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Another issue that utilities will potentially face in the near future is the need to reduce CO_2 emissions. The existing coal-fired fleet in the U.S. is responsible for about one-third of all of the CO_2 emissions. While automobiles and other industries make up a large portion of U.S. CO_2 emissions, coal-fired power plants are an easier target to identify, measure, and control. Due to its high overall efficiency, repowering an existing coal-fired power plant with IGCC can reduce CO_2 emissions by as much as 20%.

Overall, repowering with IGCC provides a utility with significant increases in environmental performance. By reducing SO_2 and NOx emissions, minimizing solid waste disposal issues, and addressing potential near-term emission limitations for mercury and CO_2, repowering with IGCC allows the utility to move forward with the knowledge that it has addressed environmental issues effectively. For capacity additions and repowering over the next five years, IGCC is an option that utilities can seriously consider.

IGCC Power Plant Applications

Recent History and Applications

Coal gasification technology has been used for over a hundred years. The production of town gas worldwide is a simple form of gasification. Coupling this proven technology with efficient combined cycle technology was seen as a way to enjoy the advantages of using low-cost coal with the high efficiency of combined cycle technology. The 100-MW Cool Water IGCC project, which went in service in 1984, was the first commercial-scale demonstration of IGCC. That project was done in a consortium of EPRI, Southern California Edison, Texaco, GE, Bechtel, and others. The plant operated for more than four years, achieving good performance, low emissions, and developing a base of design for full-scale IGCC plants.

Since then, IGCC technology has improved greatly through DOE's Clean Coal Technology program. The Wabash River IGCC Project and Polk Power Station IGCC Project are in operation as a part of this program. Installations in other countries include the Buggenum plant in the Netherlands and the Puertollano plant in Spain. IGCC performance and reliability continues to see significant improvements. In the fourth year of operation of Tampa Electric's Polk Power Station, the gasifier had an on-stream factor of almost 80%, a considerable improvement over previous years. This project no longer suffers from the serious problems encountered over the first three years, including convective syngas cooler pluggage, piping erosion and corrosion, and sulfur removal problems. The on-going pluggage problems in the convective syngas coolers have been resolved by modifying start-up procedures to minimize sticky ash deposits, and by making configuration changes in the inlet to the coolers to reduce ash impingement at the tube inlets. In the fourth year, the coal gasification portion of the plant became so reliable that the leading cause of unplanned downtime was not there, but rather in the distillate oil system for the gas turbine (problem has been addressed).

Reliable performance has also been achieved at the Wabash River plant. During 2000, the gasification plant reached 92.5% availability, with the power block at 95%. In fact, the gasification technology caused no plant downtime at all. Other areas of the plant, such as coal handling and the air separation unit were available more than 98% of the time.

IGCC for New and Repowered Plants

These examples show that IGCC has met the challenges of the Clean Coal Technology program. Further, with almost 4,000 MW of IGCC in operation worldwide, and another 3,000 MW planned to go into

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operation over the next four years, this technology is commercially proven and ready for the repowering market.

The U.S. now has about 320,000 MW of coal-fired power plants, just over one-third of all installed capacity. These coal-fired power plants generate over half of all of the electricity in the U.S. Many of these plants are over 30 years old, with some over 50 years of age. With a growing need for additional capacity in many parts of the country, and rising operation and maintenance costs on existing units, many utilities are looking hard at repowering with technologies that can increase capacity, while decreasing operation and maintenance costs.

Repowering with IGCC can meet those challenges. Repowering older, less efficient generating units with IGCC, results in capacity increases, lower production costs, higher efficiency, and environmental compliance. Since the IGCC plant uses coal as its feedstock, much of the existing coal-fired plant's coal handling and steam turbine equipment and infrastructure can be utilized, lowering the overall cost of repowering. With greater than 95% of the sulfur emissions removed, and further improvements in combustion turbine low-NOx burner technology, emissions of SO_2 and NOx now approach the performance of NGCC plants. By using low-cost and/or low-quality coals, the cost of electricity generated from a plant repowered with IGCC technology can meet or beat that produced by NGCC plants.

One of the key efficiency advantages comes with oxygen-blown IGCC technology. In this type of gasification system, air is first separated into its main constituents: oxygen and nitrogen. The oxygen is used in the gasifier, and the nitrogen is injected into the gas turbine, where it increases the mass flow through the gas turbine, increasing power output, and minimizing NOx formation during combustion. Efficiency increases through further integration can be realized by using extraction air from the gas turbine in other areas of the plant. Since this extraction air leaves the gas turbine at high temperature and pressure, it can be used to preheat boiler feed water. After the heat is removed, the cooled air, still at high pressure, is used to feed the air separation unit, reducing the amount of energy expended there to compress air.

A typical method of repowering an existing unit is to remove the coal-fired boiler and replace it with a gas turbine, re-using the steam turbine in combined cycle mode. In a combined cycle plant, the steam turbine usually provides about one-third of the total output. In a recent study conducted for DOE, a large number of plants with twin 150 MW units were identified as good candidates for repowering. There, the utility could repower one of the units with two 170 MW natural gas-fired gas turbines. The steam produced by the HRSGs for these units would power the existing 150 MW steam turbine, for a total of almost 400 MW.

A typical F class gas turbine produces about 170 MW when firing natural gas. At high ambient temperatures, output may fall to only 150 MW. In an IGCC plant, the syngas is fired in the gas turbine along with the nitrogen, providing significantly higher overall mass flow over a wide range of ambient temperatures. When firing syngas, this same F class gas turbine produces about 20% more output, reaching 190 MW or more. This additional capacity from firing syngas is valuable when additional peaking power is needed during hot, summer days. The additional exhaust flow results in more steam production in the HRSG, making up for steam uses in the gasification area. By firing syngas, the overall capacity is increased to almost 550 MW, more than tripling the capacity of the unit. Repowering the twin 150-MW unit could increase the overall capacity from the original 300 MW to almost 1,100 MW.

While the typical repowering study targets coal-fired boilers, existing NGCC units also provide a technical and economic opportunity for repowering with IGCC. In the case of NGCC units presently firing natural gas, rising fuel costs have lead to increases in the cost of producing electricity. This

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typically results in a lower capacity factor, and the unit generates fewer MW-hours and revenues. Given the inherent high efficiency of the gas turbines, and the ability to utilize low-cost coal, repowering with IGCC can turn an NGCC unit with a high dispatch price into a unit that dispatches at a much lower cost. As described above, the additional 20% capacity gained from firing syngas instead of natural gas can have significant economic value in areas where there is insufficient peaking power capacity.

IGCC technology has become a more attractive option for new capacity because:

- the technology has been successfully demonstrated at commercial scale in the U.S. and worldwide;
- the enhancements made by the companies operating these IGCC plants, as well as by the technology suppliers, have decreased the cost and complexity of IGCC, while at the same time substantially improving the efficiency and reliability; and
- the price differential between natural gas and coal has risen sharply over the last year.

Economics

The ability to repower units and gain the capacity increases noted in the previous section is a major economic driver for repowering with IGCC. Another advantage of repowering with IGCC is the ability to reuse a significant amount of the existing infrastructure at the plant. Areas such as buildings, coal unloading, coal handling, plant water systems, condenser cooling water, transmission lines, and substation equipment can be incorporated into the repowered IGCC plant This helps to minimize the time for repowering and can reduce the overall cost by about 20%.

With uncertainty in the pace and extent of utility industry restructuring, as well as with changes in environmental regulations, utilities have been reluctant to make large capital expenditures for new capacity. Almost all of the capacity installed over the last few years has been natural gas-fired gas turbines and NGCC. With ongoing decreases in the cost per kW for NGCC technology, along with forecasts of low natural gas prices, NGCC has been the choice for almost all of the new planned baseload capacity in the U.S. Most of this new generation has been built and is being planned in states that have completed their electric utility industry restructuring, making for easier entry into power markets. Unfortunately, the greatest needs for new generation have been in California and the Southeast where deregulation has either been incomplete, inconsistent, or delayed.

With recent increases in the price of natural gas, and stability or even decreases in coal costs, the electric utility industry has renewed its interest in coal-based technologies. Announcements by Tucson Electric Power and Wisconsin Electric Power to build the first coal-fired power plants in years puts coal back in the picture for new capacity. One important result of the improved performance of existing IGCC plants has been an overall decrease in second-generation IGCC plant capital costs. If the current differential price between coal and natural gas continues or grows larger, the economics for repowering with IGCC will become even more attractive.

In the paper "EPRI Analysis of Innovative Fossil Fuel Cycles Incorporating CO_2 Removal," various power generation technologies were analyzed with and without CO_2 removal systems, in a study performed by Parsons. The allowable capital costs were analyzed to determine a break-even cost of electricity based on a range of gas prices. For IGCC, the break-even point with $5/mmBtu gas was found to be about $1,200/kW, dropping to about $1,000/kW with $4/mmBtu gas prices. As IGCC plant costs continue to decrease, it will become an even more serious choice for repowering. If CO_2 removal is required in the future, the costs shown in the study for CO_2 removal and the cost of producing electricity from IGCC will be competitive with NGCC at gas prices of only $3.70-4.00/mmBtu.

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Reducing Regulatory Barriers

The Clean Air Act ("CAA") imposes a number of regulatory burdens on the expansion of electric generating capacity. EPA's recent interpretations of several existing laws have led to confusion and perhaps additional burdens. Formally proposed EPA revisions to existing CAA programs may impose further burdens if they are adopted. These burdens impact three activities that increase U.S. generating capacity: (1) the construction of new units; (2) efficiency and availability improvements at existing units; and (3) the repowering or reactivation of existing units.

New Construction

The CAA provides two main programs to control emissions from new coal-fired sources: New Source Performance Standards ("NSPS") and New Source Review ("NSR"). Both programs are intended to require the adoption of controls at the time it is most economical to do so – when a new unit is designed and built.

A utility wishing to construct a new coal-fired generating station must comply with NSPS. NSPS require new sources to meet numerical emissions limitations based on the best technology that EPA determines has been "adequately demonstrated." EPA revises these standards periodically to reflect advances in emissions control technology.

In areas that are in attainment with National Ambient Air Quality Standards ("NAAQS"), a new major source also must comply with prevention of significant deterioration ("PSD") requirements. PSD rules require new sources to adopt the "best available control technology" ("BACT") and to undergo extensive pre-construction permitting. This includes air quality modeling and up to one year of air quality monitoring to determine the impact of the new source on air quality. EPA or state permitting authorities determine what type of control constitutes BACT on a case-by-case basis. BACT may require control beyond NSPS for that source category, but may not be less stringent than applicable NSPS.

A company that constructs a new major source near a "Class I" attainment area must satisfy additional requirements. Class I areas include most national parks, and federal land managers ("FLMs") are charged with protecting air quality in these areas. PSD rules require that FLMs receive copies of PSD permit applications that may impact air quality in Class I areas. In cases where the new source will not contribute to emissions increases beyond allowable levels for the attainment area (*i.e.*, beyond the PSD "increment" for that area), the FLM may still object to issuance of the permit based on a finding that construction of the source will adversely impact "air quality related values" ("AQRVs") (including visibility) for that area. The FLM bears the burden of making that adverse impact demonstration. If the state concurs with the determination, then a permit will not be issued. In cases where the new source would contribute to emissions beyond the PSD increment, the company must satisfy both the FLM and the permitting authority that the unit will not adversely impact any AQRVs, before the permit may be issued.

A company that constructs a new major source in a nonattainment area must satisfy NSR requirements similar to, but more stringent than, PSD requirements. Instead of adopting BACT, the source must adopt control as needed to meet the Lowest Achievable Emission Rate ("LAER") for that source category. LAER is based on the most stringent emissions limitation found in the state implementation plan ("SIP") of any state, or the most stringent emission limitation achieved in practice in the source category, whichever is more stringent. A new major source in a

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nonattainment area also must demonstrate that any new emissions caused by the source will be offset by greater emissions reductions elsewhere.

In July 1996, EPA proposed changes to these new source programs that would increase the burdens on the construction of new generating stations. EPA's proposal would give FLMs the authority to require companies to perform AQRV analyses even where their new units would not cause exceedence of the PSD increment. A company's PSD application would not be considered complete until it had completed these analyses. EPA's proposal also would transfer authority from EPA to FLMs to define AQRVs and determine what qualifies as an "adverse impact" on those values. These changes, as a whole, would increase the ability of FLMs to control the timing and eventual issuance of PSD permits. EPA also would require state and federal permitting authorities to adopt a "top down" method for determining BACT. Under this method, a PSD applicant must adopt as BACT the most stringent control available for a similar source or source category, unless it can demonstrate that such level of control is technically or economically infeasible. The effect of the policy is to make BACT more similar to LAER in the stringency of control required. The proposed rule is now under review by the Bush EPA.

Following another recent EPA determination, new sources may be required to meet technology-based emission limitations for mercury and other air toxics. On December 20, 2000, EPA indicated that it would regulate emissions of mercury and possibly other air toxics from coal- and oil-fired utilities under the CAA's maximum achievable control technology ("MACT") program. Depending on the basis for the determination, state and federal permitting authorities may be required to impose unit-specific MACT limits on new coal- and oil-fired units until a categorical federal standard is promulgated in 2004. As its name implies, MACT would require units to meet a numerical emissions limitation consistent with the use of the maximum control technology achievable for regulated pollutants.

New source permitting is a lengthy process. The permit must be issued within one year of the filing of a "complete" application. Developing a "complete" application, however, can take another year or longer, as a source negotiates with the permitting authority, FLM, and others regarding modeling, monitoring, control technology, AQRVs, and other issues. If the proposed revisions to the NSR rules are finalized and if case-by-case MACT determinations are required, this permitting process for new sources will take even longer. Even without these proposed revisions, it will be important to consider how this permitting process can be streamlined and expedited.

Efficiency/Availability Improvements at Existing Units

Utilities have many opportunities to increase electrical output at existing units without increasing fuel burn by improving efficiency or reducing forced outages through component replacement and proper maintenance. In some cases, utilities do so as a reaction to unexpected component failures (reactive replacement). In others, utilities replace worn or aging components that are expected to fail in the future or whose performance is deteriorating (predictive replacement). In some cases, utilities replace components because more advanced designs are available and would improve operating characteristics at the unit. Such component replacement can restore a unit's original design efficiency or, in some cases, improve efficiency beyond original design.

Babcock & Wilcox ("B&W"), industry experts on the construction, operation, and maintenance of coal-fired boilers, identify a number of components that electric generating stations typically replace or upgrade during their service lives to maintain or improve operations. These include

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economizers, reheaters, superheaters, furnace walls, burner headers and throats, and other assorted miscellaneous tubing. In their book Steam, the B&W authors identify predictable ages for the failure of these components and offer a variety of upgrade options to be incorporated as replacement parts. Other components that utilities frequently replace or upgrade include fans, turbine blades and rotors, feed pumps, and waterwalls.

NSR rules apply to "modifications" of existing facilities that result in new, unaccounted for pollution. For the first 20 years of these programs, EPA identified only a handful of "modifications." In 1999, however, EPA sued several major utility companies for past availability and efficiency improvement projects like those described above, characterizing them as modifications subject to NSPS and NSR. EPA has further indicated that it will treat innovative component upgrades that increase efficiency or reliability without increasing a unit's pollution-producing capacity as modifications as well. EPA's current approach to these projects strongly discourages utilities from undertaking them, due to the significant permitting delay and expense involved, along with the retrofit of expensive emission controls that are intended for new facilities. This is the greatest current barrier to increased efficiency at existing units.

NSR rules define a modification as a physical change or change in the method of operation that results in a significant increase in annual emissions of a regulated pollutant. However, the rules exclude activities associated with normal source operation from the definition of a physical or operational change, including both "routine maintenance, repair, and replacement" and increases in the production rate or hours of operation.

For more than a decade following the establishment of these programs, EPA made very few determinations that projects triggered NSR as "modifications." These determinations involved sources that: (1) added new capacity beyond original construction, for example by adding an entirely new generating unit; or (2) reactivated a long-shutdown unit.

In 1988, EPA concluded that a collection of component replacements intended to extend the lives of five Wisconsin Electric Power ("WEPCo") generating units that had been formally derated and were at the end of their useful lives triggered NSR. Pointing to the project's "massive scope," unusually high cost ($80 million spent on five 80-MW units) and "unprecedented" nature, EPA concluded that the project was not "routine," and calculated an emissions increase for purposes of NSR.

Following the WEPCo decision, utility companies and the Department of Energy asked EPA to clarify the impact of its ruling for common component replacement projects in the industry. Through a series of communications with Congress and the General Accounting Office, EPA assured utilities that "WEPCo's life extension project is not typical of the majority of utility life extension projects, and concerns that the agency will broadly apply the ruling it applied to WEPCo's project are unfounded."

In 1992, EPA issued regulations that confirm the historical meaning of the modification rule and provide special guidance on the application of the rule to electric utilities. Under the 1980 rules, the method used to determine an emissions increase for NSR purposes depends on whether a unit is deemed to have "begun normal operations." The preamble to the 1992 rule states that units are deemed not to have begun normal operations only when they are "reconstructed" or replaced with an entirely new generating unit. Units deemed not to have begun normal operations must measure an emissions increase by comparing pre-change actual emissions to *potential* emissions after a change. Since few facilities operate at full capacity around the clock before a change, this test – if applied to existing sources -- nearly always shows an apparent emissions increase (even where

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emissions in fact decline after the change). Sources that have begun normal operations may compare actual emissions before the change to a projection of actual emissions after it. For utilities, the 1992 rule allows a comparison of past actual to "future representative actual emissions," a term defined to allow elimination of projected increases in utilization due to demand growth and other independent factors (provided that post-change utilization confirms the projections). Other units make a more generic comparison of pre- and post-project emissions holding production rates and hours of operation constant.

In the decade following the WEPCo decision, utilities continued to undertake the replacements described above without incident. In November 1999, however, EPA commenced a major PSD enforcement initiative against seven utility companies and the Tennessee Valley Authority alleging violations of PSD provisions. In complaints and notices of violation ("NOVs"), EPA alleged that replacements of deteriorated components undertaken at these units over the past 20 years were non-routine and triggered emissions increases under NSR rules. The complaints and NOVs target component replacements common in the industry, including economizers, superheaters, reheaters, air heaters, feedwater pumps, burners, turbine blades and rotors, furnace and water wall sections, and other components. EPA has since expanded the enforcement initiative to cover more than 20 companies, with plans to add more.

EPA's claim that these projects are now non-routine has left utilities highly uncertain about the coverage of the modification rule. In particular, EPA now suggests that it has discretion to classify projects as non-routine for several new reasons, including the fact that the replacement restores availability, improves efficiency, or involves a major component. At the same time, EPA has raised the stakes for a finding that a project is non-routine by assuming an emissions increase from all non-routine projects. Specifically, in contrast to the NSR rule, EPA now asserts that any non-routine change makes a unit into one that has not "begun normal operations" – necessitating use of an "actual to potential" emissions increase test that the unit is sure to fail. This is true even where such units have an extensive past operating history that would allow reliable predictions of future actual emissions.

A utility considering projects similar to those targeted in the complaints and NOVs must confront the fact that EPA has claimed broad discretion to classify availability and efficiency improvement projects as non-routine modifications subject to NSR. NSR requires the retrofit of BACT technology, which can cost hundreds of millions of dollars, and can delay projects by several years while permits are obtained and/or controls installed. Accordingly, EPA's actions strongly discourage utilities from undertaking projects that improve efficiency, and thereby increase generation without any increase in pollution.

B&W's Steam suggests the scope of projects blocked by EPA's current approach to modification. In order to reach a standard 55 to 65 year operating life, B&W estimates that a typical utility will replace its superheaters and burners at least twice, its reheaters at least once or twice, the economizer and lower furnace at least once, and all other tubing at least three times. Turbine blades are replaced more frequently still. Industry-wide, this means thousands of major component replacements may be prevented or delayed by EPA's approach, as well as other categories of projects EPA has not yet addressed but may find non-routine under its new discretion.

Moreover, EPA has extended its approach to innovative component upgrades that improve unit efficiency and other operating characteristics. In a letter dated May 23, 2000, EPA concluded that a plan by the Detroit Edison Company to replace worn turbine blades with new, improved blades was non-routine. Detroit Edison proposed to replace existing blading with a new, more durable

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blading configuration that would increase the efficiency of two turbines by 4.5% each. This would allow these units each to produce 70 additional megawatts of power with no increase in fuel consumption, or to continue producing at past energy levels while reducing fuel consumption by 112,635 tons of coal per year, SO_2 emissions by 1,826 tons per year ("tpy"), and NO_x emissions by 1,402 tpy. This would also allow an incidental 259,111 tpy reduction in CO_2 emissions – a compound that EPA currently lacks authority to control. The company estimated that widespread adoption of the upgrade at compatible units would allow CO_2 reductions of approximately 81 million tpy, with correspondingly large reductions in NO_x and SO_2. EPA based its finding of non-routineness in part on the fact that the project made use of new, upgraded component designs. EPA reached a similar conclusion in 1998, finding that a proposed blade replacement project at a Sunflower Corporation power plant could not be routine because it involved redesigned/ upgrad[ed]" components. Accordingly, utilities contemplating innovative upgrades of turbine and other components to improve efficiency face a known risk that EPA will classify them as non-routine modifications based on their use of advanced technology. Although the exact numbers of innovative projects blocked by EPA's approach is difficult to quantify, the example of Detroit Edison suggests that the losses in generation and pollution reduction from these efficiency gains is substantial.

In sum, EPA's new approach to its NSR rules presents a significant regulatory barrier to projects at existing sources that would otherwise be undertaken to improve availability and efficiency. This barrier can be expected not only to prevent significant gains in generating capacity at existing units, but also to actively reduce availability of these units by preventing needed maintenance. As a related matter, this barrier also can be expected to inhibit development of more efficient generating technologies, reducing the amount of energy that may be produced from existing units, and to encourage prolonged reliance on units operating at lower efficiencies.

Repowering and Reactivation

Replacing a coal-fired boiler with a more efficient generating technology, such as fluidized bed combustion, or an integrated gasification combined cycle, or state-of-the-art pulverized coal technology, can increase generation at an existing facility. This process is commonly known as "repowering." Title IV of the CAA grants special treatment to utilities that meet the acid rain requirements of that title through repowering. A project that qualifies as "repowering" for Title IV purposes also gains exemption from NSPS requirements if the project does not increase the unit's maximum achievable hourly emissions. Such projects almost certainly require PSD review, but are granted expedited review under the Act. EPA has yet to implement these expedited review procedures. Additional uncertainties for permitting these facilities are created by EPA's proposal to "reform" the new source permitting process discussed above.

Reactivation of shutdown existing units presents another means for utility companies to increase generation. A source that has been shutdown for an extended period may be subject to NSPS and/or NSR when it is reactivated. Early determinations on this topic are often unclear or inconsistent as to whether the reactivated unit is subject to NSPS or NSR because it is deemed to be a new unit, or because it is deemed to be an existing unit that has undergone a "modification." In its most recent determination on the subject, EPA has suggested that a unit could be subject to NSPS/NSR for either reason – making for a stricter, two-part standard. Clarification of EPA's reactivation policy, and streamlining of NSR requirements for reactivated facilities, would contribute capacity needed to respond to demand peaks.

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Solutions

EPA's proposed rule on NSR would impose significant additional burdens for new sources if it is finalized in its current form. EPA's recent listing of coal- and oil-fired electric utility steam generating units as major sources of hazardous air pollutants could require additional, extended pre-construction review for new and reconstructed facilities. EPA's recent reinterpretation of the modification rule with respect to routine repair and replacement, calculating emissions increases, and source reactivation imposes additional burdens that discourage projects that increase unit availability and efficiency or reactivate shutdown units, including cases where shutdown was never intended to be permanent. EPA should return to its historic interpretation and application of these rules.