PULVERIZED COAL AND IGCC PLANT COST AND PERFORMANCE ESTIMATES

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Abstract

Cost estimates for subcritical, supercritical and ultrasupercritical pulverized coal (PC) plants are presented for representative US bituminous coals and compared with IGCC technologies. The basis of the designs are discussed, including the difference between the US and European definitions of efficiency and calculation methods. The build up of the various components of the Total Capital Requirement (TCR) are shown and the effects of different assumptions regarding the additional Owners costs (OC) on the Cost of Electricity (COE) for each technology are addressed. The results show that the Total Plant Cost (TPC) for IGCC is slightly higher than PC when designed for 90% equivalent availability and at the current state of development IGCC probably requires more staff than PC. There are also additional cost elements and higher perceived risk factors for IGCC that can affect the project development schedule and financing charges and increase the Owners Costs to a greater extent than for PC. If IGCC is to become a real option for coal-based Power Generation some additional incentives may be required.

Overview of Coal-Fired Generation Technologies

Coal-fired power plants are making a dramatic comeback as the rising cost of natural gas has prompted the cancellation of numerous gas-fired combined cycle projects and the curtailment of operations at many existing plants. This renewed interest in coal is primarily driven by economics and the need for fuel diversity, although significant concerns remain about the environmental impact of these new coal plants. Most observers expect that further reductions in permitted emissions from coal-fired power plants are likely to be enacted. The fact is that coal-fired power plant emissions can be reduced to very low levels with only moderate cost impacts. In addition, new technologies such as integrated gasification combined cycle (IGCC) are being developed to significantly improve the generating efficiency and reduce the environmental impact of coal-fired power plants.

The primary types of coal-based technologies being considered for new power plants are described in the following paragraphs, with a special emphasis on comparisons of their performance and efficiency. In addition, the impact of coal properties and emission control requirements on unit cost and performance are discussed. Cost estimates for subcritical, supercritical and ultrasupercritical pulverized coal (PC) plants are presented for representative US bituminous coals and compared with IGCC technologies.

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 16.5 Mpa/538°C (2,400 psig/ 1,000°F) superheated steam, with a single reheat to 538°C (1,000°F). Since the early 1980's, 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 24.8 Mpa (3,600 psig), with 565-593°C (1,050-1,100°F) main steam and reheat steam temperatures. On the average, these SC units have heat rates that are about 7 to 8 percent lower than subcritical units. Steam temperatures above 565°C (1,050°F) are often referred to as ultrasupercritical (USC) conditions.

In the last 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.

The choice of subcritical cycles for the coal 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 of higher efficiency cycles, such as SC. In the 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 1/3 of SC units are in the U.S. However, all of these

U.S. units were built prior to 1991. None have been built since, although a few have recently been announced. Whereas there has been considerable activity with new SC units in Europe and Japan in the past decade.

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, Japan and Korea 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 more reliable and less costly. 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. 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.

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 power produced is to increase the unit's efficiency, so that less coal is burned per MWh generated. Figure 1 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) 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 fire less coal to produce the same energy. It is estimated that if the next 10-GW of coal fired plants were to be built with using more efficient supercritical 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. In the event that CO_2 capture is required, an advanced USC plant would have 18-22% less flue gas to be treated and CO_2 to be captured compared to an equivalent-sized subcritical PC plant.

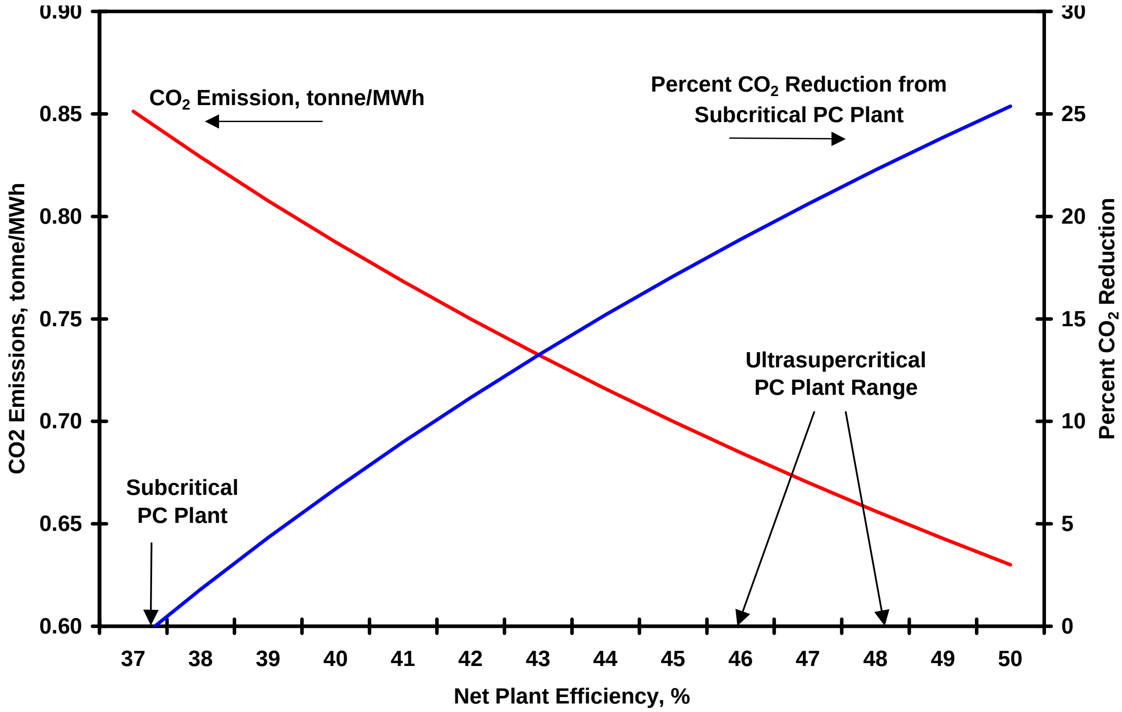

Figure 1. CO_2 Emissions vs. Net Plant Efficiency

Integrated Gasification Combined Cycle (IGCC)

IGCC allows the use of coal in a power plant that has 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. 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.

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, this case study 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. High-pressure oxygen-blown gasification also provides advantages if CO_2 capture is considered at a later date.

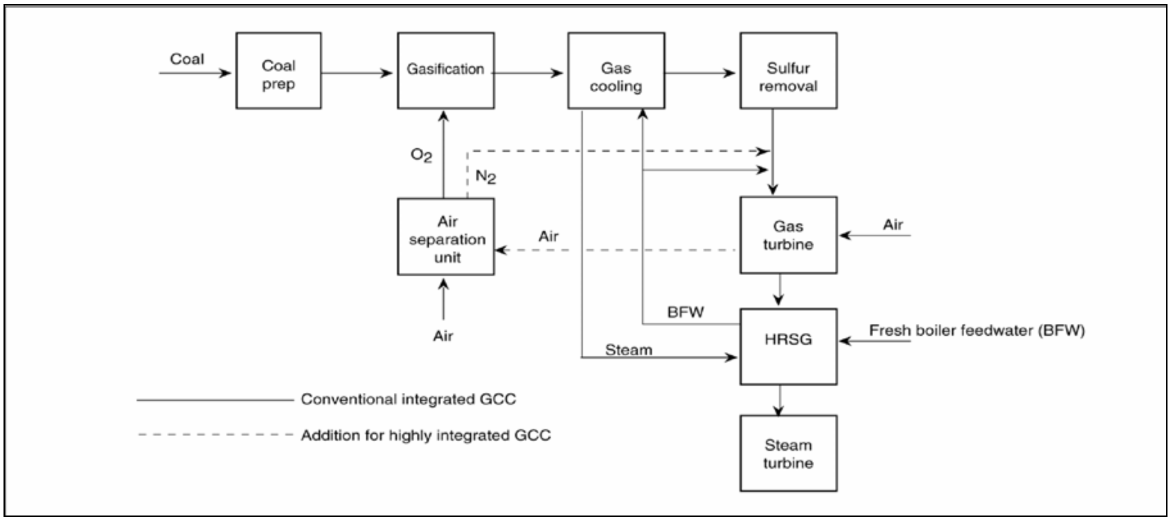

Figure 2. IGCC Block Flow Diagram

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 ChevronTexaco (recently acquired by GE) and ConocoPhillips, 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 the large commercial gas turbines now entering the marketplace. However, recent experience has shown that a spare gasifier can significantly improve IGCC availability.

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 can result in higher 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 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 15-20 ppmv range, just above those from NGCC units, and when converted to the base of 3% O_2, are similar to those from PC boilers.

An advantage of adding the extra mass from the 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 commercial 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 DOE's Clean Coal Technology demonstration program, but are now operating commercially without DOE support.

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 Co. Polk Power Station IGCC project in Florida started up in September 1996 and is based on 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 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 solids byproducts as coal combustion processes, and will use almost 40% less total water.

Comparison of US and European Plant Performance (Heat Rate) Estimates

There are many differences between the U.S and European practice for evaluating and estimating the efficiency of coal fired power plants. The most obvious difference is that the U.S conventionally reports heat rates and efficiencies based on the Higher Heating Value (HHV) whereas the European convention is to use Lower Heating Value (LHV). LHV assumes that the water formed during combustion remains in the vapor phase, i.e. the latent heat of vaporization is not recovered. Efficiency based on LHV gives a truer representation of the percentage of recoverable energy that is converted to electric power. However, US utilities purchase fuel on a $/MBtu (HHV) basis. Since they pay for fuel on an HHV basis they also want to know the plant efficency on an HHV basis. For most bituminous coals the LHV/HHV ratio is about 0.96, so a

40% HHV efficiency would be about 41.7% on an LHV basis. The LHV/HHV ratio decreases with decreasing coal rank, primarily due to increasing moisture content. For example, the LHV/HHV ratio for Wyoming subbituminous coal is about 0.925, while the ratio for Texas lignite drops to around 0.90.

There continues to be some debate on the methodology for calculating LHV. According to the B&W Handbook, LHV is purely a function of the fuel bound hydrogen content and does not include hydrogen that is bound with the moisture in the fuel. However, Europeans prefer the International Energy Agency (IEA) formula that does account for the moisture in the coal. This equation for LHV is as follows:

$$LHV = HHV - (91.1436 * H + 10.3181 * H_2O + 0.3439 * O)$$

where H, H_2O, and O are on an as-received basis. The LHV/HHV ratios referenced in this paper are based on the IEA formula which properly accounts for moisture in the coal.

The colder climate in much of Europe and their traditionally higher fuel costs lead to differences in design conditions and philosophy. In general the European plants use lower sulfur higher ash fusion temperature international merchant coals as compared to the U.S wider usage of higher sulfur coals such as Illinois #6 and Pittsburgh #8. The better quality international merchant coals lead to lower auxiliary power requirements for the flue gas desulfurization process. Also the higher Btu content and lower ash levels lead to lower auxiliary power for coal and ash handling.

Cooling water temperature and the achievable condenser vacuum has an important effect on heat rate. The generally colder climate in Europe results in lower cooling water temperatures, and therefore lower condenser pressures. Evaluations based on European plants, particularly Danish units, often use a condenser pressure as low as 2.5 kPa-abs (0.74” Hg), whereas condenser pressure is more typically 5 kPa-abs (1.5” Hg) in Japan and 6.75-8.5 kPa-abs (2-2.5” Hg) in the United States. However, if the condenser pressure were reduced from 6.75 kPa-abs to 5 kPa-abs, unit heat rate would improve by about 1.3%. If it could be reduced to the Danish level of 2.5 kPa-abs, heat rate would improve by 3.3% relative to a unit operating with a condenser pressure of 6.75 kPa-abs.

The availability of once-through cooling water at many European power plant locations also has a beneficial effect on heat rate by eliminating the auxiliary power requirements for pumping cooling water to the towers. This can typically reduce overall heat rate by about 0.6%.

The European standards for calculation of boiler efficiency and turbine efficiency differ from U.S. standards. The U.S. boiler efficiencies are based on ASME test codes, whereas the European boiler efficiencies are based on DIN standards. DIN is the German standards organization. The test codes differ in their methods of calculating heat losses and design margins.

The combined effects of once-through cooling water at low temperature, higher boiler efficiency due to use of only high-quality coals, and the different efficiency calculation methods account for the differences in attainable heat rates reported by U.S. and European researchers for PC plants with the same steam conditions and reheat stages. Thus, European analysts may report heat rates 8-10% lower (and net plant efficiencies about 4 percentage points higher) for essentially comparable supercritical plants.

Effects of Coal Quality on Coal-Based Power Generation Technologies

PC Plants. Coal properties affect PC plant heat rates and boiler size. There is a significant cost impact for designing a PC boiler to burn a subbituminous coal or lignite compared to lower-moisture, lower-ash, and lower-alkali bituminous coal. 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 prevent slagging of the convective pass. Subbituminous fuels and lignites generally have alkaline ashes with low ash softening temperatures, which require large PC furnaces. High moisture and high ash contents also 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. 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. A 10°C (18°F) increase in air heater exit temperature reduces heat rate by about 15 kJ/kWh, or approximately 0.2%. Danish supercritical plants, for example, are usually designed for high-quality international merchant coals with low sulfur content.

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 due to the Clean Air Act. Many of these low sulfur coals also have high ash fusion 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 which chemically change 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 converted from high-sulfur eastern bituminous coals to low-sulfur subbituminous coals, primarily from the Powder River Basin (PRB) region. Due to changes in moisture and volatile content, 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. In many cases the plants have been slightly derated due to use of the lower rank coals

IGCC Plants. IGCC plants work very well with bituminous coals. Both the Wabash River and Polk Power Station IGCC plants were designed around bituminous coals. Previous studies for E-Gas IGCC plants show a drop off 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 coals increases, the achievable slurry concentration becomes lower. Combined with the increased ash content in 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.

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 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).

Most IGCC studies have been based on using bituminous coals. The entrained flow gasifiers of ChevronTexaco, Shell and ConocoPhillips all perform better with lower ash, lower moisture bituminous coals. Given the abundance and low cost of U.S. resources of low rank fuels such as Powder 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. Previous studies by EPRI and others indicate that E-Gas IGCC plants do not appear to compete economically with PC plants when using PRB coals and lignites.

Although entrained-flow gasifiers can process all ranks of coal, the existing commercial gasifiers all show a marked increase in cost and reduction in performance with low-rank and high-ash coals. For slurry-fed gasifiers (ChevronTexaco and ConocoPhillips), the energy density of high moisture and/or high ash coal slurries is markedly reduced, which increases the oxygen consumption and reduces the gasification efficiency. For dry-coal-fed gasifiers (Shell) 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

Although IGCC is close to being competitive with PC for bituminous coals, the IGCC–PC capital cost and COE gap widens for low rank coals to about $200-300/kW for PRB coal and approximately $400/kW for U.S. lignites. Figure 3 shows the impact of coal rank, or coal heating value, on the relative heat rates and capital cost of PC plants and IGCC plants. This illustrates the widening gap for lower rank coals, particularly for slurry-fed gasifiers such as ChevronTexaco or ConocoPhillips. This reinforces the need for development of improved gasifiers, such as the KBR Transport gasifier, for low rank coals.

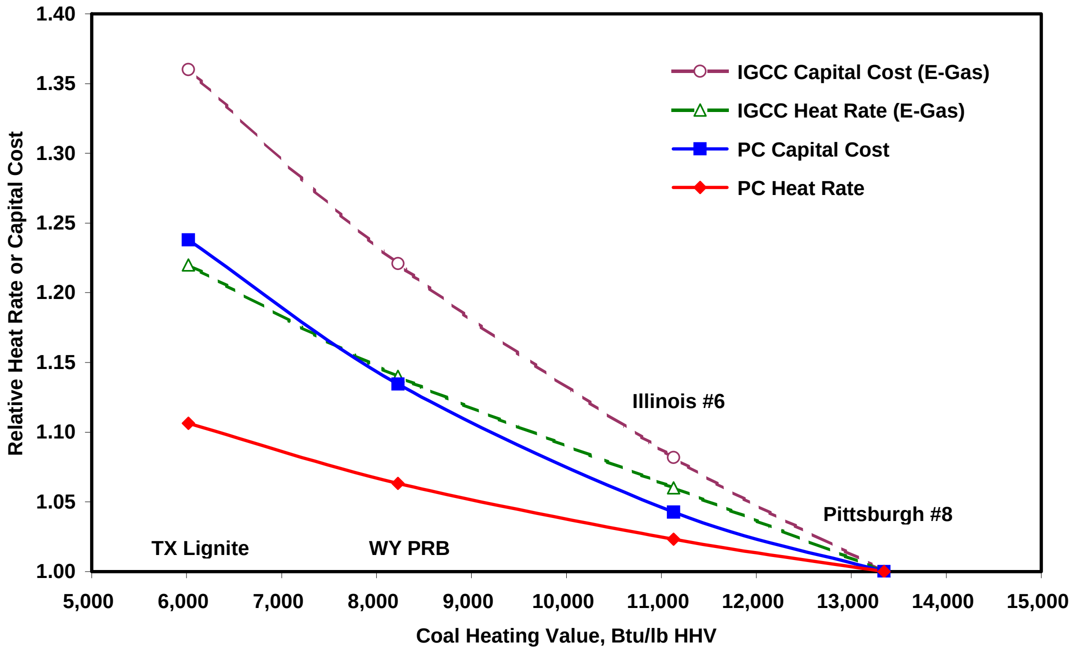

Figure 3. Effect of Coal Quality on Heat Rate and Capital Cost

Design and Economic Basis

The design and economic criteria that served as a common basis for the estimates presented in this paper are as follows.

Design Criteria

The site location chosen by EPRI is Kenosha, Wisconsin, a site typical of power generation facilities located in Middle America and having access to water and rail transportation. The site is assumed to be clear and level with no special problems.

The general design criteria are as follows:

- Systems are based on a 15.5°C (60°F) design ambient temperature.
- Atmospheric pressure is assumed to be 0.99 bar(14.4 psia)
- Cooling water is provided by mechanical draft cooling towers
- Condenser pressures are 2.0 in HgA
- Units are considered base loaded.

- Equipment is designed for a 30-year plant life.
- Plants are considered grassroots facilities.
- Two bituminous coals are considered: Pittsburgh #8 and Illinois#6. The characteristics and analyses of these coals are presented in Table 1.
- Coal is delivered to the site by rail.
- Final disposal of ash is off site.
- Raw water is from Lake Michigan.

The PC plants are designed with wet limestone FGD for 95 percent sulfur removal and with low NOx burners and Selective Catalytic Reduction (SCR) units to reduce NOx emissions to <0.1 lb./MBtu fired. For the bituminous coals no extra mercury control steps are included since mercury is largely captured in the FGD.

The IGCC plants have been designed for well over 99% sulfur removal and with SCR in the HRSG section so that the SO_2 and NOx emissions from the gas turbine exhaust are both less than 2ppmv at 15% oxygen (equivalent to 0.006 lb/Mbtu) in the gas turbine flue gas. A bed of pre-sulfided activated carbon is used to remove >90% of the Mercury from the syngas prior to sulfur removal and clean syngas being fed to the gas turbine.

Plant battery limits includes:

- All process and support facilities
- Fuel handling and storage
- Water intake structure and waste water treatment
- Offices, maintenance shops, and warehouses
- Step-up transformer

The switchyard and transmission lines are excluded from the design and cost estimate scope.

Economic Criteria

The costs reported in this paper are expressed in 2003 dollars. Total Plant Cost (TPC) is comprised of the following components:

- Direct Field material and Labor Costs
- Subcontract Supply and Erect Costs & Lump Sum Turnkey Costs
- Indirect Field Costs (Construction Management & Heavy Haul/Heavy Lift)
- Home Office Costs (Engineering, Design and Procurement)
- Contractor's Risk and Profit

- Contingency

Table 1 Coal Characteristics

	Pittsburgh #8	Illinois #6
Proximate Analysis (Wt %) (As received)		
Moisture	5.2	13.0
Ash	7.1	11.0
Fixed Carbon	51.0	41.0
Volatile Matter	36.7	35.0
Ultimate Analysis		
Moisture	5.2	12.2
Carbon	73.8	61.0
Hydrogen	4.9	4.25
Nitrogen	1.4	1.25
Chlorine	0.07	0.07
Sulfur	2.13	3.28
Oxygen	5.4	6.95
Ash	7.1	11.0
Ash Mineral Analysis		
SiO_2	46.45	50.66
Al_2O_3	24.04	19.00
TiO_2	1.19	0.83
Fe_2O_3	18.63	20.30
CaO	4.10	2.42
MgO	0.58	0.89
Na_2O	0.97	0.67
K_2O	1.36	2.54
P_2O_5	0.21	0.17
SO_3	2.08	1.90
Undetermined	0.30	0.58
Ash Fusion Temperature		
Reducing °C (°F)		
Initial Deformation		
Softening (H=W)	1216(2220)	1143(2090)
Heating Value (As received)		
Higher MJ/kg (Btu/lb)	30.84(13,260)	25.54(10,982)
Lower MJ/kg (Btu/lb)	29.76(12,797)	24.61(10,584)

Construction labor costs are based on the use of union labor at the Kenosha, Wisconsin site, and include:

- Fringes (vacation days, holidays, paid leave, health insurance, other employer benefits)
- Legalities (FICA, state and federal unemployment insurance, and workmen's compensation)

Plant Book Life. In the increasingly deregulated power market place it is generally no longer appropriate to use the traditional public utility practice of 30 years for the calculation of cost of electricity (COE). In this study a 20 year book life is assumed for plant costs (although designed for 30 years of operation).

Levelization Factor. A 20-year constant dollar levelization factor (carrying charge) is used that is a multiplier applied to the Total Plant Cost (TPC) to give a capital charge in $/MWh. The factor takes into account owners costs (OC), Allowance for Funds used during Construction (AFUDC), depreciation and return on investment. The methodology used to calculate the carrying charge factor is based on the EPRI Technical Assessment Guide (TAG). The TAG financial parameters are shown in Table 2. For coal plants the levelization factor is typically 0.142 and for natural gas plants 0.135. The slightly lower factor for natural gas plants reflects the shorter construction period of 2 years versus 3 years for the coal-based plants. The factor to be used for any individual study will depend on the specifics of the financing scheme, return on investment requirement, payback period etc.

The typical coal plant carrying charge factor of 0.142 is based on an assumed construction time of 3 years which leads to adding about 11% in AFUDC to the TPC. Fairly modest start-up costs result in adding another 4-5% to the TPC. 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, whereas nearly 19% is added to the TPC for IGCC plants. This results in a levelization factor of 1.46 for the IGCC plants, compared to the typical factor of 1.42 for PC plants.

However recent experience has shown increased efforts are required nowadays in the permitting, project definition and project development phases that must also be accounted for. Some companies may expense these costs whereas others will seek to recover them from project revenues. Besides these additional front end charges, higher finance charges will often be charged by banks, particularly for newer technologies, such as IGCC, that do not have the power industry operating history and historical precedent of the PC plants. Recent studies in which EPRI has participated have shown a range of an additional 20% to 40% of TPC when different organizations have evaluated the total capital requirement. This can make a huge difference in the evaluated Cost-of-Electricity (COE).

Table 2 TAG Financial Parameters

		Current Dollars		Constant Dollars	
	% of Total	Cost,%	Return,%	Cost,%	Return,%
Debt	45	9.0	4.05	5.83	2.62
Preferred Stock	10	8.5	0.85	5.34	0.53
Common Stock	45	12.0	5.40	8.74	3.93
Total Annual return	100		10.30		7.09
Inflation Rate, %	3.0				
Federal Tax, %	34.0				
State Tax, %	4.15				
Fed & State Tax, %	38.0				
Discount Rates					
After Tax			8.76		5.59
Before Tax			10.30		7.09

Coal and Natural Gas Prices

For the Kenosha, WI site a delivered cost of $0.948/GJ HHV ($1.00/MBtu) is used for the Illinois#6 and $1.422/GJ ($1.50/MBtu) for Pittsburgh #8. US natural gas prices have been consistently over $4.73/GJ ($5.00/MBtu) for the past year.

Limestone and Solid Waste Disposal Costs

A deliverd cost of $13.23/tonne ($12/ton) for limestone and a solid waste disposal cost of $17.64/tonne ($16/dry ton) has been used.

Capacity Factor

A capacity factor (CF) of 80% is used as the basis for the economic comparisons. However it is recognized that with the generally higher fuel cost for natural gas that such plants may not be dispatched to such a high capacity factor. The sensitivity of levelized cost of electricity to capacity factor is discussed later in this paper.

Economics of Power Generation Technologies

Table 3 summarizes the results of an EPRI study which evaluated the performance, capital cost and levelized cost of electricity (COE) for 500 MW PC and IGCC plants based on the use of Pittsburgh #8 and Illinois #6 bituminous coals. For comparison, the table also includes cost and performance for a nominal 500 MW natural gas-fired combined cycle plant.

The capital cost estimates shown in Table 3 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 TCR.

The major components of the 500-MW PC units include coal-handling equipment, the boiler island, turbine-generator island, FGD system, fabric filter, bottom 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 Table 3, the steam conditions are 16.5 Mpa/538°C (2,400 psig/1,000°F) superheated steam, with a single reheat to 538°C (1,000°F). For the SC unit, the main steam pressure is 24.8 Mpa (3,600 psig), with 593°C (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; and 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 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.

The IGCC plants shown in Table 3 are two train plants based on the E-Gas gasification process and GE 7FA+e gas turbines for a nominal net output of 500-550 MW. The E-Gas process was selected as being representative of commercially available oxygen-blown entrained flow processes. An IGCC plant based on the E-Gas process will have a heat rate that is not quite as low as a Shell-based IGCC, but its capital cost will be lower. Also, the E-Gas-based IGCC heat rate will be significantly better than for a Texaco quench-based IGCC, however its capital cost will be higher.

Table 3. Cost, Performance and Economics for Nominal 500 MW Power Plants

	PC Subcritical	**PC Super-critical**	**IGCC (E-Gas) W/ Spare**	**IGCC (E-Gas) No Spare**	**PC Subcritical**	**PC Super-critical**	**IGCC (E-Gas) W/ Spare**	**IGCC (E-Gas) No Spare**	**NGCC High CF**	**NGCC Low CF**
Fuel	PT #8 Coal	PT #8 Coal	PT #8 Coal	PT #8 Coal	IL #6 Coal	IL #6 Coal	IL #6 Coal	IL #6 Coal	Nat. Gas	Nat. Gas
Total Plant Cost, $/kW	1,230	1,290	1,350	1,250	1,290	1,340	1,440	1,330	440	440
Total Capital Requirement, $/kW	1,430	1,490	1,610	1,490	1,500	1,550	1,710	1,580	475	475
Fixed O&M, $/kW-yr	40.5	41.1	56.1	52.0	42.5	42.7	61.9	57.2	5.1	5.1
Variable O&M, $/MWh	1.7	1.6	0.9	0.9	2.9	2.7	1.0	1.0	2.1	2.1
Avg. Heat Rate, Btu/kWh (HHV)	9,310	8,690	8,630	8,630	9,560	8,920	9,140	9,140	7,200	7,200
Capacity Factor, %	80	80	80	80	80	80	80	80	80	40
Levelized Fuel Cost, $/MBtu (2003$)	1.50	1.50	1.50	1.50	1.00	1.00	1.00	1.00	5.00	5.00
Capital, $/MWh (Levelized)	25.0	26.1	28.1	26.0	26.1	27.2	29.9	27.7	8.4	16.9
O&M, $/MWh (Levelized)	7.5	7.5	9.2	8.6	9.0	8.8	9.8	9.1	2.9	3.6
Fuel, $/MWh (Levelized)	14.0	13.0	12.9	12.9	9.6	8.9	9.1	9.1	36.0	36.0
Levelized Total COE, $/MWh	46.5	46.6	50.2	47.5	44.7	44.9	48.8	45.9	47.3	56.5

The basic configuration includes two trains of air separation units, two operating gasification trains, a single acid gas removal train, two combustion turbines and HRSG's and a single reheat steam turbine.

The gasification plant is sized to fully load the combustion turbines at 15°C (59°F). Natural gas is used for startup and as a backup fuel. The combustion turbines are designed for dual-fuel capability and natural gas can be used in the event of gasification plant outages.

Oxygen of 95% purity by volume is supplied from the cryogenic air separation units. About 25-35% of the air for the ASU is supplied from the gas turbine air compressor with the balance of the supply coming from the ASU's own separate air compressor.

Combustion turbine NO_x emissions are controlled by fuel gas moisturization and dilution with nitrogen (supplied from the ASU) at the combustors.

The E-Gas gasifier is refractory lined and needs planned outages of 25-30 days for refractory replacement every 2-3 years. If the owner must have an overall IGCC equivalent availability of 90%, a spare gasifier would be required. A spare gasifier reduces the scheduled outage time and some of the forced outage time. Table 1 shows IGCC cases with and without a spare gasifier.

Plant capacity factor has a significant impact on the COE, especially for capital intensive coal-fired technologies. Figure 4 shows the impact of capacity factor on the constant dollar levelized COE for the bituminous coal-based technologies. The NGCC case from Table 1 is included for comparison. A spare gasifier for the IGCC case would not be necessary unless the plant was required to operate at very high capacity factors. 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 curves show that PC plants have a slight COE advantage over an IGCC plant without a spare gasifier throughout the range of capacity factors. This PC plant COE advantage becomes larger if the IGCC plant incorporates a spare gasifier. The coal-based technologies become preferred over NGCC at capacity factors over 78-80%.

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. About 75% of the total levelized COE for a NGCC unit is due to fuel cost, whereas this drops to only about 30% for the coal-based technologies. This means that even though NGCC and coal may have the same total levelized COE, it is unlikely that the NGCC plant would ever dispatch before the coal plant due to its higher fuel cost. Therefore it is unlikely that a NGCC plant would operate at anywhere close to 80% capacity factor. A recent EPRI report indicates that in 2003 the average capacity factor for natural gas-fired combined cycle 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.

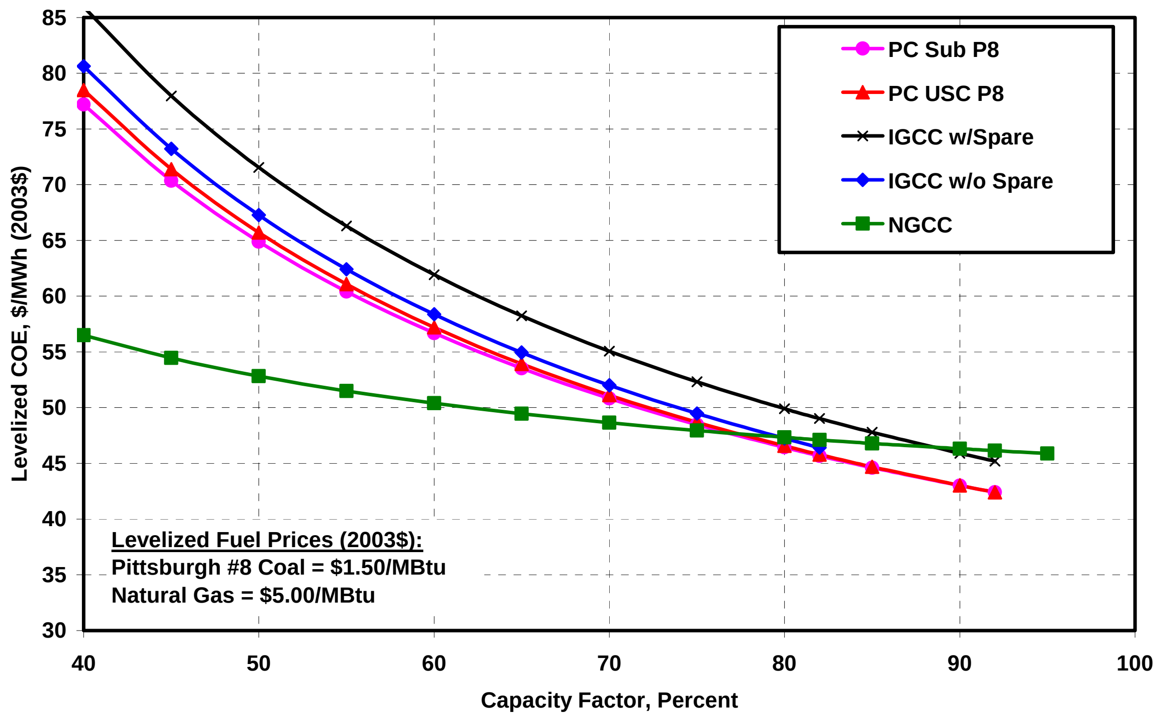

Figure 4. Impact of Capacity Factor on Levelized COE

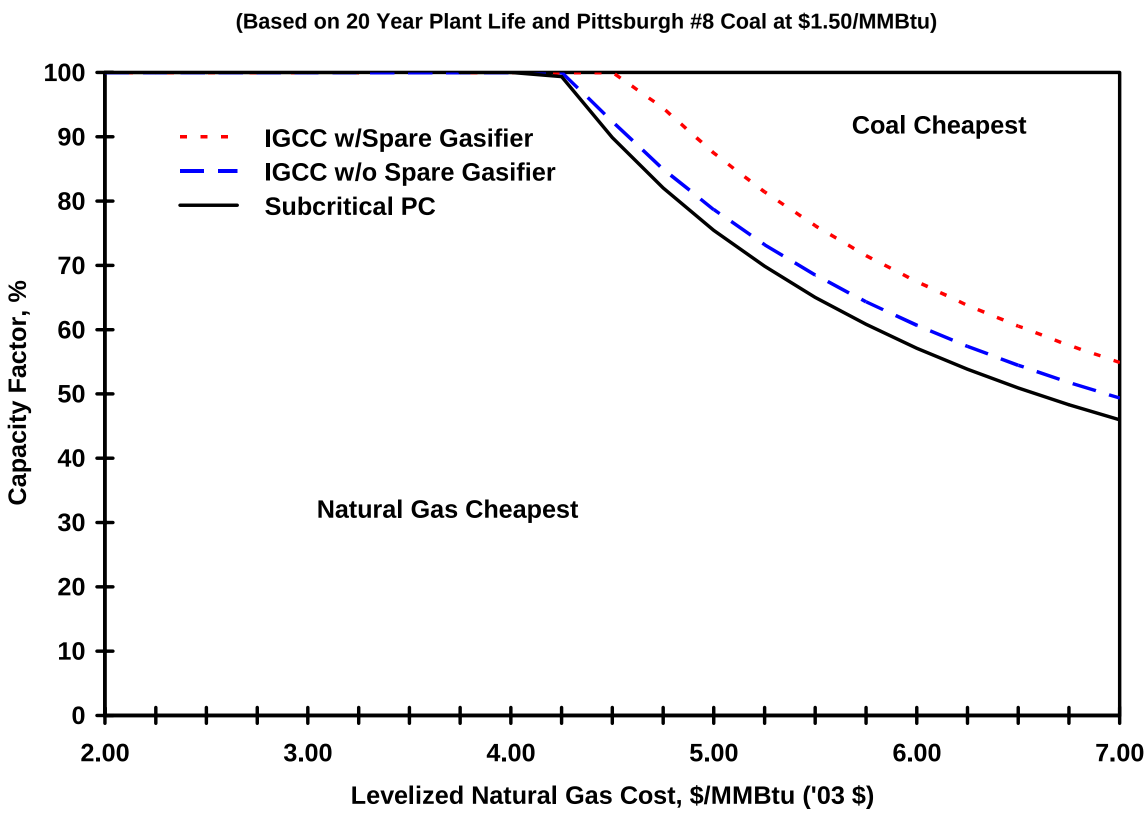

Figure 5. Breakeven Capacity Factor and Fuel Cost for Natural Gas vs Coal

Together, capacity factor and fuel cost can be analyzed to determine which fuel and technology will provide the lowest COE. Figure 5 presents a chart that compares PC and IGCC technologies (using Pittsburgh #8 coal at $1.50/MBtu) with NCGC for a range of capacity factors and fuel costs. For high capacity factor (>80%) baseload plants, coal is cheaper than gas when gas prices rise above $4.75/MBtu.

Conclusions

Over the past 20 years, significant improvements in performance and efficiency have been made to coal-based technologies. The use of SC boilers is becoming more commonplace around the world, and the re-introduction of this efficient technology has begun in the U.S. 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. The industry is developing new technologies such as integrated gasification combined cycle (IGCC) in order to meet the challenge to increase efficiency and decrease emissions, while minimizing the levelized COE for coal-based generation.

The cost and performance estimates presented in this paper show that for both Pittsburgh #8 and Illinois #6 coals, there is very little difference between subcritical and supercritical PC plants on a levelized cost of electricity (COE) basis. The improved efficiency of the supercritical unit is off-set by higher capital costs, resulting in essentially the same COE. However, in the event that CO_2 capture is required, a more efficient supercritical PC plant would have less flue gas to be treated and less CO_2 to be captured compared to an equivalent-sized subcritical PC plant.

IGCC plants are nearly competitive with PC plants if a spare gasifier is not required. The gap between IGCC and PC is slightly larger for Illinois #6 coal than for Pittsburgh #8 coal. If a spare gasifier is required in order to operate at IGCC equivalent availabilities approaching 90%, the IGCC COE will be increased by $2.7 to 2.9/MWh, for Pittsburgh #8 and Illinois #6 coals, respectively.

There are also additional cost elements and higher perceived risk factors for IGCC that can affect the project development schedule and financing charges and increase the Owners Costs to a greater extent than for PC. If IGCC is to become a real option for coal-based Power Generation some additional incentives may be required.

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 and volatility of natural gas continues to increase, the economic benefits for coal-based generation will become even greater.

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