000 fired-hours (one year) for borescope inspection. These intervals will need to be shortened, sometimes significantly, when turbines are cycled daily or weekly. ■

*—**Amin Almasi** (amin.almasi@worleyparsons.com) is a lead rotating equipment engineer for WorleyParsons Services Pty Ltd., Brisbane, Australia.*



Work underway on a steam turbine at Alstom's Chattanooga, Tenn. manufacturing site. Photo courtesy Alstom.

Retrofitting for a Changing Market

An aging fleet, stricter emission legislation and the need to make plants more competitive as gas prices plunge, are driving the U.S. steam plant retrofit market.

By Charles Athanasia, Vice President, Thermal Services North America, Alstom

Reliability has for many years been the main driver for retrofitting an aging U.S. coal fleet. More recent drivers include tougher environmental legislation and the growing use of natural gas.

Today, the combination of stricter emission limits, reduced short term demand for electricity, low natural gas prices and the superior operational flexibility of gas-fired plants are placing new pressure on coal plants. As a result, many coal plant owners are either shutting down plants or re-evaluating their generation strategies and the positioning of their generating assets.

The plant operator's reality is changing, and that means it's time to re-examine some of the traditional thinking around steam turbine versus 'whole plant' retrofit strategies.

Integrated Retrofit

Some North American power plant operators have expressed interest in integrated retrofit plans that take into account all major plant components, from the boiler through turbines and generators. The goal: to develop a retrofit program that delivers the highest possible return on investment.

One of the primary drivers for this shift in customer thinking is the push to satisfy new environmental regulations by lowering power plant emissions. Operators aiming to reduce emissions while keeping coal in their portfolio face not only the cost of installing and upgrading emissions control equipment, but also the need to regain the output lost to the parasitic load of that equipment.

Traditionally, operators have approached retrofits on a component-by-component basis – a methodology driven largely by short-term cost considerations. Today, the economics of environmental compliance are bringing new variables into the retrofit equation. A high-pressure steam turbine retrofit is, from the operator's perspective, a fairly attractive way to increase plant performance by 2 to 3 percent. However, a slightly higher initial investment in an integrated retrofit program that covers the boiler, turbine and generator can satisfy operators' regulatory requirements while achieving increases in plant performance significant enough to make the integration of these retrofit activities more cost-effective in the long run. The economics are simple. Invest a little more today for greater returns tomorrow.

If we take a closer look at the technical realities of a truly integrated plant retrofit program, several key considerations must be taken into account. First, maintaining net power output to accommodate new environmental control systems calls for a careful analysis of the complete steam cycle to determine where efficiencies can be gained, improvements can be made, and how upgrades of various components will impact the rest of the cycle.

Next, there typically is a requirement to maintain the original design steam temperature that is driven largely by the significant hardware costs involved in changing it. The majority of turbine retrofits are therefore designed around the plant's existing steam temperature.

Finally, a truly integrated performance retrofit program requires significant expertise in both boiler and steam turbine technology.

In 2007, Minnesota Power contracted Alstom to perform an Optimized Plant Retrofit (OPR) study on Units 3 and 4 of its coal-fired Boswell Energy Center in Cohasset, Minn. The OPR examined the plant's boiler, auxiliary components and steam turbine to identify the modifications needed to boost output performance to a level that would drive new emission control equipment.

The Boswell 3 OPR recommended modifications to the boiler pressure parts, firing system, high and intermediate pressure turbine modules and other smaller auxiliary components. Based on its findings, Alstom was tapped to provide the HP/IP turbine retrofit for Unit 3, in addition to a new low temperature super heater for the boiler and a new low NO_x burner system with over-fire air.

"Customers need certainty in the marketplace to advance large-scale retrofit investments."

For the turbine portion of the project, Alstom's scope of supply included the design, manufacture and delivery of new rotating parts including the rotor and new blades, as well as stationary parts ranging from a new inner casing and diaphragms to other assembly parts. On location, Minnesota Power removed the old HP/IP module so only the turbine outer casing remained. The new parts were then reassembled and installed and the upgraded unit completed its warranty period in October 2011.

The result of this holistic approach to the Boswell 3 retrofit was an increase in performance beyond what was needed to cover the power requirements of new environmental control equipment. This not only satisfied the customer's regulatory compliance needs, it positively impacted the plant's financial equation.

The Boswell 3 retrofit also exemplifies customers' growing interest in turning to new partners for their retrofit needs as opposed to working solely with their original equipment manufacturer. In this instance, the steam turbine and generator originally were supplied by General Electric. In a separate contract for Boswell Unit 4, Alstom retrofitted the HP/IP and two LP modules of a Westinghouse steam turbine.

Repowering

The economics of natural gas have some customers considering whether or not to repower older, conventional gas or coal-fired boilers and convert them to combined cycle gas turbine (CCGT) plants. At today's gas prices, these plants can be dispatched at around $10/MWh lower than a comparable coal plant, and they offer the added benefits of higher efficiency, greater operational flexibility and lower emissions.

Even in a repowering scenario where the boiler is replaced with a gas turbine and HRSG, an integrated approach that optimizes interactions between plant components can positively impact the broader performance of the plant. The steam turbine, for example, must be retrofitted to suit the new steam being supplied from Heat Recovery Steam Generator (HRSG).

Depending on the heat balances and steam flows provided by the HRSG, changes likely must be made to the steam turbine's HP and IP modules. The LP section is not subject to the same steam temperatures and pressures as the HP section and generally can remain untouched except in the case of potential reliability issues.

Extracting the most efficiency from new steam conditions usually requires a complete change of the rotor, which means the inner casing of the HP and IP turbine also has to be replaced. Although it varies from project to project, generally an old outer casing will remain intact, sitting on its bearing centers. This avoids any alteration to the civil works.

In 2008, Alstom signed a contract in the Netherlands to convert the 640 MW Claus B Unit, a conventional steam power plant burning natural gas, into a combined cycle power plant. The conversion increased output of the unit to 1304 MW net, reduced CO_2 emissions by 40 percent, and increased efficiency from approximately 39 percent to 59 percent net.

The project included replacement of the existing steam turbine and its auxiliary equipment with a retrofit steam turbine. Alstom's engineers defined a steam turbine and turbine island solution to best match the new steam conditions and the layout of the existing power plants.

The turbine island solution for Claus B included new balance of plant equipment, re-use of the main water cooling system, integration of new and existing instrumentation into a new control system, and various other services.

The team re-designed the steam path and blading in order to achieve the maximum possible full and part load output within the defined operating range. All the optimizations put in place considered the specific steam conditions and operating flexibility requested by the customer. These were achieved without penalizing the maintainability and the lifetime of the components. The retrofit steam turbine now generates 487 MW from the steam supplied by the three new HRSGs.

In this project, the existing single flow HP and double flow IP turbines were removed completely with the exception of the bearings and pedestals, which were reused. The inner casings and rotors of the three double flow LP turbines were removed and replaced with a new design fitting into the existing outer casing. The existing combined control and lube oil system were replaced by a separate control oil system and a refurbished lube oil system. The remaining systems, instrumentation and controller are all new.

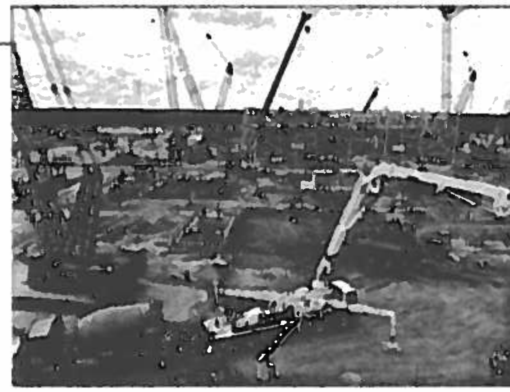
Alstom won a similar contract in 2011 to carry out a repowering project of the El Sauz power plant in Mexico. The gas-fired plant, which consists of three gas turbines and an 80 MW steam turbine, entered operation in 1981 and is owned and operated by Mexico's state-owned utility, Comision Federal de Electricidad (CFE). Under the contract, Alstom is providing a new GT24 gas turbine to replace the existing gas turbines while also retrofitting the plant's steam turbine. The repowering project will add at least 25 years to the plant's lifetime and boost its efficiency by 20 percent.

Preparing for the Market

With low gas prices and stricter environmental legislation, operators' appetite for plant retrofits and repowering will continue to grow in popularity in the coming years.

Customers need certainty in the marketplace to advance large-scale retrofit investments. Environmental regulations are having a more substantial impact, but in the absence of a clear long-term policy landscape, plant operators should take an integrated, 'whole-plant' approach to retrofit projects to ensure their investment has the best possible long-term impact on their bottom line. pe

Construction on Mississippi Power's Kemper County coal-fired power plant is underway. The plant will feature Transport Integrated Gasification technology (TRIG), which would result in 65 percent carbon capture.



EPA proposes first carbon standard for future power plants

By Lindsay Morris, Associate Editor

The U.S. Environmental Protection Agency (EPA) has proposed the first Clean Air Act standard for carbon pollution from new power plants. The proposal, which was released March 27, does not apply to plants currently operating or new permitted plants that begin construction over the next 12 months.

The proposed rule, known as the New Source Performance Rule, would require any new power plant to emit no more than 1,000 pounds of carbon dioxide (CO_2) per megawatt of electricity produced. The average U.S. natural gas plant, which emits 800 to 850 pounds of CO_2 per megawatt, meets that standard; coal plants, however, emit an average of 1,768 pounds of CO_2 per megawatt.

EPA Administrator Lisa P. Jackson said the Administration is aware of 15 projects in the permitting process or currently under construction that would be potential beneficiaries of the exemption – six possible CCS facilities and nine conventional power plant proposals.

> "By banning the future of efficient and effective coal in the U.S., coal may instead be exported and used overseas." Scott Segal

The proposed rule is not an effort to terminate coal generation, Jackson said. "We believe that coal will remain an important part of America's electric generating mix; (it will) remain the largest single source of electricity in our nation's future."

In fact, EPA does not project additional cost for industry to comply with this proposed standard.

However, many in the power industry view the proposed NSPS as an attack on coal generation. "By banning the future of efficient and effective coal in the United States, coal may instead be exported and used overseas," said Scott Segal, executive director of the Electric Reliability Coordinating Council.

The proposed carbon legislation is the third strike against coal-fired power generation in the past year. One of the biggest concerns to power generators is the recently finalized Mercury and Air Toxics Standard (MATS), EPA's mandate to limit mercury emissions from coal-fired units. The rule will also curtail a number of hazardous air pollutants (HAPs), including lead, arsenic, hydrogen chloride, hydrogen fluoride and dioxins/furans. MATS will require the power industry to reach compliance by 2015.

Another ongoing compliance concern is the Cross State Air Pollution Rule (CSAPR), which is set to limit sulfur dioxide (SO_2) and nitrogen oxide (NO_x) emissions from power plants in 27 states. CSAPR was stayed by a federal court in December but may be re-released this summer.

The proposed greenhouse gas rule could potentially upset the control of HAPs, NO_x and SO_2, that are intended to be controlled by the other two rules, said Jane Montgomery, partner at Schiff Hardin LLP. "To add this kind of layer on top of these rules would be insanity." Emissions controls installed on power plants to reach compliance for CSAPR and MATS, such as flue gas desulfurization (FGD) with limestone and mercury controls with resin, can effectively increase CO_2 emissions from a power plant. Therefore, the potential counter-balancing of rules creates a "mind-boggling mess," Montgomery said.

Some in the power industry believe the Administration is pushing for a gradual shift toward natural gas through the NSPS, as well as the other recent regulations. But with gas prices facing remarkably low rates, an industry-wide switch to natural gas could be perilous if prices escalate again.

Jackson said EPA considered during the rule planning how electric power generation could be affected if natural gas prices increased. "It's fair to say the price would have to rise dramatically … for the economics of this rule to change," Jackson said.

Other concerns, such as proximity, must be considered before converting to gas. If a proposed natural gas power plant is not next to a power plant, "that makes pipeline battles more likely," Montgomery said. "There are a number of coal units that want to switch to natural gas, but they cannot get a pipeline."

Larry Goldenhersh, CEO of Enviance, an environmental data software provider, said that while these EPA rules may encourage utilities to explore natural gas options, the rules are ultimately "about air quality; not natural gas."

Compliance Options

Under the proposed regulation, new coal plant operators will have two options for compliance: Using carbon capture and sequestration (CCS) technology to limit carbon emissions, or averaging carbon emissions over a 30-year period.

For the first 10 years of the 30-year averaging, a plant would be permitted to emit up to 1,800 pounds of CO_2 per megawatt. Starting the eleventh year, the plant would be required to emit just 600 pounds of CO_2 per megawatt.

Segal said that CCS technology is "still highly speculative, likely expensive, and EPA has provided no assurance that it will help with inevitable permit delays."

The cost of CCS varies per plant based on scenario, but is largely seen as an expensive, unproven technology. According to a report by the Intergovernmental Panel on Climate Change, a CCS installation at a coal plant could increase generation costs by as much as .06-.10 cents/kWh. For plants in most states, where the price of coal generation ranges from .05 - .08 cents/kWh, CCS could effectively double generation costs.

Gasifier at the 582 MW Kemper County plant.

CCS costs are ultimately determined by how far gas has to be pumped from the plant to a sequestration site. If a sequestration site is installed at a power plant, costs will be less, said Montgomery. "If you have to purchase the land, pump the gasoline from someone, etc., then that adds a different layer of cost."

The risk of sequestered carbon must also be taken into account when considering a CCS installation. "If you have carbon at the bottom of a sequestration well, it's growing in risk each year," Goldenhersh said. As carbon grows in risk, it inevitably grows in cost. "Over time, it seems highly unlikely that as carbon goes up in costs, coal-fired plants will be allowed to continue to operate from an economic sense."

Todd Palmer, a partner at Michael Best & Friedrich LLP, said there could be other options for complying with the proposed regulations, such as designing a new fossil-fired facility as a combined heat and power plant (CHP). "We're going to see more and more industrial facilities looking at on-site CHP. The power from the CHP unit would go to the host facility; it would not be sold retail, and therefore would not be subject to this rule."

Another compliance option for the proposed NSPS could exist in technology like the Transport Integrated Gasification technology (TRIG) currently being installed at Mississippi Power Company's proposed Kemper County coal-fired power plant. According to parent company Southern Co., the TRIG technology installed on the 582 MW plant would result in 65 percent carbon capture, making CO_2 emissions equivalent to a similarly sized natural gas combined cycle power plant.

TRIG technology was developed by the Department of Energy, Southern Co. and KBR at the Power Systems Development Facility in Wilsonville, Ala. In addition to carbon capture, the technology is also effective at capturing SO_2, NO_x and mercury.

> **"Coal will remain an important part of America's electric generating mix."**
> **Lisa P. Jackson**

Montgomery said the impending rule could give rise to the creation new technology options that are more commercially viable than CCS. "If your business is being cut off at the knees, you come up with something to try to fix it."

What About Existing Units?

While Jackson said that EPA has "no plans" to adjust greenhouse gas levels at existing plants, some in the power industry fear that EPA might create such a regulation after the November presidential election.

"We have little confidence that the Administration will adhere to this view, particularly after the election is over," Segal said.

Some in the power industry argue that it would make little sense for EPA to impose a rule on only new coal units and not existing ones. Randy Rawson, president and CEO of the American Boiler Manufacturers Association, said that only having a greenhouse gas rule limiting new coal is reminiscent of the Clean Air Act in its original form in 1970. "It originally exempted older power plants and refineries from the stringent pollution limits. During the haggling in Congress, electric utility officials convinced the bill's lead author, Maine Senator Edmund Muskie, that most of those creaky older plants were soon going to be mothballed anyway, so there was no point in forcing companies to shell out money to clean them up."

However, events did not carry out as planned. Power companies found it profitable to keep their oldest, dirtiest power plants alive for as long as possible. Rawson said since the proposed NSPS dictates that no coal-fired power plant can be built that emits more than 1,000 pounds of CO2 per MWh, older, dirtier coal plants will get off scotch-free as far as carbon goes unless rules on existing units are imposed.

For example, Rawson said, if a utility wanted to replace one of its older coal-fired power plants (one that emitted 2,100 pounds/MWh) with a newer, cleaner supercritical pulverized plant (one that emitted 1,600 pounds/MWh), it would not be able to under the proposed rule. This kind of logic leads many in the industry to believe that carbon legislation on existing units will eventually be imposed, if the NSPS goes through.

Before the rule is finalized, it will first have to face federal lawsuits already in existence. "Lawsuits are currently pending as to whether EPA has authority to regulate greenhouse gases under the Clean Air Act, and if they do, to what extent," Palmer said.

In April, EPA announced that U.S. greenhouse gas emissions rose 3.2 percent in 2010 from the previous year due to economic growth and higher electricity demand from high summer temperatures. However, in 2010, the U.S. emitted 5.3 percent fewer greenhouse gases than in 2005. The power sector accounts for 40 percent of the nation's greenhouse gas emissions.

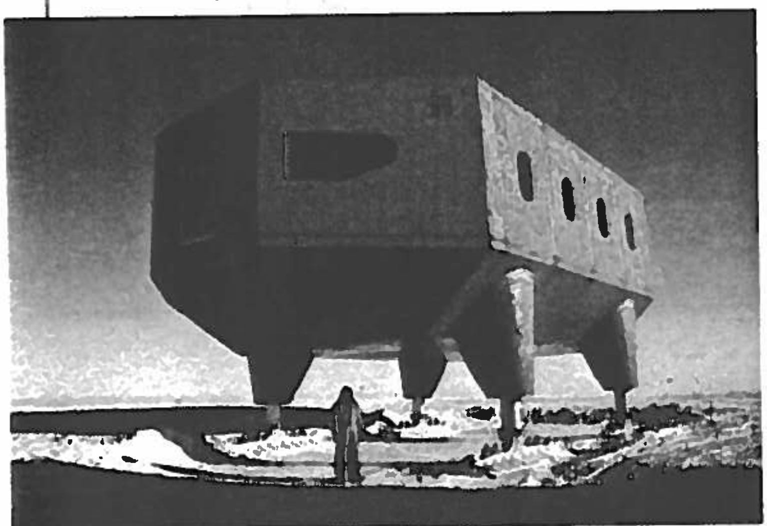
EPA is seeking additional comment and information, including public hearings, and will take that input into account as it completes the rulemaking process. EPA's comment period will be open for 60 days following publication in the Federal Register. A final rule is expected to be released later this year, most likely after the November elections. pe

Bowman Heat Exchangers More Than A Match For The Antarctic Winter

By Jamie Pratt, Sales Manager, EJ Bowman

Heat exchangers used in the new British Antarctic Survey (BAS) research station have survived 'years of freezing conditions' in the world's harshest climate to provide much needed heat for the new Halley VI research station.

The heat exchangers are helping to provide the 'green' power to the station, which is currently under construction on the Brunt Ice Shelf, Antarctica. Due to be commissioned in 2012, personnel from BAS and the main contractor, Galliford Try, had returned to the station in January 2011 to tow



all of the modules to the Halley VI site, link them up and raise them to their operational height, to test the generators and to complete as much as possible of the internals.

The BAS blog reported: "After several years of storage in freezing conditions, the main contractor, Galliford Try, was keen to test all the generators to make sure they still worked and to give confidence they will start when commissioning begins. All four generators were first checked by setting them up and dry firing them. Then they were tested and analysed under load. Thankfully they all passed with the minimal of works required."

In a new update in mid August 2011, the sun had returned to the Antarctic, allowing BAS construction staff to check that the modules had survived the harsh Antarctic winter with no problems and that the combined heat and power system, of which Bowman heat exchangers are a vital part, was fully operational and performing to the required standards.

Halley VI is the UK's most isolated research facility and will house laboratories and living accommodation for BAS scientists. In winter, temperatures plunge to - 500C, snow falls for half the year and gales can last for 40 days. The Bowman heat exchangers are a vital part of the combined heat and power system (CHP) that supplies constant and reliable energy for space heating, hot water, lighting, ventilation and electrical power. Without this CHP system, the resident BAS team who live and work at the base could not survive.

Designed by Westac Power, the CHP system makes use of waste heat to warm the buildings and melt snow to provide water. The Bowman heat-exchangers capture the waste heat from the engines exhaust and cooling systems, which would otherwise escape to atmosphere. This process allows the CHP system to provide heating and hot water at no additional cost in terms of fuel usage or emissions to the environment. In fact, the heat exchangers are so efficient they can reclaim up to 60 percent of all lost heat from the engines, enabling a diesel powered Genset to achieve total energy efficiencies of up to 90 percent.

EJ Bowman supplied heat exchangers for a combined heat and power system for the British Antarctic Survey's new Halley VI station (pictured) on the Brunt Ice Shelf, Antarctic. Photos courtesy EJ Bowman.

With an estimated fuel demand of 240 cubic meters per year to keep the station operational, reducing energy consumption and emissions was critical in the design of the power system. The heat exchangers help lower the cost of operation by reducing energy consumption which in turn, results in savings in the use of fuel and fuel shipment costs to the station.

EJ Bowman manufactures a comprehensive range of heat exchangers for use in combined heat and power applications, including sustainable heating and power generation applications. pe