Opportunities to Expedite the Construction of New Coal-Based Power Plants

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U.S. DEPARTMENT OF ENERGY

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OPPORTUNITIES TO EXPEDITE THE CONSTRUCTION OF NEW COAL-BASED POWER PLANTS

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Preface

The National Coal Council is a private, nonprofit advisory body, chartered under the Federal Advisory Committee Act.

The mission of the Council is purely advisory: to provide guidance and recommendations as requested by the U.S. Secretary of Energy on general policy matters relating to coal. The National Coal Council is forbidden by law from engaging in lobbying or other such activities. The National Coal Council receives no funds or financial assistance from the Federal Government. It relies solely on the voluntary contributions of members to support its activities.

The members of The National Coal Council are appointed by the Secretary of Energy for their knowledge, expertise and stature in their respective fields of endeavor. They reflect a wide geographic area of the U.S. and a broad spectrum of diverse interests from business, industry and other groups, such as:

- large and small coal producers;
- coal users such as electric utilities and industrial users;
- rail, waterways, and trucking industries as well as port authorities;
- academia;
- research organizations;
- industrial equipment manufacturers;
- state government, including governors, lieutenant governors, legislators, and public utility commissioners;
- consumer groups, including special women's organizations;
- consultants from scientific, technical, general business, and financial specialty areas;
- attorneys;
- state and regional special interest groups; and
- Native American tribes.

The National Coal Council provides advice to the Secretary of Energy in the form of reports on subjects requested by the Secretary and at no cost to the Federal Government.

Abbreviations

AEO	Annual Energy Outlook
AFBC	Atmospheric fluidized bed combustion
AMM	Abandoned mine methane
API	American Petroleum Institute
ABCT	Best available control technology
Bcf	Billion cubic feet
Btu	British thermal units
Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CBM	Coalbed methane
CCS	CO_2 capture and storage
CCT	Clean Coal Technology
CDM	Clean Development Mechanism
CFB	Circulating fluidized bed
CMM	Coal mine methane
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
DOE	Department of Energy
DSM	Demand side management
EEI	Edison Electric Institute
EHE	External heat exchanger
EIA	Energy Information Administration
EIIP	Emission Inventory Improvement Program
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FBC	Fluidized bed combustor
FE	Fossil energy
FGD	Flue gas desulfurization
FY	Fiscal year
GCCI	Global Climate Change Initiative
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatts
GWP	Global warming potential
H_2	Hydrogen
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
JI	Joint implementation
KW	Kilowatt
kWh	Kilowatt-hour
lb/MBtu	Pounds of emissions per million Btu of heat input
lb/MWh	Pounds of emissions per megawatt-hour generated
LHV	Lower heating value
LNB	Low NO_x burners
LNG	Liquified natural gas
MBtu	Million Btu
MMTCE	Million metric tons carbon

$MTCO_2$	Million tons of carbon dioxide
MW	Megawatts
MWh	Megawatt-hour
N_2O	Nitrous oxide
NCC	National Coal Council
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NMA	National Mining Association
NO_x	Nitrogen oxides
NSR	New Source Review
O&M	Operating and maintenance
PC	Pulverized coal
PFBC	Pressurized fluidized bed combustion
PFBCwTC	Pressurized fluidized bed combustion with topping combustor
PPM	Parts per million
PPMV	Parts per million by volume
PSI	Pounds per square inch
R&D	Research and development
RD&D	Research, Development and deployment
SC	Supercritical
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TPY	Tons per year
UNFCCC	United Nations Framework Convention on Climate Change
USC	Ultra-supercritical
VAC	Ventilation air methane
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

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Executive Summary

Purpose

By letter dated December 3, 2003 (see Appendix E), U.S. Secretary of Energy Spencer Abraham requested that The National Coal Council prepare a study identifying "which opportunities could expedite the construction of new coal-fired electricity generation." He also requested that the Council "examine opportunities and incentives for additional emissions reduction including evaluating and replacing the oldest portion of our coal-fired power plant fleet with more efficient and lower emitting coal-fired plants."

The Secretary expressed his belief that this report "will serve as a blueprint for industry while acting as a guide to promote the construction of new coal-fired facilities."

The Council accepted the Secretary's request and formed a study group of experts in the field to conduct the work and prepare a report. The list of participants on this group can be found in Appendix D of this report.

Findings

The National Coal Council finds the following. Each finding is of equal importance.

Coal is the fuel of choice now, and will remain so into the future.

Coal-based power plants produce greater than 50% of all the electricity in the United States. It will remain the primary fuel source for electricity generation for the foreseeable future. It is secure, affordable and environmentally compatible. The country has about 250 years of supply in reserve at the present rate of consumption. Through continued research, development and deployment of new technologies, coal will continue to fuel low-cost electricity and to demonstrate continued environmental improvements.

Natural gas has been the dominant fuel for new power plants in the last decade.

Over the past decade, the availability of low cost natural gas and increased competition in the electric generation market, when combined with certain federal energy polices of the 1990s promoting the use of natural gas, has resulted in the choice of natural gas over coal as the fuel for most new generating plants. The net effect of the 1990s policies was to stimulate natural gas demand through its use to generate electricity to the detriment of American citizens who use it for home heating purposes and industries which rely on natural gas for their primary feedstock or other uses.

Coal provides a pathway for greater energy independence.

As the demand for electricity continues to increase, the Energy Information Administration (EIA) and others have forecasted large increases in electricity generation using natural gas as a fuel. With the United States' best prospect for increasing natural gas supplies coming from foreign sources including Canadian imports and liquefied natural gas (LNG), a better alternative for energy independence would be to build more new, domestically supplied coal-based power plants.

There is renewed interest in using coal to fuel new power plants.

Increases in the price and historical volatility of natural gas supplies, the long-term stability of coal prices, and the financial impacts from a number of financially distressed investments in natural-gas combined-cycle power plants have led to a renewed interest in coal-based electricity generation. Forecasts of natural gas supplies and prices have become more accurate. Supply difficulty and price volatility that have occurred since 2000 and the revised estimates of natural gas reserves by some companies have resulted in more realistic assessments of natural gas supplies and a more reasoned projection of natural gas prices. The National Petroleum Council's 1999 and 2003 reports provide good examples of this increasing accuracy. The higher price forecasts and other warnings in turn make the economic models used to support natural gas-based power plants less attractive.

Generators are expected to remain credit worthy.

Experts in the financial community believe that the outlook for investor-owned electric utilities (IOUs), rural electric cooperative and municipal generators (gencos), and independent generation companies, diversified energy merchants and energy traders, is generally stable. While many IOUs and gencos have either maintained creditworthiness or are well on their way to financial recovery, the investment community believes that many in the merchant or independent power sectors will need time to recover. There are structural differences between the various power producers, and financial issues that impact decisions about whether or not to construct new coal-based facilities differ between the segments.

Permitting delays have been an impediment to building new coal plants.

The length of permitting time, as well as redundant permitting requirements, has created impediments to new construction. These delays are a result of an inefficient permitting process – including a lengthy permitting appeals process – that can delay plants to the point of causing plant cancellations. Even with new coal-based generation meeting, and in some cases exceeding, the most stringent emissions control requirements and efficiency standards, the time from project initiation to start-up is routinely extended due to delays in the permitting process that do not result in any changes to the plant's emissions control systems. These delays result in increased costs and cause uncertainty in the investment community (with higher perceived risks related to developing new coal-based plants).

Environmental regulatory approaches have been an impediment to building new coal plants.

Over the past three decades, the prevailing environmental regulatory approaches have led to the retrofit of high capital cost emissions control technologies at existing coal-based generating plants. In order to avoid the risk of stranded investments and the uncertainty of investing in new plants, power plant operators have taken steps to extend the lives of existing plants. This has also made it more difficult for new plants to enter the electricity market at a price competitive with the overall cost of electricity from older, coal-based plants where the capital cost component of electricity is much less.

Uncertainty about CO_2 emission reductions has been an impediment to the construction of new coal-based power plants.

The uncertainty of future environmental regulations, especially associated with CO_2, has complicated decisions about whether or not to repower or replace existing coal-based generation. This situation is exacerbated by the uncertainty surrounding the broader issue of carbon management.

Incentives are still needed to facilitate the construction of advanced coal-based power plants.

Past incentives have facilitated research, development and demonstration of advanced, clean and efficient coal-based technologies leading to significant advancements in both environmental performance and generation efficiency. However, these technologies require additional support for deployment to achieve significant market penetration.

Lack of a regional planning approach has been an impediment to the construction of new coal-based power plants.

The transitional state-by-state changes in the electric utility industry have resulted in a lack of regional planning. This lack of regional planning has resulted in a short-term focus with small, incremental capacity additions such as natural gas combined cycle plants, rather than coal-based plants that provide enhanced energy security, long-term sustainability and lower overall electricity prices for our nation.

Infrastructure hurdles are impediments to the construction of new coal-based power plants.

Opportunities to install new coal-based power plants in both the short term and in the future are inhibited by several factors that warrant attention on a national environmental and energy policy basis. These factors include the continued failure of the Federal Energy Regulatory Commission (FERC) and the states to deal with transmission congestion, declining engineering resources in the United States, limited availability of skilled construction labor to build new coal-based power plants, declining manufacturing infrastructure in the United States for the fabrication of steel and steel components required for new coal plants, and growing regulatory hurdles to permit and construct new coal mines.

Recommendations

The National Coal Council makes the following recommendations:

Streamline the permitting process.

The Department of Energy, in concert with other appropriate agencies and stakeholders, should develop an integrated, flexible and streamlined approach to environmental regulations and permitting for new, advanced coal-based generation. Operating permits issued under this approach should include assurances that new regulations will not change the permit for a certain fixed period of time after the start-up of the new plant. The Department of Energy (DOE) should then work with the U.S. Environmental Protection Agency (EPA) and others to implement this approach. The goal is to encourage the development and deployment of a domestic, reliable, clean and affordable energy supply. This approach will create incentives and certainty for investments in advanced coal-based generation, while allowing appropriate time for capital stock turnover.

Recognize the strategic importance of integrated gasification combined cycle (IGCC) technology.

The Department of Energy, in concert with other agencies, should create incentives that recognize and reward the potential for integrated gasification combined cycle to replace the use of natural gas in the electricity generation market, produce synthetic gas for poly-generation, and to accelerate progress of the Hydrogen Initiative. This would help stabilize the price of natural gas and free more of it for use in the chemicals, fuels and fertilizer industries, thereby saving domestic jobs in those industries. Also, coal gasification could provide additional feedstock for these industries at a competitive cost.

Recognize the importance of other coal-based technologies.

While IGCC technology is strategically important to the future of coal, the Department of Energy should also support R&D for other advanced coal-based technologies, including advanced pulverized coal-based technology and circulating fluidized bed technology, especially in the areas of carbon capture and ultra-supercritical designs and other efficiency improvements, so that investors in coal-based power plants can choose from a portfolio of attractive technologies.

Encourage regional planning.

The Department of Energy should explore the viability of and encourage a regional planning approach for capacity additions. The regional approach should consider a mechanism to reward investment in efficient and environmentally superior coal-based plants that would have widespread regional benefits and transcend the individual territory of any one state or IOU.

Continue with meaningful R&D.

The Department of Energy should continue research and development work on advanced, efficient and lower-emitting coal-based technologies to ensure that technology continues to keep pace with the goals set forth in the DOE/CURC/EPRI Roadmap. In addition, this effort should include adequate funding and support for flagship programs such as FutureGen and the Hydrogen Initiative.

Continue with technology demonstration.

The Department of Energy should ensure that proper mechanisms and incentives are in place to allow not-yet-mature and first-of-a-kind technologies to be demonstrated in the marketplace so that promising coal-based technologies can be ready for wide-scale deployment through programs such as the Clean Coal Power Initiative.

Provide meaningful incentives for the commercialization and deployment of new advanced coal-based technologies.

The Department of Energy should develop incentives to overcome the risk-adjusted cost differential between options of conventional technologies and new, more efficient, lower-emitting advanced coal-based plants so that these advanced plants can be more expeditiously deployed in the marketplace. The menu available for such incentives includes, but is not limited to, tax incentives, production incentives, public/private cost-sharing, accelerated depreciation, loan guarantees, and federal credit.

Maintain a balanced portfolio of Research & Development, Demonstration and Deployment.

The Department of Energy should recognize the importance of properly funding Research & Development, Demonstration and Deployment and must ensure that proper funding is allocated to all three elements of technology development.

Work with state regulators for cost recovery of new advanced coal-based plants.

The Department of Energy should facilitate the development of a clear regulatory mechanism that will allow investors to recover added costs of replacing some of the older, less efficient existing power plants with new advanced coal-based power plants. Innovative cost recovery proposals should address both state and regional concerns. Additional vehicles could be developed to insure recovery of new capital investment as well as any stranded capital from un-recovered investments associated with the retirement of older facilities. This mechanism would have the opportunity to provide a new incentive to facilitate the construction of new coal-fueled power plants with minimal impact on the federal deficit.

Continue to be a champion for coal.

The Department of Energy should continue to strongly reinforce as often as possible that coal is a vital resource for our country. Coal must be utilized to provide an adequate measure of energy security and reliability, and it has been and will continue to be the major fuel for electricity generation in the country. The use of coal should be encouraged as an alternative feedstock for chemicals and fuels (especially those that are imported), and appropriate incentives and regulatory approaches should be provided to encourage its use in as clean a manner as possible. The use of clean coal technologies should be fostered, encouraged and promoted in other countries where coal is a vital resource. Ever-changing environmental regulations create an impediment to new coal plants. Investment in new plants involves hundreds of millions of dollars and the investment community needs clear and stable rules as a foundation for that investment. Regulations can be and are reinterpreted over time. Stability can only be achieved through legislation.

Section 2: Technology Choices and Economics

Overview

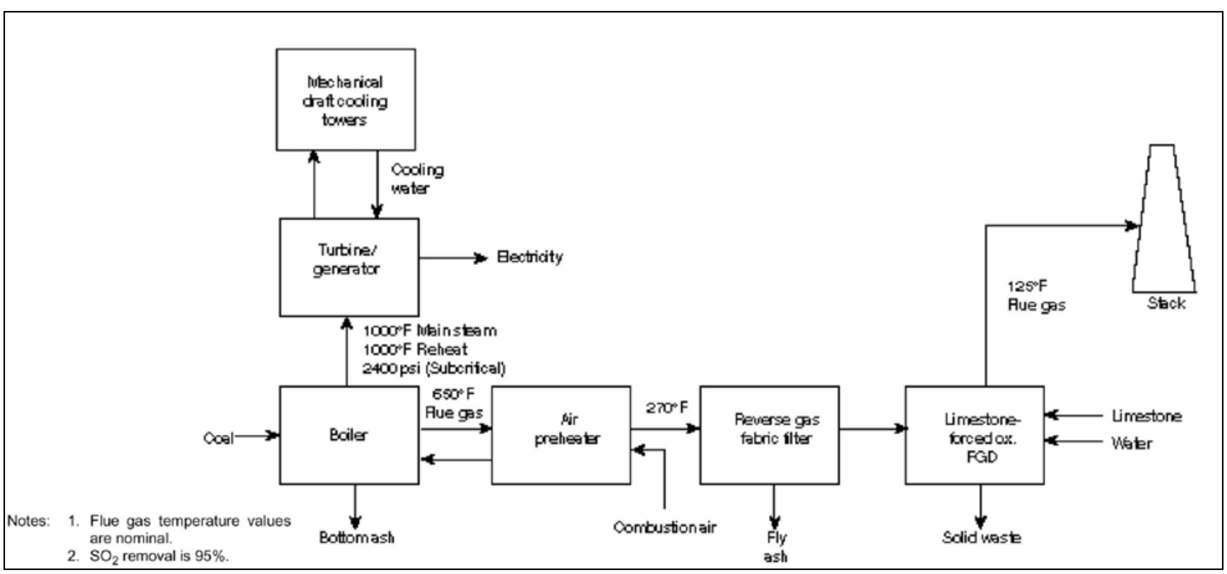
This section of the report provides technical descriptions of the primary types of coal-based technologies being considered for new power plants, focusing on comparisons of their performance, efficiency, and cost. In addition, descriptions of emission control technologies and their impacts on unit cost and performance are discussed. Utilizing this information on performance and cost, the results of an economic case study that compares a range of power generation technologies are provided. This information can be used by plant developers to compare the various technologies, along with their relative capital and O&M costs, environmental performance, heat rate and overall cost of electricity (COE).

Coal-Based Technology Descriptions

Pulverized Coal (PC)

PC plants have continued to develop over the last decade. In the U.S., most have utilized standard, subcritical operating conditions at 2,400 psig/1,000°F superheated steam, with a single reheat to 1,000°F. A typical PC plant is shown in Figure 2.1. Since the early 1980s, there have been significant improvements in materials for boilers and steam turbines and a much better understanding of the cycle water chemistry. These improvements have resulted in an increased number of new plants employing supercritical (SC) steam cycles around the world. SC units typically operate at 3,600 psig, with 1,050-1,100°F main steam and reheat steam temperatures. On the average, these SC units have efficiencies of about 3 percentage points higher than subcritical units, representing an 8% relative improvement in efficiency. Steam temperatures above 1,050°F are often referred to as ultra-supercritical (USC) conditions.

Figure 2.1
PC Block Flow Diagram (Subcritical, Wet Limestone Forced Oxidation FGD)



Over the past 10 years, significant improvements have also been achieved in reducing heat losses in the low pressure end of steam turbines, improving both efficiency and reliability of the overall generating units.

PC plants have been the workhorse of America's coal-based power plant fleet for decades.

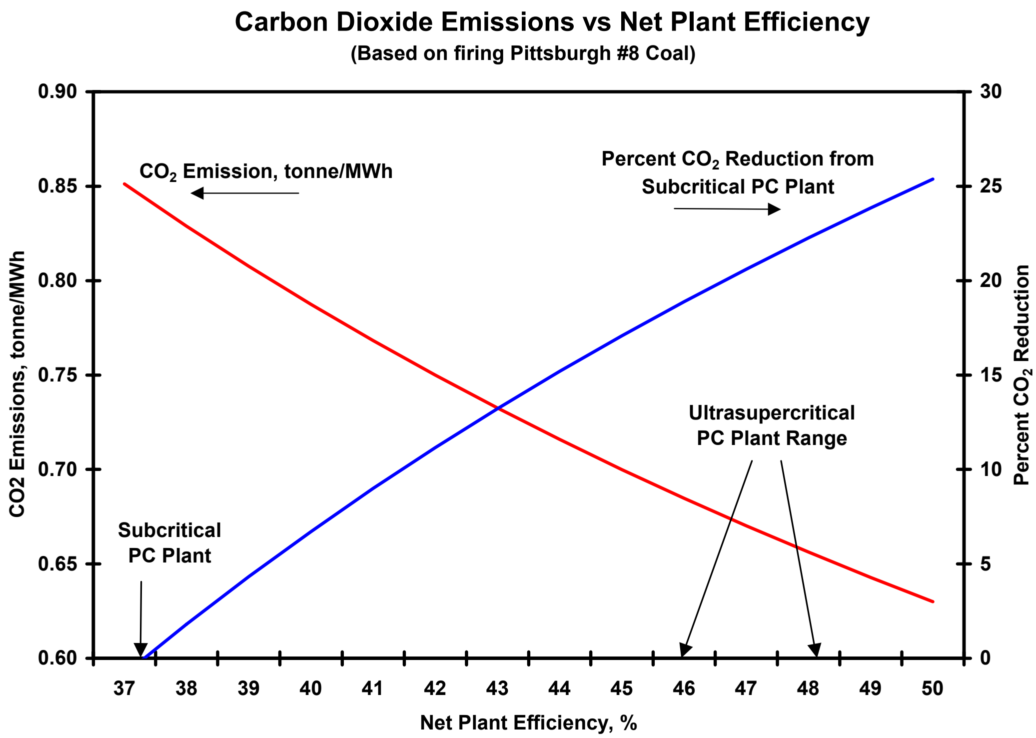
The choice of subcritical cycles for the coal-based power plants that have been built in the U.S. in the last 20 years has been mainly due to relatively low fuel costs. This has eliminated the cost justification for higher capital costs for higher efficiency cycles, such as SC. In international markets, where fuel cost is a higher fraction of the total COE, the higher efficiency cycles offer advantages which can result in favorable COE comparisons and lower emissions compared to subcritical plants. Of the more than 500 SC units in the world, 46% are in the former USSR, 12% are in Europe, and 10% are in Japan. Almost one-third of SC units are in the U.S.; and all of these U.S. units were built prior to 1991. None have been built since, although one has been announced for a plant in the Midwest. There is considerable activity with new SC units in Europe and Asia.

The selection of SC versus a subcritical cycle is still dependent on many other site-specific factors, including fuel cost, emission control requirements, capital cost, load factor, local labor rates and expected reliability and availability. With the extensive favorable experience in Europe and Asia with SC steam cycles during the last decade, their superior environmental performance and the relatively small cost difference between SC and subcritical plants, it is becoming more difficult to justify new subcritical steam plants.

While improvements in boiler and turbine materials and designs have resulted in higher efficiency and availability, the continued addition/retrofit of emission control systems to meet progressively stringent emission standards has had a significant impact on unit performance and cost. Most new PC units utilize flue gas desulfurization (FGD) systems based on wet limestone scrubbing with forced oxidation (LSFO), in order to control SO_2 emissions. With more than 25 years of full-scale commercial implementation of this technology, it has become much more reliable and far less costly. Still, only about one-third of existing coal-based units have FGD systems. Combustion modifications for the reduction of NO_x emissions from existing units have been widely implemented, primarily due to the acid rain provisions of the Clean Air Act Amendments of 1990. Low-NO_x burners developed as part of the Department of Energy's Clean Coal Technology demonstration program in the 1990s have been retrofitted in many units across the country. The retrofit of dozens of selective catalytic reduction (SCR) systems for post-combustion NO_x control resulted from EPA's State Implementation Plan call for NO_x reductions to reduce the interstate transport of NO_x, primarily in the eastern states. The performance of these emission control technologies has continued to improve. However, cost and performance impacts are significant. These impacts are discussed later in this section.

Potential reductions in greenhouse gas emissions, particularly for CO_2, have also gained significant attention. For coal-based technologies, one available option to reduce CO_2 emissions per unit of electricity generated is to increase the unit's efficiency, so that less coal is burned per MWh generated. Figure 2.2 shows the reduction in CO_2 emissions that could be achieved with increases in efficiency. These increases could be accomplished by retiring an older subcritical unit and replacing it with a more efficient boiler (i.e., SC or USC). For example, an advanced USC plant with an efficiency of 46-48% (HHV basis) would emit approximately 18-22% less CO_2 per MWh generated than an equivalent-sized subcritical PC unit. Of course, this reduction would also apply to emissions such as SO_2 and NO_x, since the more efficient plant would use less coal to produce the same energy. It is estimated that if the next 10 GW of coal-based plants were to be built using more efficient SC technology, CO_2 emissions would be about 100 million tons less during the lifetime of those plants, even without installing a system to remove the CO_2 from the exhaust gases.

Figure 2.2 Carbon Dioxide Emissions vs. Net Plant Efficiency



Fluidized-Bed Combustion (FBC)

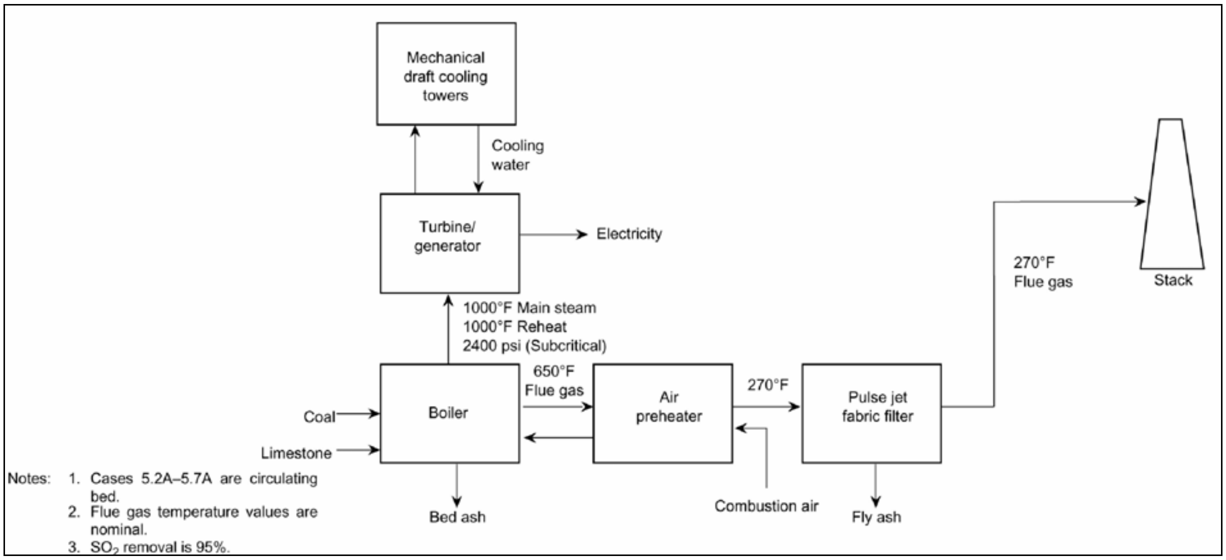
FBC technology has benefited greatly from incentives in the 1980s to assist in the commercial-ization of this clean coal technology.

In FBC units, coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air that is blown in from below through a series of nozzles. The fluidized bed of solids provides thermal "inertia" which moderates upsets due to sudden changes in fuel composition. More than 95% of the solids consist of sorbents capable of capturing the SO_2 released during the combustion of coal and inert coal ash. The coal and coal char constitute less than 5% of the bed solids.

A typical FBC plant is shown in Figure 2.3. Like conventional PC units, FBC units operate in a Rankine steam cycle, utilizing steam produced in a boiler to drive a steam turbine generator. FBC boilers operate at lower temperatures than PC boilers, and burn crushed fuel in a fluidized bed rather then pulverized fuel in a PC unit's furnace. The heat rates of FBC plants tend to be slightly higher than PC plants at the same plant size and steam conditions because of higher excess air and higher auxiliary power requirements. In general, FBC boilers burn coals with higher excess air (18-25% instead of 15-20% for PC), which results in higher flue gas heat loss. The higher pressure drop across the furnace requires more fan energy. However, the advantage of using FBC technology is that FBC boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_x formation, and capture SO_2 in-situ.

In addition, FBC boilers are capable of burning a range of fuels, including bituminous and sub-bituminous coals, coal waste, lignite, petroleum coke, and a variety of waste fuels or "opportunity" fuels like biomass that cannot be accommodated by PC units. In many instances, units are designed to use several fuels, emphasizing one of this technology's major advantages: its inherent fuel flexibility. FBC boilers also can readily handle many fuels that are problematic in PC boilers.

Figure 2.3 Fluidized-Bed Combustion Block Flow Diagram



The most common FBC designs employ a large hot cyclone between the furnace and the convective heat transfer sections to recirculate unreacted sorbent and unburned fuel back to the bed, where the remaining carbon can be burned and more SO_2 captured. These systems are called circulating fluidized-bed combustors (CFB). Due to superior mixing characteristics of CFBs compared to bubbling-bed FBCs, the excess air levels for CFBs are generally lower than for FBCs. Also, the higher sensible heat of the larger solid mass discharged and the higher pressure drop in the forced-draft fan in the FBC plants tend to make the heat rates for FBC inherently higher.

CFB operates at gas velocities high enough to entrain a large portion of the solids (12-30 ft/s), which then is separated from the flue gas and recycled (recirculated) to the lower furnace to achieve good carbon burnout and SO_2 sorbent utilization. Typically, an external hot cyclone is used at the furnace exit as a separation device. CFB recycle ratios usually exceed 40 lbs. of recycled solids per pound of feed solid, and may be much higher depending on the cyclone efficiency.

Because of the high recycle rate (high residence time) of unutilized sorbent and unburned carbon, CFB provides better SO_2 capture and better carbon burnout than bubbling bed (FBC) units. CFB also facilitates more effective air staging for improved NO_x control and is less prone to upsets due to fuel quality variation. Another important advantage of CFBs is that they require significantly fewer fuel and sorbent feed points compared to bubbling FBCs. This provides more simplified designs, better operational characteristics, and easier scale up to larger size units. Consequently, CFB is the predominant type of FBC boiler installed worldwide in unit sizes above 200,000 lbs. per hour of steam. Currently, the largest CFB unit in operation is 320 MW, but designs for units up to 600 MW have been developed by three of the major CFB suppliers. Some of these designs are based on SC steam conditions.

In-bed boiler tubes cannot be used in the CFB furnace because of severe tube erosion. However, an optional external bubbling fluidized bed can be employed as an external heat exchanger (EHE). In this unit, boiler tubes are immersed in a bed of the hot recirculating solids from the cyclone that are lightly fluidized by low-velocity secondary air. The cooler solids leaving the EHE are then recycled to the lower furnace. An EHE can take up a large fraction of the total heat duty in a large CFB unit, and therefore provides a flexible alternative to the need for additional in-furnace heat transfer surface in units larger than 40 MW. An EHE is also advantageous in conserving the furnace height in large CFB units and in optimizing reduced-load operation.

For SO_2 capture, limestone is fed into the fluidized bed in addition to the coal. The limestone is converted to free lime, a portion of which reacts with the SO_2 to form calcium sulfate. At steady-state operation, the bed consists of unburned fuel, limestone, free lime, calcium sulfate and ash. Because of the well-mixed nature of the bed and the relatively long residence time of the fuel particles (via high recycle rates in the CFB), efficient combustion can be maintained at temperatures as low as 1,550-1,650°F. This combustion temperature limits the formation of thermal NO_x and is the optimum temperature range for in-situ capture of SO_2 by the free lime. This temperature also prevents or reduces the slagging of coal ash on heat transfer surfaces.

In an FBC unit, SO_2 capture is a function of the limestone reactivity and Calcium-to-Sulfur (Ca/S) molar ratio, increasing in proportion to these parameters. As the sulfur content of the fuel increases, the Ca/S molar ratio required for a given percentage SO_2 reduction decreases because of the increased driving force (partial pressure) for the sorption process. For high-sulfur coals (> 2% S), Ca/S molar ratios of 2–2.5 are required to achieve 90% sulfur removal. For low-sulfur coals (< 1%), Ca/S molar ratios as high as 3–6 are required to achieve the same 90% sulfur removal. Recent CFB boiler designs include dry FGD systems to remove additional SO_2 at the back end and increase overall SO_2 capture to over 98%. Due to the high molar ratios of limestone required to capture and remove the SO_2, reagent and disposal costs are 50–100% higher than for PC plants with FGD systems using typical bituminous coals.

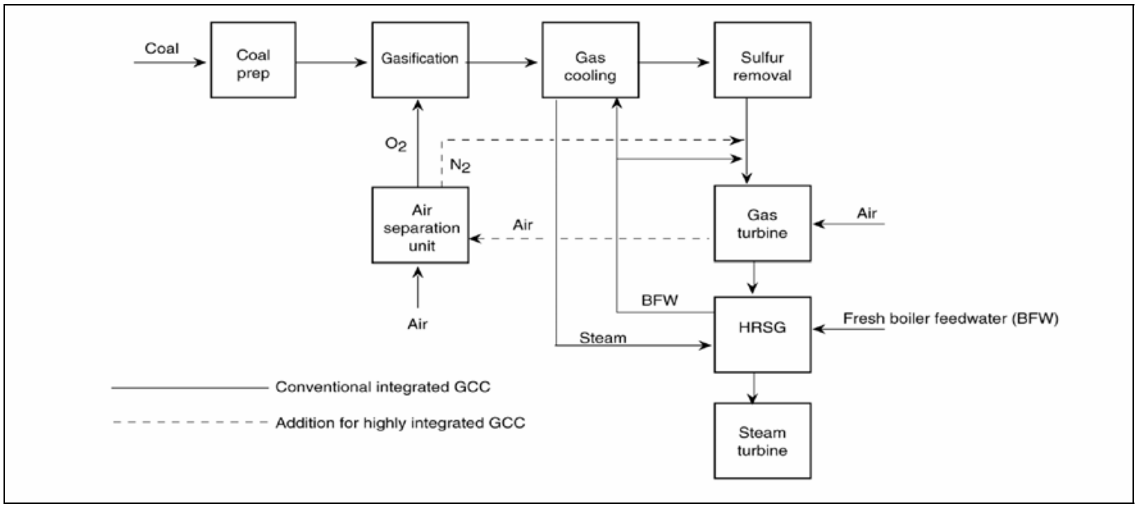
The environmental performance of FBC compared to PC boilers is enhanced by the inherently lower NO_x production due to the relatively low combustion temperatures of the FBC process. Staging the combustion air and decreasing the overall excess air level also reduces NO_x production. Emissions are typically in the range of 0.05–0.20 lb/MBtu without post-combustion NO_x controls, compared to 0.20–0.40 lb/MBtu for new PC boilers with the latest low-NO_x burners and over-fire air. The use of relatively inexpensive selective non-catalytic reduction (SNCR) systems with FBC can reduce the flue gas NO_x level an additional 50-90%, depending on ammonia slip and detached plume considerations. With a PC boiler, the more expensive SCR system would probably be required to achieve the same flue gas NO_x levels as FBC with SNCR.

However, the low combustion temperature does have some disadvantages. CFB boilers emit higher levels of N_2O, which forms and survives at temperatures below 2,000 °F. N_2O is a greenhouse gas with a Global Warming Potential 296 times that of CO_2. Because of its low concentration in the flue gas (typically in the range of 40-70 ppm at 3%O_2) this N_2O emission corresponds to an equivalent 15% increase in CO_2 emissions. A more detailed discussion of N_2O emissions from FBC has been presented in the May 2003 NCC Report "Coal Related Greenhouse Gas Management Issues".

Integrated Gasification Combined Cycle (IGCC)

IGCC allows the use of coal in a power plant with the environmental benefits of a natural gas-fueled plant and the thermal performance of a combined cycle. A block flow diagram of a non-integrated IGCC system is shown in Figure 2.4. In its simplest form, coal is gasified with either oxygen or air, and the resulting synthesis gas (or syngas), consisting primarily of hydrogen and carbon monoxide, is cooled, cleaned and fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators. By removing the emission-forming constituents from the syngas under pressure prior to combustion in the power block, an IGCC power plant can meet extremely stringent emission standards.

Figure 2.4
IGCC Block Flow Diagram



There are many variations on this basic IGCC scheme, especially in the degree of integration. It is the general consensus among IGCC plant designers today that the preferred design is one in which the air separation unit (ASU) derives part of its air supply from the gas turbine compressor and part from a separate air compressor. Since prior studies have generally concluded that 25-50% air integration is an optimum range, the case study in this section of the report has been developed on that basis.

Three major types of gasification systems are used today: moving bed, fluidized bed, and entrained flow. Pressurized gasification is preferred to avoid large auxiliary power losses for compression of the syngas. Most gasification processes currently in use or planned for IGCC applications are oxygen-blown instead of air-blown technology. This results in the production a higher heating value syngas. In addition, since the nitrogen has been removed from the gas stream in an oxygen-blown gasifier, a lower volume of syngas is produced, which results in a reduction in the size of the equipment. High-pressure, oxygen-blown gasification also provides advantages if CO_2 capture is to be considered at a later date.

IGCC plants have the advantage of very low emissions and high efficiency.

Entrained-flow gasifiers that deliberately operate in the higher-temperature slagging regions have been selected for the majority of IGCC project applications. These include the coal/water-slurry-fed processes of General Electric (formerly ChevronTexaco) and ConocoPhillips (formerly Dow/Destec E-Gas), and the dry-coal-fed Shell process. A major advantage of the high-temperature entrained-flow gasifiers is that they avoid tar formation and its related problems. The high reaction rate also allows single gasifiers to be built with large gas outputs sufficient to fuel large commercial gas turbines. Recent studies have shown that a spare gasifier can significantly improve the availability of an IGCC plant.

Most of the large components of an IGCC plant (such as the cryogenic cold box for the ASU, the gasifier, the syngas coolers, the gas turbine and the HRSG sections) can be shop-fabricated and transported to the site. The construction/installation time is estimated to be about the same (three years) as for a comparably-sized PC plant.

IGCC provides several environmental benefits over PC units. Since gasification operates in a low-oxygen environment (unlike PC, which is oxygen-rich for combustion), the sulfur in the fuel converts to hydrogen sulfide (H_2S), instead of SO_2. The H_2S can be more easily captured and removed than SO_2. Removal rates of 99% and higher are common using technologies proven in the petrochemical industry.

Due to its high flame temperature, combustion of the syngas in a gas turbine can result in high NO_x emissions in the exhaust gas unless controlled by other means. IGCC units can be configured to operate at very low NO_x emissions without the need for SCR. Two main techniques are used to lower the flame temperature for NO_x control in IGCC systems. One is to saturate the syngas with steam or hot water and the other is to use nitrogen from the ASU as a diluting agent in the combustor. Application of both methods in an optimized combination has been found to provide a significant reduction in NO_x formation. NO_x emissions typically fall in the 15 ppmv (at 15% O_2) range, just above those from natural gas combined cycle (NGCC) units, and when converted to a 3% O_2 basis, are similar to those from PC boilers.

An advantage of adding the extra mass from the steam, hot water or nitrogen into the gas turbine is that additional power is generated in the gas turbine and steam cycle. The type of gas turbine largely determines the electric output of an IGCC plant. The GE 7FA gas turbines used in the case study presented in this report have a nominal output of 197 MW in an IGCC application.

The basic IGCC concept was first successfully demonstrated at commercial scale at the pioneer Cool Water Project in Southern California from 1984 to 1989. There are currently two commercially sized, coal-based IGCC plants in the U.S. and two in Europe. The two projects in the U.S. were supported initially under the Department of Energy's Clean Coal Technology demonstration program, but are now operating commercially.

The 262 MW Wabash River IGCC repowering project in Indiana started up in October 1995 and uses the E-Gas gasification technology (which was acquired by ConocoPhillips in 2003). The 250 MW Tampa Electric Company Polk Power Station IGCC project in Florida started up in September 1996 and is based on GE (formerly ChevronTexaco) gasification technology. The first of the European IGCC plants was the NUON (formerly SEP/Demkolec) project in Buggenum, the Netherlands, using Shell gasification technology. It began operation in early 1994. The second European project, the ELCOGAS project in Puertollano, Spain, uses the Prenflo (Krupp-Uhde) gasification technology and started coal-based operations in early 1998. In 2002, Shell and Krupp-Uhde announced that henceforth their technologies would be merged and marketed as the Shell gasification technology.

The Wabash River and Polk IGCC plants represent the cleanest coal-based power technologies that exist today, and the current state-of-the-art facilities have even superior performance. A PC plant with emission controls may approach IGCC's performance in one or two areas, but does not match IGCC's lower overall environmental impact including air, water, and solids emissions. A state-of-the-art IGCC with enhanced sulfur removal technology can simultaneously achieve greater than 99.5% sulfur removal, essentially total volatile mercury removal (greater than 90-95% removal), and PM levels of <0.004 lb/MBtu. The state-of-the art IGCC plant will also produce only 40% as many solid byproducts as PC units, and will use almost 40% less water.

Effects of Coal Quality on Coal-Based Power Generation Technologies

Coal characteristics can have a significant impact on the selection of the optimum technology.

Fuel type is an important criterion that must be considered when choosing a given technology. Theoretically, any of the advanced coal technologies can use bituminous, sub-bituminous, or lignite coals. However, the coal characteristics of the different ranks of coals significantly impact the design of the different technologies and have different impacts on capital costs and operating efficiencies. This section discusses the significant differences.

PC Plants

Coal properties affect PC plant heat rates and boiler size. High moisture and high ash contents reduce boiler efficiency. Concern over corrosion in the cold end of the air heater and downstream ductwork (due to condensation of SO_3 as sulfuric acid) sets a minimum value on the permissible boiler outlet temperature when higher sulfur coals are used, and thereby reduces the achievable boiler efficiency. Each 18°F increase in air heater exit temperature reduces heat rate by about 14 Btu/kWh, or approximately 2%. Lower air heater exit temperatures can typically be achieved in plants designed for higher-quality, lower sulfur coals, where SO_3 levels and their resulting dew points are much lower.

Higher ash, lower heating value and higher sulfur coals adversely impact PC plant costs and performance.

Coal ash constituents can have a major impact on boiler design and operation. PC boilers are designed to utilize coals with either low or high ash fusion temperatures. For low ash fusion temperatures, the ash constituents are in molten form (slag) at furnace temperatures ("wet-bottom boilers"). The molten slag must be cooled, usually in a water bath, then crushed and sluiced to disposal or for recovery as a by-product. When ash fusion temperatures are high, the bottom ash exits the bottom of the boiler in solid form ("dry bottom boilers"), where it enters a water bath and is crushed and sluiced to disposal or storage. Over the past 30 years, many boilers designed for high sulfur, low ash fusion coals have been converted to lower sulfur coals to meet Clean Air Act emission reduction requirements for SO_2. Many of these low sulfur coals also have high ash temperatures. In order to utilize these coals in wet bottom boilers, operators have installed fluxing systems, which add a small percentage of materials such as limestone and iron oxide, chemically changing the make-up of the ash enough to lower the ash fusion temperature and allow it to melt at furnace temperatures. Blending coals of various sulfur and ash contents has become commonplace in the industry as a way to optimize boiler performance and environmental compliance.

Many units have been converted from high-sulfur, eastern bituminous coals to low-sulfur, sub-bituminous coals, primarily from the Powder River Basin (PRB) region. Due to changes in moisture and volatile content, power plant operators have had to make significant expenditures in coal unloading, coal handling, fly ash collection and fire protection systems to be able to handle these dusty coals in a safe manner.

CFB Plants

CFB plants have demonstrated the ability to burn high ash, high slagging/fouling fuels that would be problematic in a PC boiler. The cost impact of designing a CFB boiler to burn a sub-bituminous coal or lignite compared to lower-moisture, lower-ash, and lower-alkaline bituminous coal is less for a CFB boiler than for a PC boiler. This is primarily because the PC furnace heat transfer area must be increased in order to reduce furnace exit gas temperature as the ash softening temperature drops and thereby prevents slagging of the convective pass. Sub-bituminous fuels and lignites generally have alkaline ashes with low ash softening temperatures, which require large PC furnaces. On the other hand, CFB furnace size is strictly defined by gas velocity. CFB size would be increased for sub-bituminous and lignite fuels, but only due to the increase in fuel moisture, resulting in a much smaller increase than for a PC furnace.

CFB Plants have more fuel flexibility and are well suited to burn low-rank coals such as lignite.

IGCC Plants

IGCC plants are proven to work very well with bituminous coal. It is important to recognize that different gasification technologies will likely be required for different types of coal such as lignite and sub-bituminous.

IGCC Plants are well suited for bituminous coals.

The entrained-flow gasifiers of GE, Shell and ConocoPhillips all perform better with lower ash, lower moisture bituminous coals. Although these entrained-flow gasifiers can process all ranks of coal, most existing commercial gasifiers tend to show an increase in cost or reduction in performance with low-rank and high-ash coals. Both the Wabash River and Polk Power Station IGCC plants were designed for bituminous coals and most IGCC studies have been based on using bituminous coals.

The relative feed rate is a function of the heating value of the feedstock, although it is exacerbated by the additional auxiliary power consumption due to increased oxygen usage and coal handling, preparation and feeding – all of these lead to higher heat rates. Gasifier efficiency decreases with decreasing coal rank and more of the coal's energy is in the sensible heat from the gasifier. That leads to higher steam production; however, less of the feedstock energy is available to the more efficient Brayton (gas turbine) cycle and the overall IGCC efficiency is reduced. (The higher steam generation is more than offset by the increased auxiliary power consumption with lower rank coals).

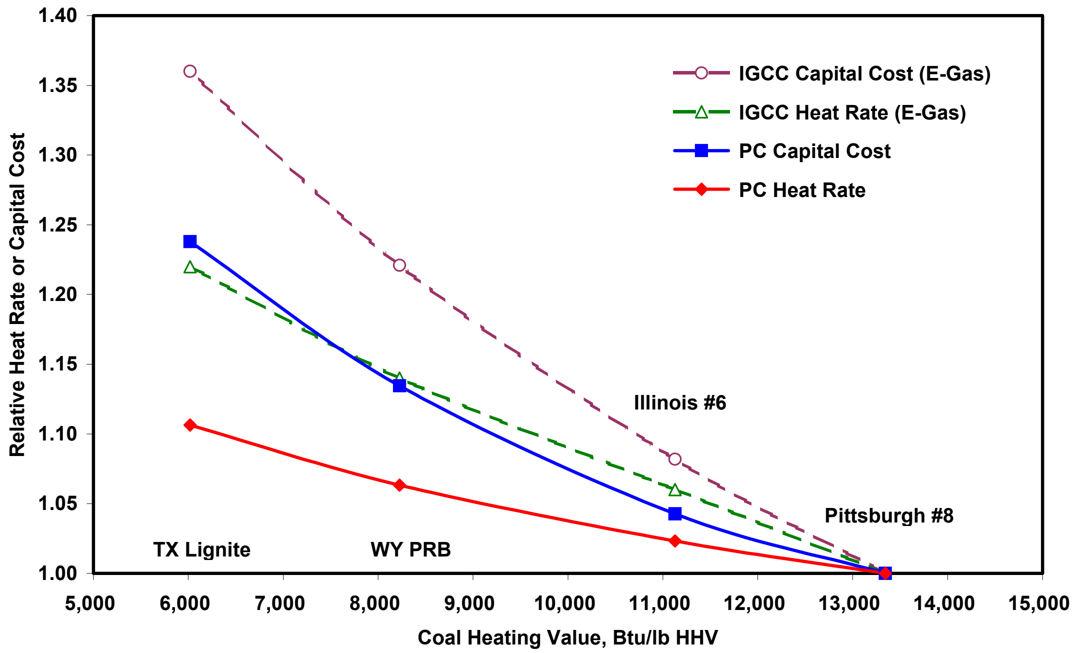
For slurry-fed gasifiers (GE and ConocoPhillips), the energy density slurries of high moisture and/or high ash coal is markedly reduced, which increases the oxygen consumption and reduces the gasification efficiency. Previous studies for E-Gas IGCC plants show a drop in performance and increase in capital costs as fuel quality is decreased from high quality (high carbon) feedstocks such as petroleum coke and Pittsburgh #8 coal to lower quality Illinois #6 and sub-bituminous coals and lignite. As the moisture content of the coal increases, the achievable solids concentration in the slurry becomes lower. Combined with the increased ash content in the lower rank coals, the energy density of the slurry deteriorates markedly. Accordingly, the relative oxygen requirement increases because more oxygen is required to evaporate the moisture.

Research suggests that dry-coal-fed gasifiers (Shell) are more appropriate for low-rank, high-ash coals. While studies show there is an energy penalty (and therefore reduced steam turbine output) for drying the high-moisture coals to the low moisture content necessary for reliable feeding via lock hoppers and pneumatic conveying, less expensive coal-drying techniques are now being developed with Department of Energy funding. In addition, more efficient and effective technologies have shown promising results with low-rank coals, such as the KBR transport gasifier being demonstrated at the Power Systems Development Facility, which receives funding from the Department of Energy, and was recently selected for funding under the DOE's Clean Coal Power Initiative.

Although IGCC is close to being competitive with PC for bituminous coals, gaps widen for the capital costs and COE between slurry-fed IGCC and PC for low rank coals to about $200-300/kW for PRB coal and approximately $400/kW for U.S. lignites. Previous studies by EPRI and others indicate the E-Gas IGCC plants do not appear to compete economically with PC plants when using PRB coals and lignites. Figure 2.5 shows the impact of coal rank, or coal heating value, on the relative heat rates and capital costs of PC plants and E-Gas IGCC plants. This illustrates the challenges of lower rank coals, particularly for slurry-fed gasifiers. This impact would be considerably less for dry-fed gasifiers.

Given the abundance and low cost of U.S. resources of low rank fuels such as Power River Basin sub-bituminous coals and Texas and North Dakota lignites, there is a great need to demonstrate and improve the performance of IGCC with these fuels.

Figure 2.5
Effect of Coal Quality on Heat Rate and Capital Cost



Economics of Power Generation Technologies

> **While representative capital costs are provided, capital cost estimates can vary widely depending on variable factors like plant location, size, coal properties and owner preference items.**

Figure 2.6 summarizes the results of an EPRI study which evaluated the performance, capital cost and COE for a range of 500 MW plants using various power generation technologies. The coal technologies for PC and IGCC applications are based on the use of a Pittsburgh #8 bituminous coal. The CFB case is based on the use of Illinois #6 bituminous coal.

The capital cost estimates shown in the figure represent average costs for each technology, based on EPRI's experience. Capital cost estimates can vary widely depending on such factors as plant location, size, coal properties, and owner preference items. Labor rates can vary by more than 30%, depending on plant location. The resulting total plant costs could vary by as much as 20-25%. The total plant cost (TPC) shown in the table includes engineering and contingency, and is also frequently referred to as the "EPC" cost. Total Capital Requirement (TCR) includes TPC plus other cost items such as interest during construction, start-up costs, working capital and land. Permits and other costs such as owner's engineering, project management, or legal expenses are project- and/or owner-specific and are not included in the TCR. IGCC projects typically include additional cost items in TCR, such as licensing fees, front-end engineering design (FEED) costs, and could also include higher financing costs due to the perception of greater risk. For this EPRI study, the additional costs included in TCR are about 16% of TPC for the PC plants, and nearly 19% is added to the TPC for IGCC plants.

The major components of the 500 MW PC units shown in Figure 2.6 include coal-handling equipment, the boiler island, turbine-generator island, FGD system, fabric filter, bottom ash and fly ash handling systems, and a wet stack with no flue gas reheat. The cost and design data include low-NO_x burners and SCR to reduce NO_x emissions to about 0.1 lb/MBtu for all cases.

The boiler island includes the coal pulverizers, burners, waterwall-lined furnace, superheater, reheater, economizer, soot blowers, regenerative air heater, and axial-flow forced- and induced-draft fans. For the subcritical unit shown in Figure 2.1**,** the steam conditions are 2,400 psig/1,000°F superheated steam, with a single reheat to 1,000°F. For the SC unit, the main steam pressure is 3,600 psig, with 1,100°F main and reheat steam temperatures.

The turbine-generator island includes the main, reheat and extraction steam piping, feedwater heaters, condenser, mechanical draft cooling towers, boiler feed pumps and auxiliary boiler. The steam turbine is a tandem-compound unit, designed for constant pressure operation with partial arc admission. The feedwater heating system uses two parallel trains of seven heaters, including the deaerator; the boiler feed pumps are turbine-driven. The condenser is designed to operate at 2.0 in. Hg back pressure.

An LSFO FGD system is required for medium- to high-sulfur coals (>2%). For this study, the LSFO FGD system utilizes one 100% module and no spare, which has become an industry standard for new units and for many retrofits. The design limestone feed rate is 1.05 moles $CaCO_3$/mole SO_2 removed, achieving 95% SO_2 removal. The flue gas enters the wet stack at about 125°F. The particulate collection system is a reverse-gas fabric filter, located ahead of the FGD system. Two 50%-sized fabric filter modules are connected in parallel.

Many assumptions go into the data used in the table on the next page. The assumptions used will drive the calculated COE, which drives the technology selection. In general, the cost of natural gas will be a primary driver on the economics of NGCC plants. The capital cost and capacity factor will be a primary driver on the economics of a coal plant.

Figure 2.6
Costs for 500 MW Power Plants Using a Range of Technologies

	PC Subcritical	PC Supercritical	CFB	IGCC (E-Gas) With Spare	IGCC (E-Gas) No Spare	NGCC 80% CF	NGCC 40% CF
Total Plant Cost, $/kW	1,230	1,290	1,290	1,350	1.250	440	440
Total Capital Requirement, $/kW	1,430	1,490	1,490	1,610	1,490	475	475
Fixed O&M, $/kW-yr	40.5	41.1	42.2	56.1	52.0	5.1	5.1
Variable O&M, $/MWh	1.7	1.6	4.0	0.9	0.9	2.1	2.1
Avg. Heat Rate, Btu/kWh (HHV)	9,310	8,690	9,800	8,630	8,630	7,200	7,200
Levelized Fuel Cost, $/MBtu (2003$)	1.50	1.50	1.00	1.50	1.50	5.00	5.00
Capital, $/MWh (Levelized)	25.0	26.1	26.1	28.1	26.0	8.4	16.9
O&M, $/MWh (Levelized)	7.5	7.5	10.1	8.9	8.3	2.9	3.6
Fuel, $/MWh (Levelized)	14.0	13.0	9.8	12.9	12.9	36.0	36.0
Levelized Total COE, $/MWh	46.5	46.6	46.0	49.9	47.2	47.3	56.5
1st Year COE, $/MWh	61.4	62.2	61.5	66.7	62.8	49.3	63.5

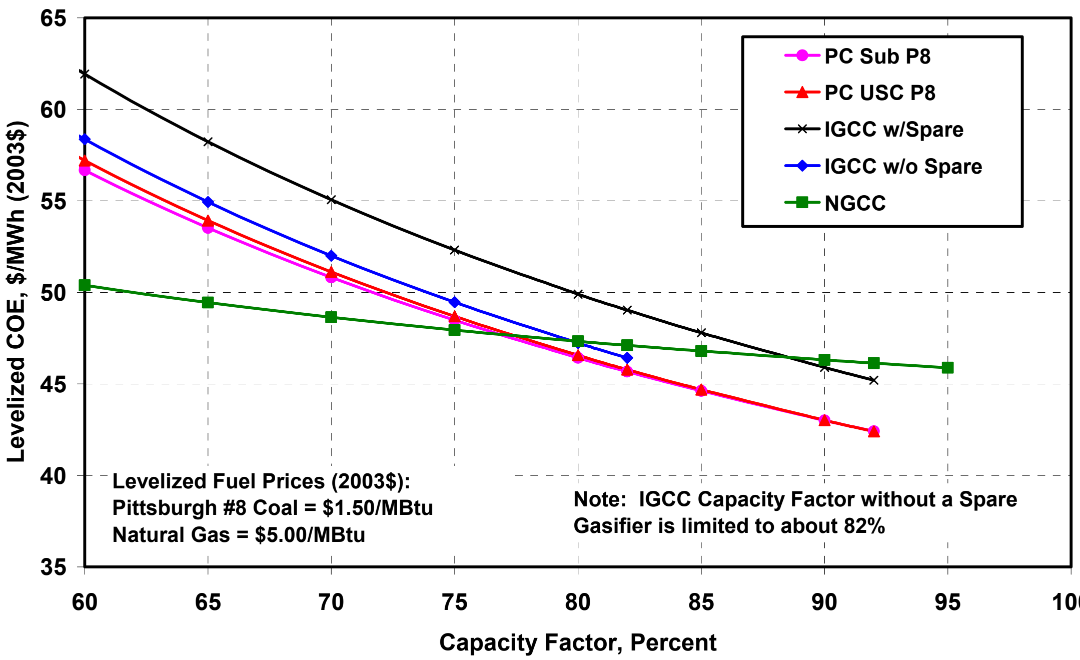
Other assumptions used to derive these results are as follows:

1. *Book life = 20 years*
2. *Commercial Operation Date = 2010*
3. *Total Plant Cost (TPC) includes Engineering and Contingencies*
4. *Total Capital Requirement (TCR) includes Interest During Construction and Owner's Costs (see text for details)*
5. *Assumes EPRI's TAG financial parameters*
6. *All costs expressed in 2003 dollars*

7. *COE is based on Levelized Constant Dollars and is calculated using the EPRI TAG Revenue Requirement Methodology*
8. *PC plants include FGD (95% SO_2 removal) and SCR (80% NO_x removal)*
9. *CFB plant includes 95% SO_2 removal (in-bed) and SNCR for NO_x reduction*
10. *IGCC includes syngas moisturization/nitrogen dilution to reduce NO_x to 15 ppmv*
11. *NGCC includes SCR to reduce NO_x to 3 ppmv*
12. *Capacity factor is 80% except as noted for the NGCC plants*

Plant capacity factor has a significant impact on the COE, especially for capital-intensive coal-based technologies. Figure 2.7 shows the impact of capacity factor on the constant-dollar, levelized COE for the bituminous coal-based technologies. The NGCC case from Figure 2.6 is included for comparison. A spare gasifier for the IGCC case would be necessary to achieve operation at over 85% capacity factor. IGCC plants without a spare gasifier are projected to have equivalent availabilities in the low 80's, whereas inclusion of a spare gasifier is expected to increase the IGCC plant equivalent availability to the low 90's. The coal-based technologies become preferred over NGCC at capacity factors over 78-80%.

Figure 2.7:
Impact of Capacity Factor on Levelized COE



Once the plant is built, coal-based power plants have a significant advantage in economic dispatch because coal is the least expensive fuel.

Another factor to consider in the trade-off of coal-based technologies versus NGCC is the fuel plus variable O&M cost, or dispatch cost. As shown in Figure 2.8, about 75% of the total levelized COE for an NGCC unit is due to fuel cost, whereas this drops to only about 30% for the coal-based technologies, as presented in Figure 2.9. This means that even though NGCC and coal may have the same total levelized COE, it is unlikely that the NGCC plant would dispatch before the coal plant, due to its higher fuel cost. Therefore it is unlikely that an NGCC plant would operate at anywhere close to 80% capacity factor. On that basis, coal would be the most cost-effective power generation technology. A recent EPRI report indicates that in 2003 the average capacity factor for NGCC plants was only 29%. With NGCC capacity factors less than half of those for coal plants, coal would be the most cost-effective choice for power generation technology.

Figure 2.8
Breakdown of Levelized COE for NGCC Plant

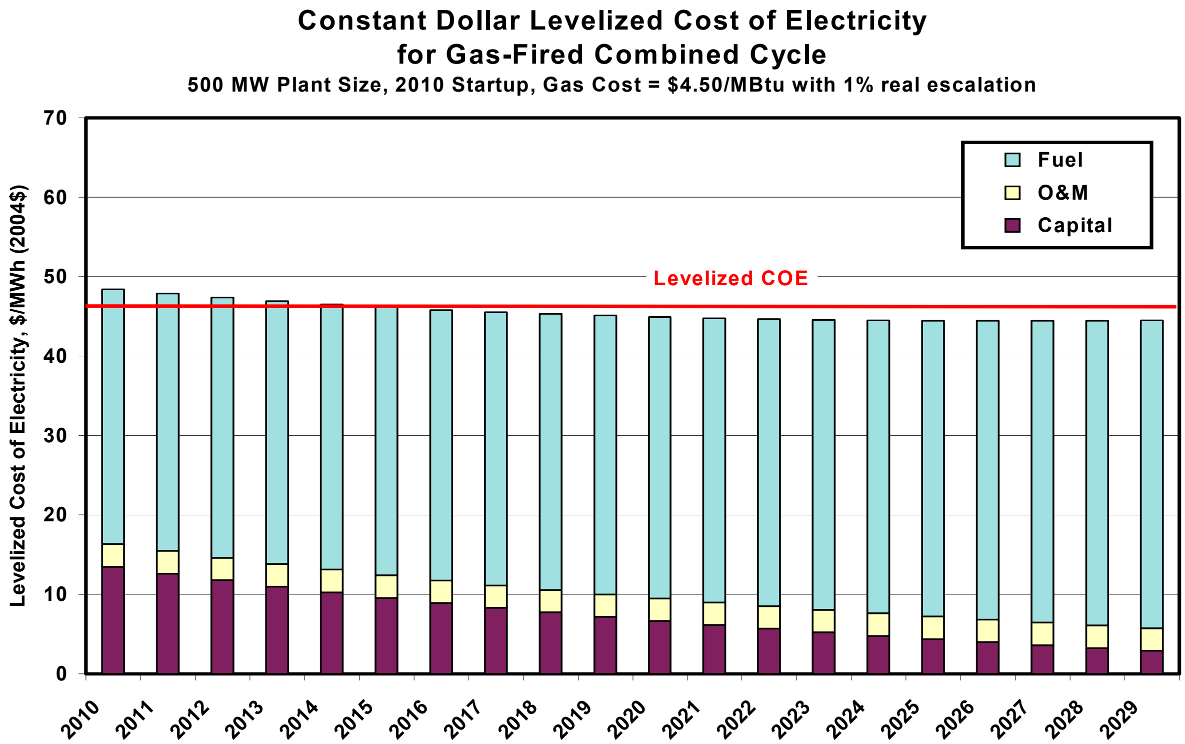
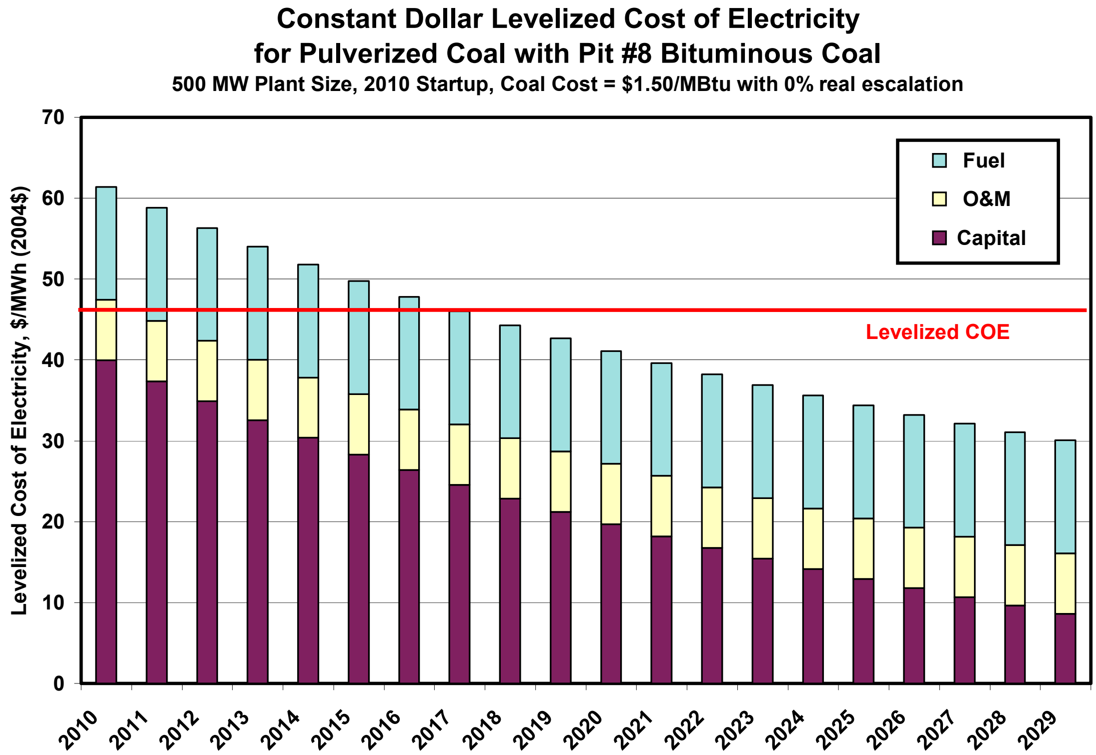
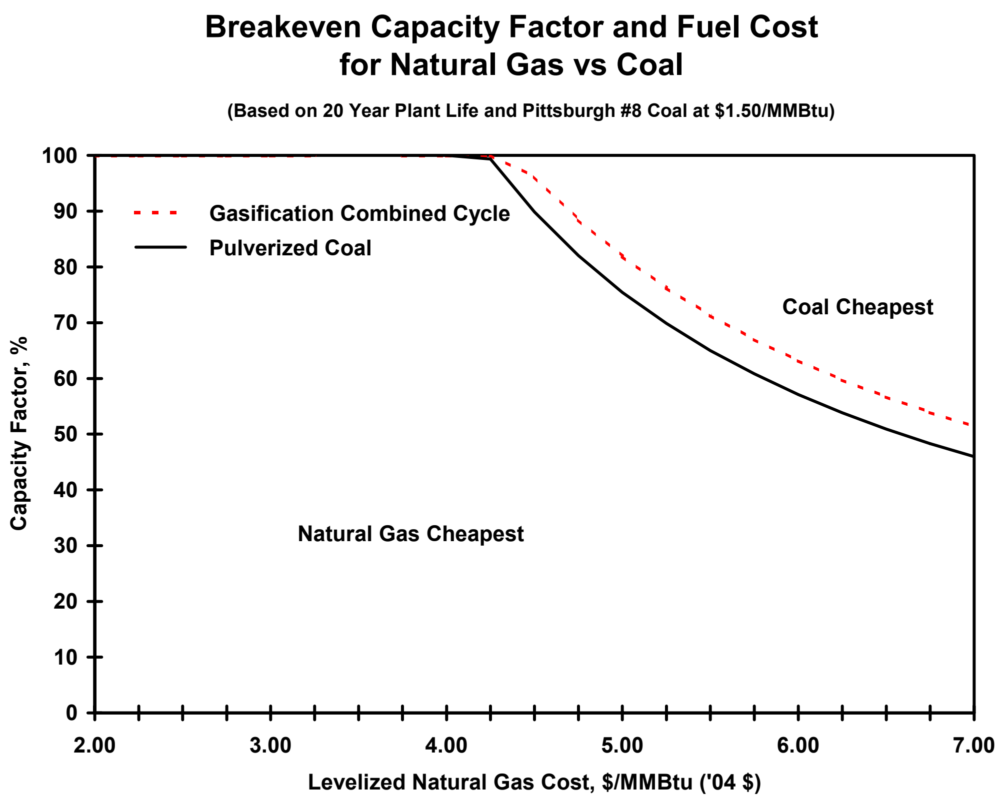


Figure 2.9 Breakdown of Levelized COE for PC Unit



Together, capacity factor and fuel cost can be analyzed to determine which fuel and technology will provide the lowest COE. Figure 2.10 compares PC and IGCC technologies (using Pittsburgh #8 coal at \$1.50/MBtu) with NGCC for a range of capacity factors and fuel costs. For high capacity factor (>80%) base load plants, coal-based electricity is cheaper than gas-based electricity when gas prices rise above \$4.75/mmBtu.

Figure 2.10



Air Emission Issues and Cost of Mitigation for Pulverized Coal Plants

The Clear Skies Act, the Interstate Air Quality Rule and other environmental control initiatives are being considered for adoption in the near future. If they go into effect, additional emission controls would need to be retrofitted on existing coal-based plants and would be mandatory for new units. This would result in lower overall efficiency and higher O&M costs.

EPRI recently completed a study to estimate the incremental costs for more stringent emission controls for PC plants fired with Eastern bituminous (Pittsburgh #8) and Western sub-bituminous (PRB) coals. In the study, emission controls for SO_2, NO_x and particulate matter (PM) were included. Incremental capital and O&M costs were developed for each 1% change in emission control. In addition, the levelized cost for each additional ton removed and the impact on levelized COE was calculated.

The study was based on a 500 MW subcritical PC plant located at a site in Wisconsin. Prior to retrofit, the plant had no FGD system. NO_x emissions were controlled by "typical" low NO_x burners and over-fire air, while particulates were controlled by an electrostatic precipitator.

SO_2 control technologies included a LSFO FGD system and a lime-based spray dry absorber (SDA) for sub-bituminous coal. For LSFO, the SO_2 removal range was 90-99%. For higher removal rates with LSFO, the scrubber liquid to gas ratio was found to increase nonlinearly with removal percentage. More pumping power was required and gas-side pressure drops were higher. At removal rates above 96%, dibasic acid also had to be added to maintain SO_2 removal.

For SDAs, the SO_2 removal range was 90-97%. For higher removal rates with SDA, the Ca/S molar ratio was found to increase nonlinearly with removal percentage, and larger absorbent and byproduct handling systems were required.

Different NO_x control technologies were used to achieve higher levels of NO_x removal. This differed from the SO_2 control analysis where greater removal levels could be achieved by varying the operating conditions or process parameters. Rich reagent injection (RRI) was used to obtain 25% removal. RRI reduces NO_x formation by injecting amine-based compounds into the fuel-rich region of the furnace. SNCR was used to obtain 30% removal. A combination of RRI plus SNCR resulted in 43% removal. SCR was used to obtain 80-90% removal.

A pulse-jet fabric filter was used to control particulate matter (PM) to levels of 0.03-0.005 gr/acf (0.09-0.015 lb/MBtu). For higher removal levels, the air-to-cloth ratio decreases, the number of compartments increases and the number of bags is increased. For highest removal level, the weight and thickness of bag is also increased.

The results of the study indicated that the levelized COE for bituminous coals increased by \$0.57/MWh when the SO_2 removal was increased from the base value of 95% to a high level of 99%. Increasing the NO_x removal level from the base value of 80% to a high level of 90% raised the levelized COE by \$0.20/MWh. Finally, the higher level of particulate control increased the levelized COE by \$0.13/MWh. Therefore, the total increase in levelized COE in going from the base emission control levels to the highest control levels was only \$0.90/MWh.

Even with increased costs for retrofitting emission reduction equipment, coal-based power plants are still expected to remain competitive.

A key conclusion from this case study is that once FGD and SCR systems have been retrofitted, the incremental COE impact to increase SO_2 removal from 95-99% or NO_x removal from 80-90% is quite small, less than \$1.00/MWh. Most of the additional cost is for O&M expense and consumables.

Water Issues

Water demand is increasing throughout most sectors of the U.S. economy (agricultural, residential and industrial). This increased demand for water coupled with recent droughts has seriously strained the supply of water. Aquifer levels are dropping, especially in the West. Because of the diminishing supply of water, many recent power plant projects have selected or have been required to install air-cooled condensers, which can cut the water consumption of a combined cycle power plant by about 90%. This trend is nationwide, even in humid regions such as the Southeast. The use of air-cooled condensers has significantly reduced plant efficiency.

Restrictions on water consumption in the future will likely result in a loss in efficiency for new power plants.

Disadvantages of air-cooled condensers include higher capital costs, loss in plant capacity and an increase in heat rate. Air-cooled condensers result in a higher backpressure on the steam turbine, since the temperature of the condensing steam must be above the dry bulb temperature. In a conventional water-cooled condenser, the condensing temperature is keyed to the wet bulb temperature, which is typically

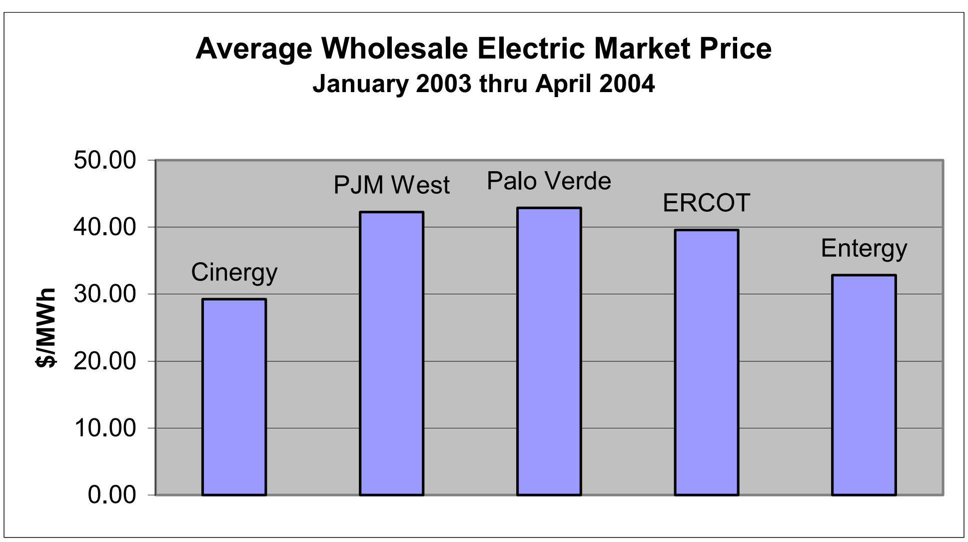
15-20°F below the dry bulb. The performance losses are greatest in the summer, when the need for capacity is greatest (for air conditioning). This loss in performance and capacity is a bigger issue for PC plants since all of the power is produced in the steam turbine, whereas only one-third of the power is produced from the steam turbine for IGCC or NGCC plants. To mitigate these performance losses, hybrid systems have been used on some projects, where a conventional wet condenser operates in parallel with an air-cooled condenser.

Market Price of Electricity from Coal-Based Plants

In a demand-driven competitive marketplace, where the wholesale market purchases electricity from the plant at the incremental cost of production, an investor cannot make a profit on a power plant until the market price of electricity is at or above the COE of that plant shown in the table in Figure 2.6. Usually, older, utility-owned power plants have paid off most or all of the debt and can be dispatched to the electric grid at a cost that is only slightly above the fuel and O&M costs of operating the plant. However, older coal-based power plants are also operationally less flexible and run optimally as base load plants. Given that the daily load is subject to peaks and valleys, the incremental market price is driven by the next most dispatched unit. In most regions, this is a gas-fired plant. In comparison to an older coal-based power plant, a new gas-fired plant has more flexible operating characteristics allowing it to respond more readily to "spikes" in load. However, a gas-fired plant has a higher fuel cost than a coal-based power plant. All things being equal, it is the relative mix of fuel types, heat rates and generation technologies that drive regional market prices, with coal and nuclear plants serving the base load, and natural gas prices driving the market on the margin.

Figure 2.11 provides representative average market clearing prices for various regions in the U.S. The graph shows that the average market price is significantly lower in regions where coal is the dominant source of electricity (i.e., Cinergy and Entergy) compared to regions where natural gas is the dominant fuel for electricity (PMJ, ERCOT and Palo Verde). This reinforces the benefit of lower electricity prices to the consumer where there is abundant, inexpensive coal.

Figure 2.11



Comparing the values in Figure 2.11 to the values in Figures 2.8 and 2.9 reveals the market risk of installing new capacity. Figure 2.8 shows that the levelized COE for a NGCC plant is approximately $50/MWh. Yet the average market prices shown in the four regions in Figure 2.11 are all well below that level. Therefore, an investor would not be able to recover the investment and cover the fuel and O&M costs in a NGCC plant in that region unless the price level reaches approximately $50/MWh by the time the unit is placed in service. If a coal-based plant were to be developed today, Figure 2.9 shows that the market price of electricity would need to be $62/MWh by the time the plant starts up for the investor to recover the fuel, O&M and capital costs in the first year. The comparison between the cost-recovery projections and the market prices is the key factor in developing a plant in a competitive marketplace.

A new plant will only be built if the investor expects to recover both the capital investment and operating costs.

Before investing in a new facility, the forecasted market prices must be sufficiently high enough to cover the cost of operating a plant while earning a return on the capital investment. In today's world, there are two fundamental views on the driving force behind the long-term forward price curve. One view is that a liquid, tradable energy futures market dictates pricing and the demand for investment in new power plants. Others argue that the future prices of electricity should be based on other fundamentals of supply, demand, fuel prices and infrastructure issues. This type of debate is a reason why there are many different projections of future electricity prices for any given region.

Regardless of the projections that are used to justify building or not building a power plant, once a plant is built, the profitability (or loss) of that plant is determined by the ability of a plant to operate successfully. The operation of a plant is dependent on the reliability of the plant and the capacity factor of the plant. The reliability is determined by the ability of a plant to operate when it is called upon to run (availability). The capacity factor is determined by the availability and the market conditions. In a competitive marketplace, the capacity factor will depend upon the market price of electricity compared to the production cost of operating the plant. In a regulated marketplace, profitability (or loss) of that plant will depend on the willingness of the regulator to include the capital portion (capacity charge) of a plant in the rate base, coupled with the dispatch rate of the plant which is determined by the production cost (fuel cost plus variable O&M cost) compared to other plants. When one considers that the capital placed at risk for a large coal-based power plant is in the order of $1 billion, it becomes obvious that the technology risks and market risks associated with competition from existing plants and other technology options must be given careful consideration.

Once a plant is built, it is dispatched based on its operating cost, regardless of the capital investment.

Conclusion

Over the past 20 years, significant improvements in performance and efficiency have been made to coal-based technologies. The use of supercritical boilers is becoming more commonplace around the world, and the re-introduction of this efficient technology has begun in the U.S. IGCC plants are expected to be competitive with conventional plants. While these improvements in coal-based technologies have occurred, new requirements for ever-stringent emission controls have continued to impact coal-based unit performance, efficiency and COE. Improvements in plant efficiencies continue to be the most cost-effective means to reduce CO_2 emissions from coal-based plants. The industry is meeting the challenge to increase the efficiency and decrease the cost for these emission control technologies, in order to minimize the levelized COE for coal-based generation.

There are many technical and economic factors that go into the decisions of whether or not to build a new coal-based power plant and which type of coal technology to use. All of these factors are used as inputs to economic models to project the levelized COE and the long-term viability of these investments. As the price of natural gas continues to rise, the economic benefits for coal-based generation will become even greater.