Integrated Gasification Combined Cycle Technology

An American Electric Power Service Corporation White Paper

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Table of Contents

I. Introduction

More than half of the electricity generated in the United States is fueled by coal. And roughly 90 percent of all coal mined in the U.S. goes toward generating electricity. Meanwhile, political instability around the world adds urgency to the goal of a nation and an economy that is domestically powered. The U.S. already produces 25 percent of carbon dioxide in the world, and 82 percent of the greenhouse gases produced in this country come from fossil fuels, including coal. AEP is the largest consumer of coal in the United States. We are in an environmental conundrum – living with coal is a challenge, yet we can't live without it.

Technological innovations are critical to the future of the coal-fired electric industry in the United States. Clean coal technologies must be embraced by the electric utility industry across the country, and at this point in history, Integrated Gasification Combined Cycle (IGCC) technology is the premier clean coal technology. This is a public responsibility AEP takes very seriously. Earlier this week, the Company was honored by the EPA with a 2005 Climate Protection Award for demonstrating ingenuity, leadership and public purpose in its efforts to reduce greenhouse gases.

AEP, as the nation's largest consumer of coal, is committed to leading the industry in the technology destined to become the standard. The Company already has taken a great many strides toward clean coal – through retrofits of emission control technologies on our power plants, and through carbon sequestration efforts across the globe.

According to the EPA's 2003 statistics, Ohio led the nation in NOx and SO_2 emissions, and ranked only behind Texas in CO_2. It is AEP's opinion that taking this first step into the new era of electric generation using IGCC technology is both fiscally responsible and the right thing to do as a matter of public policy, both for AEP and for Ohio.

No single technology will allow the U.S. electric utility industry to continue producing low cost, reliable electricity. A diverse array of technologies and strategies will ensure the security and sustainability of the U.S. electric grid. But key to any successful strategy will be the expansion of commercial IGCC technology.

With this background in mind, Columbus Southern Power Company and Ohio Power Company, subsidiaries of AEP, filed an application March 18, 2005, with the Public Utilities Commission of Ohio seeking authority to recover costs related to building and operating a new clean-coal technology power plant.

AEP has announced its intent to build up to 1,200 megawatts of new generation using IGCC clean-coal technology, the largest commercial-scale use of the technology for power generation in the United States, and the largest IGCC power project announced to date. AEP has identified properties in Kentucky, Ohio and West Virginia as sites under consideration. IGCC technology represents an advanced form of coal-based generation that offers enhanced environmental performance.

This white paper is being submitted to the Public Utilities Commission of Ohio to discuss the issues surrounding AEP's intention to construct a commercial 600-MW IGCC plant in Meigs County, Ohio. This paper includes three main topics:

- A description of IGCC and other generating technologies,
- Carbon capture and sequestration considerations, and
- The economics of IGCC.

II. Generating Technology Options

In considering options for new investments to meet growing electricity demand and to replace retiring generation capacity, several technologies merit consideration.

Fossil fuels will continue to play a role in our nation and – owing to the company's location near an abundant source of low-cost coal – at AEP. Advanced technologies using coal and natural gas for power generation in an efficient, sustainable manner comprise a key portion of AEP's portfolio of technology options.

Coal-based technologies being considered include pulverized coal (PC) combustion designs; circulating fluidized bed (CFB) combustion designs; and integrated gasification combined cycle (IGCC) designs. PC and CFB systems are options already in widespread use for reliable and affordable baseload electricity production.

IGCC has been proclaimed by some as *the* clean-coal technology. Precluded by natural gas combined cycle (NGCC) operations during the low-price heyday of natural gas, coal-fired IGCC has only recently become the favored option, although the technology has existed for decades.

In addition, NGCC plants, which require the least up-front capital but are vulnerable to gas-price volatility, also must be considered. The evaluation of each of these fossil fuel technologies takes place in the context of current suitability for reduction of carbon and other emissions, as well as their respective potentials for future retrofits to remove carbon emissions.

Non-fossil fuel options include nuclear and renewable energy. New reactor designs and ongoing improvements in safety systems make nuclear power an increasingly viable option as an emission-free power source, but concerns about public acceptance, waste storage and capital costs continue to temper AEP's interest in new nuclear power. Renewable energy, especially wind and biomass, represents another approach to emission-free power generation, and AEP continues to aggressively pursue cost-effective opportunities in this area.

Finally, distributed resources and energy storage technologies hold potential in complementing new generation options by optimizing the operation of existing electric power infrastructures.

It must be recognized that there are many variables that impact the capital cost of a power plant. Some of those factors are:

- The cost to transport material to the site,
- The impact of ambient temperatures on the design and performance of a power plant,
- The marketplace itself, which can impact the prices of critical commodities including steel and concrete,
- The final design of the plant, which will impact the type of equipment and the cost of the equipment selected,
- The performance requirements such as emission limits and design efficiency, and
- The structure of the contracts, which will impact the risk premium (contingency) included in the cost of the facility.

Integrated Gasification Combined Cycle

The first patent for a gasifier was granted in Germany in 1887. Widespread as a chemical plant technology from that point through the 1950s, IGCC took off as a commercially feasible technology for electricity generation following key studies begun by the U.S. Department of Energy in 1970. In 1980, Texaco Gasification (now owned by General Electric) was contracted to build the Cool Water pilot plant in southern California. That plant was commissioned in 1984.

The basic IGCC concept was first successfully demonstrated at commercial scale at the Cool Water Project from 1984 to 1989. There are currently two commercial-size, coal-based IGCC plants in the United States and two in Europe. The two U.S. projects were supported initially under the DOE's Clean Coal Technology demonstration program, but are now operating without DOE support. The 262-MW Wabash River IGCC re-powering 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 Texaco gasification technology.

The first of the large 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 335-MW 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 IGCC process employs a gasifier in which coal is partially combusted with oxygen and steam to form what is commonly called "syngas" – primarily a combination of carbon dioxide, carbon monoxide, water vapor and hydrogen. The sulfur in the fuel forms hydrogen sulfide in the gasifier, and the ash is converted to a glassy slag. The syngas is then cleaned to remove the particulate and sulfur compounds. Mercury can also be removed in a bed of activated carbon. The syngas then is fired in a gas turbine to generate electricity. The hot exhaust from the gas turbine passes to a heat recovery steam generator (HRSG), where it produces steam that drives the steam turbine generator. Power is produced from both the gas and steam turbines. Appendix A provides an illustrated schematic of the process.

Among the three major types of gasifier systems used today, entrained-flow gasifiers have been selected for the majority of IGCC project applications. Gasifiers of this design operate at temperatures above the slagging temperature of the fuel, and as a result, the formation of tars and methane is avoided. Entrained flow designs include the coal/water-slurry-fed processes of 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 that are of sufficient size to fuel large commercial gas turbines. AEP believes this technology is capable of achieving the environmental benefits of a natural gas-fired plant, while capitalizing on the relatively low and stable fuel costs associated with coal.

Because gasification operates in a low-oxygen environment (unlike pulverized coal-firing, which is oxygen-rich for combustion), the sulfur in the fuel converts to hydrogen sulfide (H_2S), instead of sulfur dioxide (SO_2). The H_2S can be more easily captured and removed before the fuel is combusted. By reducing the volume of gas to be treated, it is possible to economically remove sulfur at high rates. The amount of waste product is also minimized compared to the sorbent technologies used by PC plants.

Removal rates of 99 percent and higher are common using technologies proven in the petrochemical industry. That removal rate is transferable to the electric generation industry. IGCC units also can be configured to operate with very low NOx emissions without the need for Selective Catalytic Reduction (SCR). NOx emissions typically fall in the 15-20 ppmv ranges, just above those from NGCC units, and are similar to those from pulverized coal-fired boilers equipped with low NOx burners and SCR systems.

Integrated gasification combined cycle is of particular interest to AEP, in light of the abundance, accessibility, and affordability of high-rank bituminous coals that are abundant in the Midwest. An IGCC plant also is capable of operating on other coal types, such as sub-bituminous coals and lignite coals, as well as other feedstocks such as petroleum coke; although some of the IGCC technologies are better suited for bituminous coals. IGCC also is well positioned for integration of carbon capture and sequestration technologies, which could become a critical approach in mitigating greenhouse gas emissions.

The AEP IGCC plant will be designed to burn Eastern bituminous coal, similar to that of the Pittsburgh-8 seam. It also will have the ability to blend petroleum coke with the coal in order to provide the flexibility to take advantage of lower-cost fuel should the opportunity arise. The fuel specifications were established to allow the use of much of Ohio's indigenous coal, providing a significant market potential for Ohio coal. However it is important to note that the Ohio River location of the plant – providing barge access – will allow AEP to obtain the lowest-cost coal available that meets our specifications, whether or not the coal is produced in Ohio. This will result in lower electricity costs to our consumers.

AEP entered into an agreement with General Electric and Bechtel in the early part of 2005 to conduct a scoping study for an AEP-specific IGCC plant. This work by GE and Bechtel has been conducted in parallel with their efforts to develop the scope and cost of a standard GE/Bechtel plant. The design proposed by the GE/Bechtel team uses GE's proprietary ChevronTexaco gasifier design.

AEP's scoping study provides for a number of technical deliverables. These deliverables will provide the basis for selecting the configuration of the proposed IGCC plant. To facilitate the development of this basic scope definition, a number of studies have considered the internal processes of the plant. This allows AEP to determine those options that offer the best fit to AEP's needs in terms of balancing capital costs and the benefits derived from certain options. Additionally, the scoping study provides for the development of high-level project schedules and an indicative cost estimate.

AEP will develop the scope for certain parts of the plant. The portions of scope being developed by AEP include those site-specific items with which AEP is most familiar. These include fuel and material unloading and handling, switchyard and transmission interconnection, river frontage improvements and development. The GE/Bechtel IGCC offering is based on the use of two GE 7FB combustion turbines. Each of these will exhaust into a heat recovery steam generator (HRSG). The steam produced by these HRSGs and from elsewhere in the process will be used to drive a steam turbine. The two gas turbines and the steam turbine will produce a net electrical output of 600 MW.

One issue with IGCC technology is whether it will have the same or better availability compared to conventional PC plants. Most industry data on the gasifiers currently in operation point to two significant design features that adversely impact availability: the fuel nozzle and the refractory. The environment under which the fuel nozzle must operate is a zone where the coal, water and oxygen react, but in a high-temperature reducing atmosphere. With the GE systems, the high degree of stress and corrosion on the nozzles historically has meant the nozzles need to be changed every 30-90 days, in a process that requires the gasifier to be shut down. The gasifier vessel is constructed of abrasive-resistant and thermal insulating bricks and cast material. The refractory that lines the inside of the vessel needs to be replaced every 18-24 months. This requires an outage that can take several weeks.

For these reasons, several economic studies indicate improved economics (lower life-cycle cost of electricity) when a spare gasifier is installed to keep the unit running when the above maintenance is performed. This decision to spend the additional $50-$75 million for the spare gasifier will be based on the expected improvement in availability. AEP has not yet decided whether to install the spare gasifier.

Other Factors – Commercialization and Technology Development

IGCC investment also furthers the commercialization of the technology. As such, it moves IGCC further along the technology learning curve, resulting in lower plant costs sooner than would be the case otherwise. The effect is difficult to measure, not to mention the specific share of this effect that is due to the construction of the 600-MW plant in Ohio.

However, most experts generally maintain that base IGCC costs could fall to levels similar to PC over the next decade as commercialization occurs. Thus, the impact of the first IGCC coal plants (such as the AEP-Ohio plant) could be significant and would result in even greater long-term benefits.

Discussion of Alternative Options

Pulverized Coal

Pulverized coal-fired plants are often considered to be the workhorse of the U.S. electric power generation infrastructure. In a PC plant, the coal is ground into fine particles that are blown into a furnace where combustion takes place. The heat from the coal combustion generates steam to drive a turbine that drives a generator to make electricity. Major byproducts of combustion include sulfur dioxide, nitrogen oxide, carbon dioxide, and ash, as well as various forms of elements in the coal ash, including mercury. Several of the combustion byproducts must be removed from the system before the flue gas leaves the stack.

The steam cycle for the pulverized coal-fired units, which determines the efficiency of the generating unit, falls into one of two categories, *subcritical* and *supercritical*. Subcritical main steam conditions are typically 2,400 psig/1,000°F, with a single reheat to 1,000°F, while supercritical steam cycles typically operate at main steam pressures of 3,600 psig, with 1,050-1,100°F main steam and reheat steam temperatures. Some designs are being developed above 1,100°F, called *ultrasupercritical* cycles, but they still are in the development stage and are not commercially available.

Subcritical PC designs are generally preferred for load-following or cycling operation, where they are used to change their output as the electricity demand fluctuates, since subcritical systems can achieve higher efficiencies during reduced load operation than comparable supercritical units. The initial capital costs of subcritical units are lower than a comparable supercritical unit by up to about 4-6 percent, but the overall efficiency of the subcritical design is lower than the supercritical design, by about 3-4 percent. Since the supercritical design achieves high efficiency at full load, supercritical units are generally superior choices for baseload operation.

The selection between supercritical versus subcritical design still depends on many other site-specific factors including fuel cost, emission control requirements, capital cost, load factor, and expected reliability and availability. AEP has recognized the benefits of the supercritical design for many years. All 18 of the units in the AEP East system built since 1964 have used the supercritical design.

Circulating Fluidized Bed

A Circulating Fluidized Bed (CFB) plant is similar to a PC plant except that the coal is crushed rather than pulverized, and the coal is combusted in a reaction chamber rather than the furnace of a PC boiler. Because CFB boilers are generally more suited for low-rank high-ash coals such as the lignite coals common in the western states, the economics of CFB boilers is not included in this paper.

Natural Gas Combined Cycle

An NGCC plant combines a steam cycle and a gas cycle to produce power. Hot gases (~1,100°F) from a combustion turbine exhaust pass through a heat recovery steam generator, where they are cooled to about 250°F and produce steam as a result. The steam drives a turbine generator that produces about one-third of the power, with the combustion turbine producing the other two-thirds.

The main features of the NGCC plant are high reliability, lower capital costs, excellent operating efficiency, low emission levels, and shorter construction period than coal-based plants. In the past 8-10 years, NGCC plants were the most widely selected to meet new intermediate and baseload needs due to these features and very favorable natural gas prices. However, as gas prices have risen the cost of electricity from NGCC plants has been very high, and attention has been re-directed to coal-fired alternatives for baseload generation.

III. Carbon Capture and Sequestration Impact on Generation Technologies

Carbon capture technologies available in IGCC facilities are critical factors supporting reliance on IGCC. In its own right, IGCC technology is superior in terms of emissions mitigation. But today's political and natural environments all indicate the high likelihood of future carbon capture requirements legislated by federal laws or regulations, and possibly additional state requirements as well. And it is in this area that, absent revolutionary improvements in technology, IGCC leaves the other technologies far behind.

Reducing carbon dioxide emissions from a fossil-fuel technology can be accomplished in three ways: reducing the carbon content of the fuel, removing the carbon dioxide from the flue gas or increasing generating efficiency.

Reducing the carbon content of fuel can be accomplished by either switching from coal to natural gas (since natural gas has approximately 20 percent less carbon than coal, and correspondingly greater hydrogen content), or by removing the carbon from the relatively low volume of synthetic gas before it is combusted, as would be the case for CO_2 removal in an IGCC system.

Removing the CO_2 from the flue gas is a very expensive process. Currently, the most likely technology to be used to "scrub" the CO_2 from the flue gas would be by using a monoethanolamine (MEA) or methyldiethanolamine (MDEA) absorption process. This process has a high capital cost (approximately $800/kW to $1,000/kW) and a high efficiency penalty of more than 30 percent.

Increasing the generating efficiency of a coal-based plant has its practical limitations. Efficiency improvements will not result in significant CO_2 emission reductions.

Studies have indicated that the energy penalty for CO_2 removal from an IGCC system would likely be in the order of a 20 percent efficiency penalty, and a 35 percent capital cost penalty. Other technologies are being developed for carbon capture, however these technologies remain in the early stages of development. Significant breakthroughs will be required before we can see the benefit of many of these other innovative technologies for the capture of CO_2.

Comparison of Technology Costs and Technical Parameters

Tables 1a and 1b below compare the capital costs and technical parameters of IGCC, PC and NGCC units. (Because CFB combustion technology is generally not deemed suitable for Eastern bituminous coals, it is not an appropriate consideration for this region of the country. Therefore, it is not considered in any of the data provided by AEP in relation to this project.)

Table 1a
Comparisons of IGCC, PC and NGCC
Without CO_2 Capture

Technology	IGCC	PC	NGCC
Net MW	600	600	600
Heat Rate Btu/kWh	8,700	8,690	7,200
Total Plant Cost, $/kW	1,550	1,290	440

Table 1b
Comparisons of IGCC, PC and NGCC
With CO_2 Capture

Technology	IGCC	PC
Net MW	530	460
Heat Rate Btu/kWh	10,700	11,300
Total Plant Cost, $/kW	1,950	2,150

IV. Economic Analysis of IGCC Coal Compared to Power Generation Alternatives

A central tenet of the economic evaluation of new power plant investment typically is a comparison of the total cost of electricity to the market price for electricity. There is little to no liquidity in the forward market for power in the year 2010 and after. As such, market prices obtained from market quotes are generally not available, and where available, are not particularly meaningful. Therefore, the cost of new generation is the proxy for the market.

A sounder approach, therefore, in this instance is to look at power generation alternatives to IGCC, such as pulverized coal and NGCC, with the view that market will be set by the lowest cost alternative to produce power in the long run. This is a reasonable assessment since, in the long run, power plants will not be built to meet demand unless prices provide a return on investment and cover the costs of building and operating the plant over time.

Further, the Company believes that by 2010, the present oversupply of generating capacity will be brought into balance with growing demand in the AEP-East region. This supply/demand balance should result in prices being set approximately by long run costs of generating power after 2010.

Comparative Economics of Coal Technologies, Including Air Emission Costs

Therefore, determining the relative economics of IGCC requires a comparison with the alternative least-cost baseload generating options.

Table 2 below shows the cost comparison of IGCC levelized costs compared to PC and NGCC in Ohio. While IGCC today is somewhat higher in levelized cost than PC ($56.2/MWh vs. $52.2/MWh), it is significantly lower in cost than NGCC, based on AEP's forecasts of natural gas costs. The levelized busbar costs not only include levelized capital, O&M and fuel, but also include the impact of new air emission regulations on the costs of the technologies.

Table 2
Comparative Economics of New Generation Options
(In Levelized Nominal Dollars, Beginning in 2010)

	IGCC*	PC**	Gas CC***	IGCC w/ CCS****	PC w/ CCS*****
Total Plant Cost ($/kW)	1,550	1,290	440	1,950	2150
Capital – Levelized ($/MWh)	31.7	26.4	8.2	45.1	57.3
Total Levelized O&M ($/MWh)	9.1	8.9	3.5	16.6	19.9
Levelized Fuel ($/mmBtu)	1.61	1.61	7.34	1.61	1.61
Levelized Fuel ($/MWh)	14	14	52.8	17.2	18.2
Levelized Emission Cost ($/MWh)	1.5	2.9	.1	.6	.6
Total Levelized Cost ($/MWh)	56.2	52.2	64.7	79.4	95.9

* IGCC: Integrated gasification combined cycle
** PC: Pulverized coal
*** Gas CC: Gas combined cycle
**** IGCC w/CCS: IGCC with carbon capture/sequestration
***** PC w/CCS: PC with carbon capture/sequestration

Under EPA's recently promulgated Clean Air Interstate Rule (CAIR) and the Clean Air Mercury Rule (CAMR), which cover SO_2, NOx and mercury emissions, most fossil fuel power plants will be subject to a cap on their overall annual emissions of SO_2, NOx and mercury, with emissions trading permitted. Therefore, additional emissions costs resulting from plant operations also are included in the levelized cost calculations. Because the IGCC plant's SO_2 and mercury emissions are generally lower than the PC plant's, its emissions costs are also lower. This narrows the cost difference between today's technologies. Emission costs reflect market SO_2 values and estimated values for the annual NOx and mercury markets.

Other Economic Factors That Could Lower IGCC Costs

In addition to the economic analysis above, there are other factors that could lower the relative costs of IGCC and improve the differential between IGCC and PC. These factors have not been quantified in the analysis above but should be considered in the overall assessment of IGCC:

- **Fuel flexibility:** IGCC provides some advantages over PC with regard to fuel flexibility. For example, it is possible that petroleum coke may be produced in Ohio in the not-too-distant future. Blends of petroleum coke would lower overall fuel costs and could be easier to use in an IGCC plant than in a PC plant.
- **Marketable by-products:** IGCC can produce marketable by-products when the coal is gasified, such as sulfur or sulfuric acid and slag. These potential by-products were not included in the economics of IGCC.
- **Product flexibility:** Owing to the IGCC plant's low variable costs, AEP anticipates operating its IGCC plant whenever it is available to meet electricity demand. However, it is possible during some periods when demand and prices both are low that the plant may not be called upon to produce power in PJM. AEP is currently

studying whether production of other marketable products such as methanol and diesel during idle generation periods might enhance the overall economics of the plant.

Long-term Economics Including CO_2 Option Value

IGCC has long run costs similar to PC, when taking into account potential costs associated with possible future greenhouse gas legislation. Because an IGCC plant provides AEP with the option to capture and sequester carbon, an IGCC plant has an inherent "option" value compared to PC or NGCC, where these costs are prohibitive. While an option also exists to potentially capture and sequester carbon from a PC plant, its value is considerably lower in a PC plant, owing to its very high costs within that technological framework.

While the prospects of passage of greenhouse gas legislation in the United States are not imminent in the next four years, there is a greater likelihood that passage will occur after that time. If and when there is legislation, it is likely to include some form of greenhouse gas/carbon dioxide constraints or cap, with emissions trading permitted. Thus, similar to SO_2 and NOx, as well as mercury in the future, there is likely to be a market for CO_2 emission allowances and a value associated with CO_2 emission reductions or offsets at power plants, as well as other sources of greenhouse gases.

This analysis used a range of carbon dioxide allowance prices reflecting the potential stringency and timing of possible future legislation. Using these prices and the costs of the new generating technology options, we have conducted a probabilistic decision analysis.

We have assumed three potential future states of the world with equal probabilities (30 percent each) and one additional very stringent scenario (with a 10 percent probability.)

1. No CO_2 legislation,

2. CO_2 legislation with low carbon prices, and

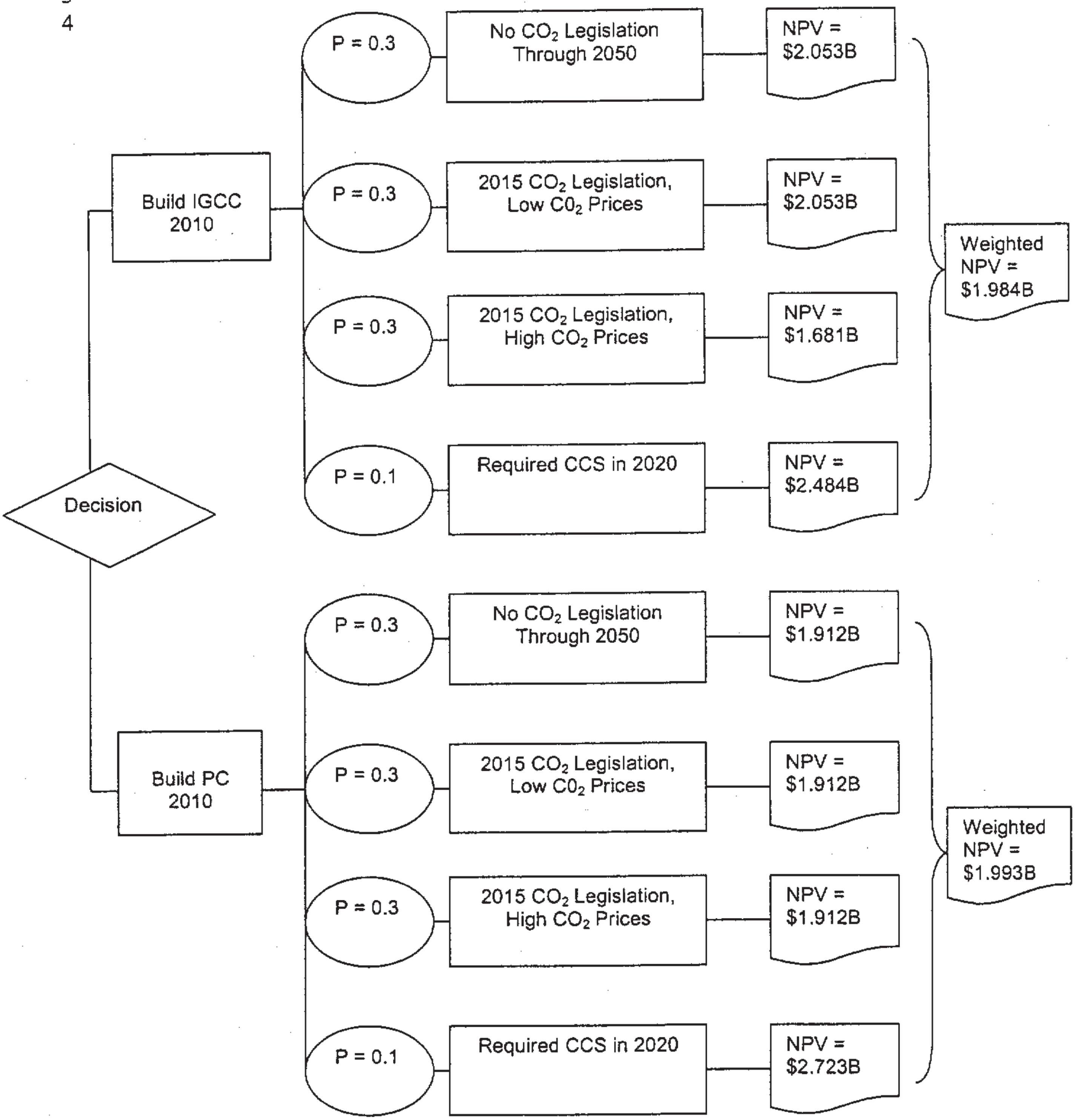
3. CO_2 legislation with high carbon prices.

4. CO_2 legislation requiring carbon capture and sequestration on all new coal plants in 2010 or later by 2020.

The results of the evaluation, shown in Fig. 1, indicate that the long run costs (in net present value [NPV] terms) of an IGCC power plant are similar to those of a PC plant.

Thus while today's costs and today's environmental requirements yield higher costs for an IGCC plant than a PC plant, factoring in the option value of carbon capture and sequestration if the IGCC plant is built would result in the net costs of the IGCC being similar to a pulverized coal unit. Fig. 1 shows the calculation of the net present value costs under the alternative future scenarios. This simple analysis indicates that if future climate change legislation is factored into the analysis, IGCC is a more economic choice than PC by $9 million in NPV terms.

Fig. 1
Effect of Potential CO_2 Costs on NPV Cost of New Power Plants



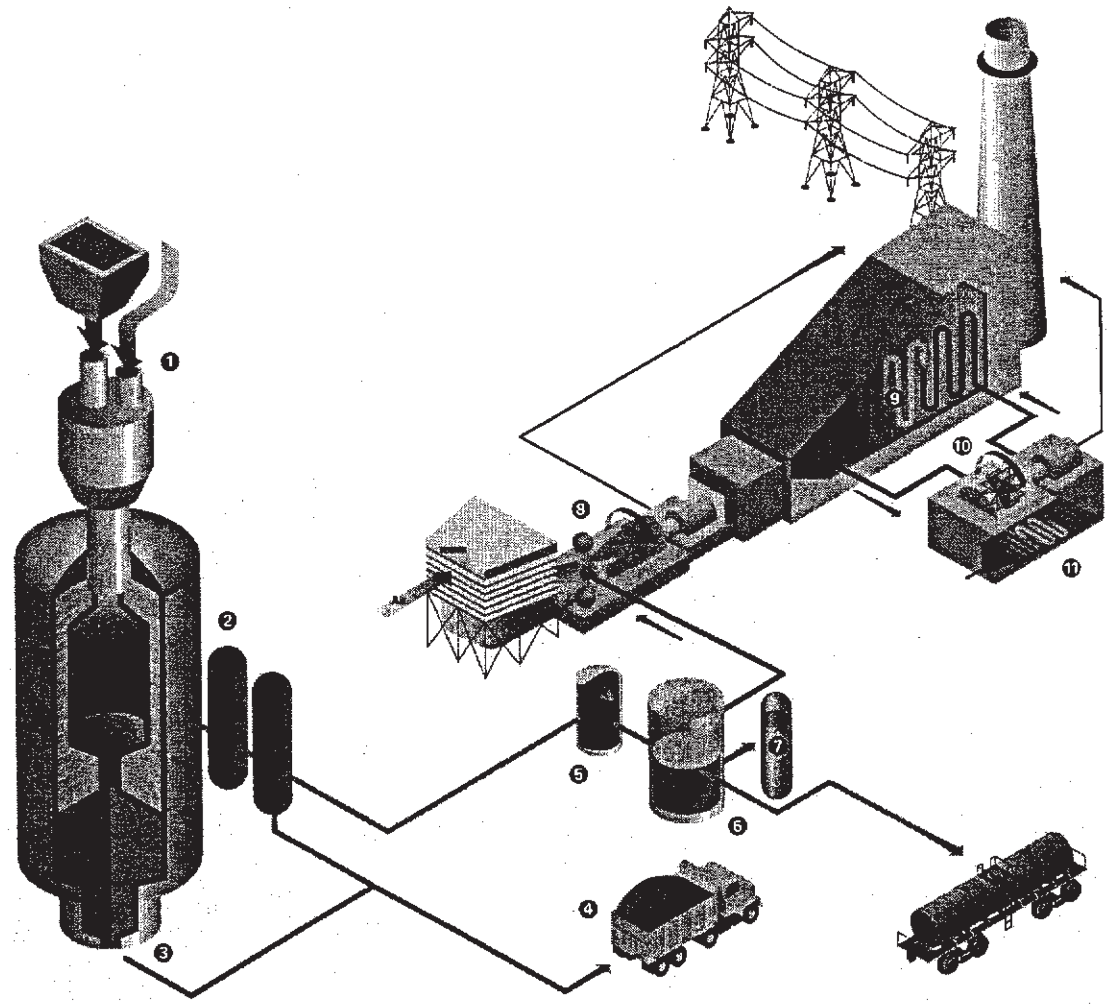
Economic Summary

When considering only current environmental regulations, the cost of electricity for IGCC is somewhat more expensive than PC and less expensive than NGCC. However, when the CO_2 option value of IGCC and PC are considered, IGCC and PC have very similar economics.

Further, an IGCC power plant is a superior choice for Ohio when considering a number of other factors that were not quantified in the assessment. These include fuel flexibility, by-products and product flexibility, as well as furthering the commercialization and lowering the long run costs of the technology for future IGCC applications.

Appendix A

IGCC Process Schematic



Legend:

1. Coal, water and oxygen are fed into a high-pressure gasifier, where the coal is partially combusted and converted into syngas.

2. The ash in the coal is converted to inert, glassy slag.

3. The syngas produced in the gasifier is cooled and cleaned of particles.

4. The slag and other inert material may be used to produce other products or may be safely managed in a landfill.

5. Next, the syngas passed through a bed of activated charcoal, which captures the mercury.

6. The sulfur is removed from the syngas and converted to either elemental sulfur or sulfuric acid for sale to chemical companies or fertilizer companies.

7. The syngas can either be burned in a combustion turbine or used as a feedback for other marketable chemical products.

8. The syngas is fired in a combustion turbine that produced electricity.

9. The hot exhaust from the gas turbine passes to a Heat Recovery Steam Generator (HRSG).

10. Steam produced in the HRSG, along with additional steam that has been generated throughout the process, drives a steam turbine, which also produces electricity.

11. The steam from the turbine cools and then condenses back into water, which is then pumped back into the steam generation cycle.