

CONCEPT PAPER

3Party Covenant IGCC Financing Proposal

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This pre-release consultation paper describes the concept of a 3Party Financing Covenant to stimulate investment in advanced Integrated Gasification Combined Cycle (IGCC) coal generation technology. The paper is designed to facilitate review of the concept by financial and regulatory experts to assist the authors in developing an IGCC financing and regulatory proposal to be presented at a Kennedy School of Government symposium on February 11, 2004, co-sponsored by: the Belfer Center for Science and International Affairs and Center for Business and Government, Kennedy School of Government, Harvard University; the Center for Clean Air Policy; and the National Commission on Energy Policy.

Background

The U.S. has more coal than any other country in the world with proven reserves of about 275 billion tons—over a 250-year supply at current consumption levels. About 90% of coal consumed in the U.S. is used to generate electricity, with coal-fired power plants accounting for about 51% of U.S. electricity generation. U.S. coal reserves are located principally in Appalachian, Midwest, Rocky Mountain, Southern states and Alaska (Figure 1).

There are powerful economic and energy security reasons for continued U.S. reliance on coal as a primary generation fuel, including abundant domestic supplies, stable prices, electricity reliability, avoidance of adverse impact on natural gas availability and price for other sectors of the economy, and the opportunity for technology leadership and export. However, environmental concerns, deregulation, and financial uncertainty in changing electricity markets have virtually stopped new coal capacity additions in the U.S. In the last three years, a total of 140 GW of new capacity has come on line. About 95% of the new capacity is natural gas-fired, and none of it is coal-fired (Figure 2).

A significant concern with shifting to more natural-gas-fired generation is that natural gas consumption by electric generators puts additional pressure on natural gas supply and prices. Natural gas prices through August 2003 were two to three times above historic averages. These high natural gas prices caused widespread, adverse impacts on the U.S. economy and economic competitiveness, including significant job losses in manufacturing and chemicals industries.¹ Alan Greenspan, Chairman of the Federal Reserve System, recently stated:

¹ The economic consequences of high prices are described in the House Speaker's Task Force for Affordable Natural Gas report, which states: "Because domestically produced natural gas is so vital to our nation's energy balance, rising prices make our nation less competitive. When prices rise, factories close. Good, high paying jobs are imported overseas. Today's high natural gas prices are doing just that. We are losing manufacturing jobs in the chemicals, plastics, steel, automotive, glass, fertilizer, fabrication, textile,

The long-term equilibrium price for natural gas in the United States has risen persistently during the past six years from approximately \$2 per million Btu to more than \$4.50... The updrift and volatility of the spot price for gas have put significant segments of the North American gas-using industry in a weakened competitive position. Unless this competitive weakness is addressed, new investment in these technologies will flag.²

One reason for the dearth in new coal capacity is that coal combustion in traditional pulverized coal (PC) power plants produces harmful by-product emissions that raise local, regional, and global environmental concerns. In addition to sulfur dioxide (SO₂), nitrogen oxides (NO_x), and mercury (Hg) emissions that have local and regional impacts, carbon dioxide (CO₂) emissions from coal combustion are a concern because of their link to global climate change. Continued and expanded coal use for electricity generation around the world is projected by the Energy Information Administration (EIA) to increase CO₂ emissions from coal combustion 45 percent by 2025 (Figure 3). Concern about this trend has helped fuel opposition to new PC plant construction in the U.S. and is one of the factors that have made it increasingly difficult to justify or finance new coal power plant projects.³

High natural gas prices, concerns about energy security, and environmental concerns have together helped renew interest in policy approaches to support development and commercial deployment of advanced clean coal generation technologies, especially IGCC. IGCC technology combines a coal gasification system with a combined cycle power block to produce cleaner and more efficient generation than conventional, PC boiler technology. The gasification system converts coal (or other solid or liquid feed stocks such as petroleum coke or heavy oils) and steam into a gaseous “syngas,” which is made up predominately of hydrogen (H₂), carbon dioxide, and carbon monoxide (CO). The combustible syngas is used to fuel a combined cycle generation power block, which is a technology that is in wide use throughout the world, and is the technology utilized by most new natural gas-fired generation facilities. The first generation cycle involves the combustion of the primary fuel, which can be oil, natural gas, or in this case, syngas, in a combustion turbine (CT). The CT powers a generator, generating electricity, and the exhaust gases, which are usually around 900 degrees, are captured and directed into a Heat Recovery Steam Generator (HRSG). In the second generation cycle, the HRSG

pharmaceutical, agribusiness and high tech industries.” House Energy and Commerce, The Task Force for Affordable Natural Gas, Natural Gas: Our Current Situation (September 30, 2003).

² Testimony of Chairman Alan Greenspan before the Committee on Energy and Natural Resources, U.S. Senate (July 10, 2003).

³ The other fundamental reason is the higher cost of building coal plants, which results in greater capital exposure for developers of coal power plants versus natural gas power plants. In recent years, developers built many natural gas power plants in deregulated markets expecting high returns on their relatively low capital investment. As noted below, the recent softening of electricity markets and rise in natural gas prices have had a very negative impact on the economics of these plants.

utilizes the energy contained in the exhaust to generate steam which powers a second generator. IGCC systems have lower NO_x, SO₂, and mercury (Hg) emissions than conventional coal power plants and can be designed or retrofitted to separate and capture CO₂ emissions to address climate change concerns.

There is broad support for commercialization of IGCC. In February 2003, President Bush announced his support for a \$1 billion IGCC commercial project (Future Gen) with 80% public funding and 20% private investment, and the Department of Energy (DOE) has major research initiatives on-going to optimize IGCC generation technology. DOE has indicated:

It is the intent of the DOE to foster the commercialization of gasification systems so that the environmental and efficiency advantages offered by gasification become broadly available and gasification becomes the economic choice for power and energy projects.⁴

The energy bill currently being considered in Congress commits, for the first time, the federal government to deployment of gasification projects and authorizes over \$1 billion for IGCC technology and project development. There is also strong support in the environmental community for deployment of IGCC technology. David Hawkins of the Natural Resources Defense Council has testified that:

If coal is to continue as a major player in the U.S. and elsewhere for more than a few decades it will only be if technologies like IGCC, that make it feasible to store carbon permanently in geologic formations, are commercially deployed at sufficient scale to buy down their costs to fully competitive levels. The U.S. is one of the few countries in the world with the resources to carry out such a program in a short period of time.⁵

Despite the promise of the technology, IGCC projects today face 10-20% higher capital costs and, because the technology is less mature, greater operating risks than conventional, PC generation. Although gasification technology is utilized at over 160 refining and chemical industry facilities utilizing primarily petroleum feedstocks, coal gasification with integrated electricity generation has only been operated at a commercial scale at a handful of facilities (two in the U.S. funded in part by DOE) and is not yet a mature commercial technology. The next generation of IGCC facilities will need to overcome construction and operating challenges and, in order to operate at the high availabilities expected of base-load coal power plants (90+%), may need to be designed with redundant equipment applications that raise capital costs.

⁴ Department of Energy, National Energy Technology Laboratory, Advanced Gasification Product Description, www.netl.doe.gov/coalpower/gasification/adv-gas/description.html (November 10, 2003).

⁵ Testimony of David Hawkins, Director of the Natural Resources Defense Council Climate Center, presented before the U.S. Senate Committee on Environment & Public Works (June 12, 2002).

Under these circumstances, near-term commercial deployment will depend on development of regulatory structures and financial incentives to overcome higher risk and costs to attract private investment. The 3Party Covenant program described below could stimulate IGCC investment this decade by significantly reducing capital costs and risks born by investors. The approach is designed to make IGCC technology cost competitive with PC-fired and natural-gas-fired generation.

3Party Covenant Overview

The 3Party Covenant is a financial and regulatory arrangement among a federal agency, a state public utility commission (state PUC), and an equity investor to finance the development of a qualifying IGCC power plant.

The 3Party Covenant is designed to achieve the following financial objectives:

- Capital availability to finance plant;
- Lower cost of capital through lower interest rates and higher debt/equity ratio;
- Lower project development cost through on-going recovery of capital costs during construction;
- Dedicated revenues to reduce financial risk and cover return of capital, cost of capital, taxes, and operating costs after plant completion;
- Minimized scoring of federal loan guarantee as budget expenditure; and
- Production of IGCC power at a cost competitive with PC or natural-gas power.

The program for implementing the 3Party Covenant would be established through federal legislation authorizing a federal agency (presumably DOE) to guarantee long-term debt used to finance qualifying IGCC projects. The federal guarantee allows for debt financing of 80% of the development cost of a qualifying IGCC project. The guarantee pledges the full faith and credit of the United States Government, and the guaranteed debt trades as part of the trillion dollar federal agency bond market. Typically, interest rates for long-term federal agency bonds are higher than for U.S. Treasury Bonds of similar maturity and approximately 100 basis points lower than for medium grade utility bonds.⁶

To enable a project to participate in the federal guarantee program, a state voluntarily opts into the program by establishing certain utility regulatory provisions for IGCC projects. Specifically, a state PUC (or other utility rate making authority in the case of public power), acting under state enabling authority, agrees to assure dedicated revenues to qualifying IGCC projects sufficient to cover return of capital (depreciation and amortization), cost of capital (interest and authorized return on equity), taxes, and operating costs (e.g., operation, maintenance, and fuel costs). The state PUC provides this

revenue certainty through utility rates in regulated states, or through non-bypassable wires charges in deregulated states, by certifying (after appropriate review) that the plant qualifies for cost recovery and establishing rate mechanisms to provide recovery.

The equity investor (developer) under the 3PartyCovenant is likely to be either a utility or an independent power producer that secures a long-term power purchase contract with a utility. The developer contributes equity for 20% of project costs and obtains vendor guarantees to develop, construct, and operate the IGCC plant.

Key Elements and Economics

The 3Party Covenant program couples a federal loan guarantee program with state PUC ratemaking authority to alter the capital structure and enhance the credit rating of an IGCC project financing in a way that significantly reduces the cost of capital and total capital investment required to build the plant.⁷ Cost of capital and return of capital (principal amortization of debt and repayment of equity) typically constitutes over 60% of the energy production costs from a new coal PC or IGCC plant. Key elements of the 3Party Covenant program and its benefits are discussed in detail below.

Federal Loan Guarantee Terms and State PUC Participation

Under the 3Party Covenant, a government loan guarantee administrator (presumably within DOE) is established and responsible for ensuring that construction, operating, and market projections of a proposed IGCC project demonstrate economic feasibility and the ability to meet debt service obligations. The administrator also sets the financing terms and conditions of a federal guarantee for the debt financing, which include equity investor/owner and vendor performance guarantees to provide a measure of protection to the loan.

Most importantly, the loan guarantee is conditioned upon the state adopting procedures under which the state PUC: certifies before construction begins that an IGCC project meets federal and state requirements; periodically approves each portion of the project as construction proceeds; and provides strong assurance of timely cost recovery for each approved portion and, once the plant is completed, for recovery of operating costs. In a state with traditional utility rate regulation, cost recovery is through an adjustment clause in the rates paid by all retail customers of the regulated utility. (Indiana already has adopted procedures with many of these features. See, e.g., IC 8-1-8.7-3 (certification of

⁶ The authors are conducting further research to confirm these interest differentials.

⁷ The term “cost of capital” is used here to describe financing costs, i.e., interest and return on equity. The term “total capital investment” is used to describe the total cost of building a power plant, including interest and other expenses incurred during construction. Total capital investment may be called “total plant cost” or “overnight capital cost” in other works.

clean coal technology), 8-1-8.7-7 (on-going review), 8-1-8.7-8 (assurance of recovery of approved costs), and 8-1-8.8-11 (financial incentives for clean coal technology).) In a state with deregulated retail electric service, cost recovery is through an adjustment clause in a non-bypassable wires charge paid by all retail electric customers, e.g., in the service area of the distribution utility selling the IGCC power. (Ohio already provides for non-bypassable wires charges for transition costs and certain public benefit costs. See, e.g., ORC 4928.37(A)(1)(b), 4928.61, and 4933.83.)⁸

Specifically, the state procedures must provide as follows:

1. Before any construction begins, the state PUC reviews the equity investor's plans for the coal IGCC plant in order to determine whether the plant is in the public convenience and necessity, has reasonably projected costs, and is economically feasible (with a federal guarantee and state cost recovery mechanism).
 - a. Based on satisfactory determinations on these matters, the state PUC then issues a certificate for the construction of the new plant.
 - b. In issuing the certificate, the state PUC determines the cost of capital for the project. Periodically (e.g., annually) the state PUC reviews and updates the cost of capital for the project.
2. After issuance of a certificate and as construction progresses, the state PUC periodically reviews on an expedited basis, and approves as appropriate, the prudence of the constructed portion and the associated costs.
 - a. After the state PUC approves a portion of the plant, the cost of capital for the preconstruction and construction expenditures (which are sometimes referred to as "construction work in progress" or "CWIP") for that portion of the plant are recoverable on an on-going basis through an adjustment clause. The charge under the adjustment clause is recalculated and reviewed as part of the state PUC's expedited review of that portion of the plant.
 - i. The duration of each periodic (e.g., three to six month) review proceeding is limited (e.g., to three months). As a result, such cost of capital will be recovered within a relatively short period (e.g., three to nine months) after incurrence of the associated capital expenditures.
 - ii. Note that since the cost of capital is recovered on an on-going basis during construction, it does not accrue and is not added to the capital

⁸ The authors are in the process of evaluating existing state laws in both regulated and deregulated states and determining the extent to which the procedural and cost recovery requirements under the 3Party Covenant can be met under existing law. The authors have initially focused on the utility regulatory systems in Indiana and Ohio, as examples, and will expand the research to additional states.

investment in the plant. Although the on-going recovery of the cost of capital during construction increases costs to customers in the short run, lifetime costs on a nominal and present value basis are reduced. Such on-going recovery reduces development costs, which otherwise would be financed over 30 years, by about 9% and, under the 3Party Covenant, offsets about 34% of the construction cost differential between IGCC and PC (see Figure 4).

b. After the state PUC approves each portion of the preconstruction and construction expenditures, recovery of such capital expenditures and associated cost of capital cannot thereafter be challenged, in the absence of fraud or concealment. For example, issues concerning excessive cost, inadequate quality control, failure to complete, or inability to operate properly cannot be raised. In this way, the state PUC's review and protective approval are updated during the construction period.

i. If construction of the new plant is terminated before plant completion, any portion of the preconstruction and construction expenditures that was not approved is recoverable (along with associated cost of capital) only upon a showing that such portion was necessary and prudent and in the absence of fraud, concealment, or gross mismanagement.

ii. After completion or termination of construction of the plant, recoverable preconstruction and construction expenditures are depreciated or amortized over the appropriate period and, along with the associated cost of capital, recovered through an adjustment clause. The charge under the adjustment clause is recalculated and reviewed periodically by the state PUC on an expedited basis.

iii. Note that the availability of federal guaranteed long-term debt is coordinated with the on-going review process so that, as each portion of the capital expenditures is reviewed and cost recovery is approved, a disbursement of the federal guaranteed loan becomes available for the debt-funded share of that portion of the expenditures.

3. After completion and commencement of operation of the new plant, all taxes and operating costs (e.g., operation, maintenance, and fuel costs) of the new plant are recoverable through an adjustment clause. The charge under the adjustment clauses is recalculated and reviewed periodically by the state PUC on an expedited basis.

Under the above-described procedures, state PUC certification and approval results in an assured, dedicated revenue stream to cover the construction, operating, and market risks of the IGCC plant. From the standpoint of the federal government, this assurance

provides enhanced credit worthiness and strong protection against loan default. From the standpoint of the equity investor, this assurance enables underwriting of the federally guaranteed loan in the context of a higher debt-equity ratio (80-20) than available under conventional financing terms (55-45). From the standpoint of purchaser of the long-term debt, the federal guarantee provides a federal agency bond rating for the debt.

Economic Analysis

To assess how the 3Party Covenant affects the economics of IGCC, the authors have developed an economic analysis to compare total capital investment, cost of capital and energy costs of IGCC against natural gas combined cycle (NGCC) and PC power plants (Figure 4).

The analysis looks at three different financing scenarios:

- 1) Assuming the plants are built in a deregulated state as merchant facilities;
- 2) Assuming the plants are built under traditional regulated utility financing; and
- 3) For IGCC, assuming a 3Party Covenant with a federal loan guarantee in a regulated or deregulated state.

The analysis begins with base-case assumptions for cost and performance characteristics for each type of plant. These assumptions, which are summarized below, are intended to characterize typical plants based on current technology. The assumptions were developed from published government, academic, and industry reports and discussions with vendors (Figure 5).

NGCC Plant

The analysis assumes a 500 MW NGCC facility with a total engineering, procurement and construction (EPC) cost of \$510/kW. This cost represents the cost of erecting the plant including contingencies, but not considering construction financing. The analysis assumes a two-year design and construction period that results in a 5% increase in the capital cost due to construction financing. The total required capital investment is therefore \$536/kW (or, for a 500 MW plant, \$268 million). The plant is assumed to operate with an efficiency of about 50% (6,800 btu/kWh heat rate) and have operation and maintenance (O&M) costs of 0.25 cents/kWh.

The most important economic variable in determining the cost and relative competitiveness of NGCC generation versus coal generation is the cost of natural gas. Unfortunately, the price of natural gas is highly variable and difficult to predict. Changing natural gas prices dramatically affect the economics of NGCC by changing

variable costs and changing how much a plant operates during the year.⁹ In 2003, the average delivered price of natural gas to electric generators is over \$5.00/mmBtu. Most forecasts indicate natural gas prices will drop below this level, but remain well above historic averages. The price assumed in the current economic analysis is \$4.50/mmBtu, which is consistent with the long-run equilibrium price according to a recent statement by Alan Greenspan.¹⁰ This price is assumed to result in a 50% capacity factor for the plant, which is probably very optimistic. Sensitivity analysis will be conducted to evaluate economic results at different natural gas prices and capacity factors to determine natural gas prices that result in break even economics between the NGCC and coal plants under different financing assumptions.

PC Plant

The PC plant is assumed to be a new 600 MW super critical boiler with a total engineering, procurement and construction (EPC) cost of \$1,150/kW. The plant is assumed to take four years to design and construct, which results in a 10% cost increase (primarily associated with construction financing), bringing the total capital investment to \$1,265/kW (\$759 million). The plant is assumed to operate at 40% efficiency (8,600 Btu/kWh)¹¹ and have O&M costs of 0.75 cents/kWh. Coal is assumed to cost \$1.24/mmBtu delivered.

The total capital investment and efficiency estimates for the PC plant account for the cost and parasitic load associated with add-on emissions control equipment that would be required under current environmental requirements. A new PC plant would likely be outfitted with Flue Gas Desulfurization (FGD) for SO₂ control, Selective Catalytic Reduction (SCR) for NO_x control, and Electro-Static Precipitators (ESPs) or bag houses for particulate control and may, under future environmental requirements, include activated carbon injection (ACI) technology for mercury control. The construction and operation of all of this equipment raises capital and operating costs and creates additional uncertainty about operating performance.

⁹ The amount of time a plant operates is determined by how its variable costs compare with the variable costs of other available power plants, which affects where the plant is in the dispatch order. Therefore, changes in natural gas costs change the capacity factor of a NGCC plant. The less a plant operates, the less revenue is generated to cover fixed costs and therefore the less economic the plant becomes.

¹⁰ Testimony of Chairman Alan Greenspan before the Committee on Energy and Natural Resources, U.S. Senate (July 10, 2003).

¹¹ Supercritical PC boilers can operate at this level of efficiency, but it may be somewhat optimistic given the amount of add-on pollution control equipment needed on the boilers, which reduces plant efficiency. Nonetheless, for this purpose, assuming an efficient PC plant is a conservative assumption for analyzing the plant's relative economics under different financing assumptions, and setting the efficiency for PC and IGCC plants at comparable levels helps isolate the impact of financing assumptions.

IGCC Plant

The IGCC facility is assumed to be a new 600 MW plant with a dual-train configuration (two gasifiers with each feeding a combined cycle power block) and a third backup gasifier to assure high availability. This setup is assumed to have an EPC cost of \$1,400/kW and take four years to design and construct. The construction financing is assumed to add 10% to the cost, bringing the total capital investment required to \$1,540/kW (\$924 million). The plant is assumed to operate at the same efficiency as the PC plant (40%, or 8,600 btu/kWh).¹² The facility is assumed to have O&M costs of 0.88 cent/kWh (basically comparable to the PC plant) and to purchase fuel for the same price of \$1.24/mmBtu delivered.

The gasification process at IGCC facilities removes 98% of the sulfur from coal, eliminating the need for any add-on SO₂ emissions control. The NO_x emissions without add-on controls are comparable to those from a PC power plant with add-on controls and are able to meet new source permitting requirements for coal plants.¹³ Similarly, the particulate emissions are negligible and require no additional control. If future regulations require mercury control, the cost of mercury removal from IGCC facilities is projected to be about 10 times lower than the cost of mercury removal from PC plants. In addition, because IGCC plants have the potential of removing mercury from the syngas upstream of the gas turbine, rather than removing it from the flue-gas as required on PC plants, mercury removal in an IGCC power plant can be expected to be very high in removal effectiveness and reliable in design.¹⁴

These base-case assumptions result in IGCC capital investment/kWh that is 21.7% higher than for the PC plant, but very similar operating costs and characteristics for the two types of coal facilities. For each of the coal plants the capital component (financing and repayment of the total capital investment) represents about 60% of the total cost of producing energy.

Financing Assumptions

The objective of the economic analysis is to determine how different financing assumptions affect the relative cost of energy produced by the three types of facilities and, specifically, how the 3Party Covenant changes the relative economics of IGCC vs. PC (see Figure 4).

¹² See n.10. However, it is expected that as experience is gained with IGCC and turbine technologies are optimized for use with IGCC, the efficiency will improve to over 50%.

¹³ Work by NETL and EPRI indicates the NO_x emissions from IGCC facilities should be less than 10 ppm, or 0.028 lbs/mmBtu. See EPRI/NETL, Evaluation of Innovative Fossil Fuel Power Plants with CO₂ Removal (December 2000).

¹⁴ See NETL, The Cost of Mercury Removal in an IGCC Plants, p. 4-5 (September 2002).

Deregulated Merchant Financing--The initial financing scenario, assuming financing of a merchant plant in a deregulated market, assumes a developer requires a hurdle rate of 15% (which includes interest, amortization, and pretax return on equity). Under this scenario, total capital investment in cent/kWh is calculated by multiplying the total capital investment times the hurdle rate and dividing the result by the plant's annual kWh of generation based on its size and capacity factor.

Although this scenario shows similar coal plant economics as the traditional regulated financing scenario discussed below (see Figure 4), the authors do not believe it is reasonable to expect developers to build coal power plants (either PC or IGCC) as merchant facilities in the near term because the high capital investment required creates too much financial exposure and risk in uncertain electricity markets.¹⁵ Furthermore, the recent experience of developers who built natural gas merchant plants has dampened enthusiasm (among developers and on Wall Street) for merchant plant construction. Most, if not all, merchant NGCC power plants built since 1999, which were built with the expectation of high returns in deregulated markets, are today in economic distress due to the unexpected softening of energy markets and concurrent rise in natural gas prices.¹⁶ This experience will only serve to decrease the likelihood of future merchant coal plant development.

Traditional Regulated Utility Financing--Under the traditional regulated utility financing scenario, the analysis assumes a 55/45 debt/equity structure, based on information obtained in conversations with industry and state PUCs. It is assumed that the cost of 30-year utility debt is 6.5%, based on the price of medium grade utility bonds.¹⁷ The tax rate is assumed to be 38.2%, based on a 34% federal tax rate and 4.2% average state tax rate. It is assumed that the after-tax allowed equity return is 11.5%, which is consistent with typical allowed returns for regulated Midwest utilities. Achieving this after-tax return requires a pre-tax return of 18.6%. The result is a pre-tax, weighted average cost of capital for the projects of 11.9%.

3Party Covenant Financing--Under the 3Party Covenant IGCC financing, three changes are made in the financing assumptions from the traditional regulated scenario. First, it is

¹⁵ The authors are not aware of any coal-fired power plants that have been built in the U.S. as merchant facilities to date.

¹⁶ The Wall Street Journal reported on November 11, 2003 that: "The last time the electric industry was in this much trouble was 20 years ago, when utility customers and shareholders shouldered billions of dollars of cost overruns from nuclear-power plants. The latest downturn is the first since regulators a decade ago created a wholesale market where electricity could be bought and sold at competitive prices by unregulated, or merchant, suppliers. That means the current troubles are being borne by investors and bankers who financed the merchant companies' building spree."

¹⁷ See n. 5.

assumed that there is “100% CWIP,” which means that the cost of capital for pre-construction and construction expenditures is recovered on an on-going basis during construction. As a result, this cost does not accrue and does not need to be financed as part of the project. Therefore, the total capital investment required for the IGCC plant is essentially equal to the EPC cost of the IGCC plant, which is \$1,400/kW, or \$840 million.¹⁸ This adjustment for cost of capital recovery during construction represents a 9% reduction in the required capital investment. Second, the debt/equity structure is changed to 80/20, reflecting the more aggressive capital structure allowed by the terms of the federal loan guarantee. Finally, the cost of debt is assumed to drop to 5.5%, based on the typical cost of federal agency bonds, which are roughly 100 basis points below medium grade utility bonds.

Economic Results

The effects of these changes in the 3Party Covenant scenario are several fold. First, the adjustment for cost of capital recovery during construction reduces the total required investment, making the IGCC plant only 11% more expensive to build than the PC plant (down from almost 22%). Second, due to the change in capital structure to 80/20, the equity required for the IGCC plant decreases to \$168 million, substantially less than the \$342 million required for the PC plant under traditional regulated utility financing. Finally, the weighted average cost of capital in the 3Party covenant case is reduced to 8.1%, as compared to 11.9% in the traditional regulated scenario.

The net effect of these changes is to reduce the cost of energy for the IGCC plant 1.3 cents per kilowatt-hour, from 5.08 cents/kWh to 3.78 cents/kWh. This enables the IGCC plant to produce energy at 0.61 cents/kWh less than the PC plant in a traditional regulated financing scenario and 1.38 cents/kWh less than the NGCC plant in a traditional regulated financing scenario with \$4.50/mmBtu gas.

Based on this analysis, the 3Party Covenant financing of an IGCC plant becomes a more attractive development option than financing either PC or NGCC under merchant or traditional regulated utility financing scenarios.

CO₂ Capture and Sequestration

The preceding economic discussion assumes current environmental regulations in developing costs. However, another benefit of IGCC power plants is that they offer the potential for separating and capturing CO₂ for sequestration at a significantly lower cost

¹⁸ The authors recognize that, even with ongoing cost recovery, there is some lag time between the incurrence of preconstruction and construction expenditures and recovery of the cost of capital for such expenditures. The authors are considering how to reflect the impact of such lag time on the total capital investment for the IGCC plant.

than PC plants. Several studies have shown that if regulatory programs are put in place to curb power plant CO₂ emissions, the economics of IGCC become better than PC without any financing support (Figure 6).¹⁹ Moreover, while potential future CO₂ regulation is a risk to PC owners, it is a potential opportunity for IGCC owners who would profit from higher wholesale electricity prices and (assuming there were some sort of emissions trading regime like the Acid Rain SO₂ trading program under Title IV of the Clean Air Act) from the ability to market CO₂ allowances to PC owners unable to achieve reductions for the same price.

Federal Budget Implications

Because of the solid credit foundation that it creates, the 3Party Covenant structure will minimize the federal budget impact of the establishment of federal loan guarantees. The budgetary treatment of federal loan guarantee programs is governed by the Federal Credit Reform Act of 1990 (as amended). That act makes commitments of federal loan guarantees contingent on the appropriation of enough funds to cover the estimated cost associated with the guarantees, which is determined by the risk of loan default. The credit risk of existing federal loan guarantee programs varies widely. Some programs have average default rates of less than 2 percent; others have average default rates ranging from 10 percent to more than 20 percent.²⁰ The 3Party Covenant produces a lower credit risk because of the state PUC-approved revenue stream dedicated for the IGCC project and thereby should be scored at the low end of the range. The authors will be consulting with the Office of Management and Budget and the Congressional Budget Office to confirm this assumption and determine the how best to structure the loan guarantee program to minimize federal budget impacts.

State Adoption and State PUC Participation

Unlike the Public Utility Regulatory Policy Act (PURPA), where federal law required utilities to purchase power at avoided cost from qualifying facilities, the 3Party Covenant program is entirely voluntary. The federal government establishes terms and conditions for receiving the federal loan guarantee, but there is no requirement for any company or state to participate in the program.

In regulated states, state PUCs protect retail customers of a utility by assuring that reliable service is available at reasonable rates. In balancing ratepayer and investor

¹⁹ See Jeremy David and Howard Herzog, "The Cost of Carbon Capture," read at Fifth International Conference on Greenhouse Gas Control Technologies, Cairns, Australia (August 13-16, 2000).

²⁰ See Statement of Dan L. Crippen, Director, Congressional Budget Office, Federal Loan Guarantees for Rural Television Service, before the Subcommittee on Telecommunications, Trade, and Consumer Protection Committee on Commerce, U.S. House of Representatives, p. 3 (March 16, 2000).

interests, state PUCs employ a variety of review procedures and cost recovery mechanisms, including, in some states, review and recovery of costs during construction and cost recovery through adjustment clauses. In deregulated states, state PUCs are implementing retail competition, although often a variety of cost recovery mechanisms (e.g., for transition costs, stranded asset costs, and public benefit programs) remain in place. As discussed above, for a state to participate in a 3Party Covenant, the state PUC must adopt certain review procedures and cost recovery mechanisms, which are similar to those already used in some regulated and deregulated states.

The strongest reason for state PUC participation is that IGCC base-loaded plants produce reliable and stably priced power at costs that are competitive with PC or NGCC alternatives and that the lower costs are passed on to retail customers. In addition, the state PUC's participation will help to deploy an environmentally superior technology with potential to produce hydrogen and to sequester CO₂. Further, the state PUC's participation will promote economic development in the state through construction and, in some states, coal mining jobs.

State PUCs are aware that environmental advocates are mounting strong opposition to any new or repowered PC plants. Environmental Defense and local environmental groups have intervened in various state proceedings to request regulatory findings that favor IGCC over PC plants. The issue of IGCC vs. PC is already being actively litigated in regulatory proceedings across the country whenever a PC plant is proposed. A program of promoting commercial development of IGCC, with coal as the principal fuel, will go a long way towards removing the stigma of coal as a "dirty" fuel.

Historic Precedent

The United States government has a long history of stimulating and steering energy production and development through: direct investment, direct loan, loan guarantees, tax credits, risk sharing, and research and development funding. For example, over the past 14 years, DOE's Clean Coal Technology Program has invested \$5 billion in research, development and demonstration of advanced scrubbers, selective catalytic reduction controls, coal cleaning techniques, and particulate and mercury controls. The DOE Clean Coal Technology budget is \$100 million annually, and in February 2003, President Bush committed \$1 billion to Future Gen, a commercial IGCC project with CO₂ sequestration and hydrogen production. The energy bill under consideration in Congress contains billions of dollars of energy loan guarantees, technology grants and tax credits and \$20 billion of loan guarantees to build the Trans-Alaskan Natural Gas Pipeline.²¹

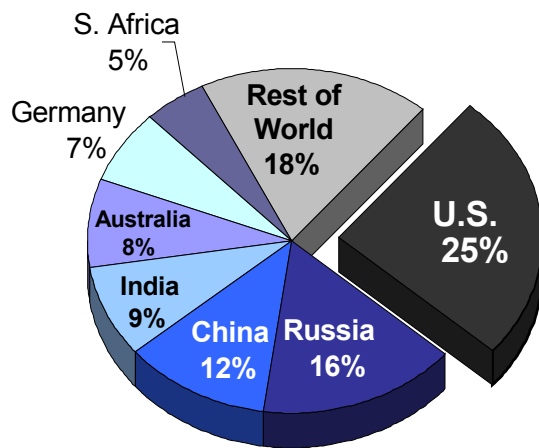
²¹ After enactment of any energy bill, the authors will examine the various IGCC incentives that may be available and consider how to incorporate them into this proposal.

Conclusion

Even though IGCC coal plants currently cost more to construct than PC plants, the 3Party Covenant provides an assured supply of financing on favorable terms that lower energy production costs of IGCC to below PC. The 3Party Covenant program also offers the opportunity to bring together diverse interests to support construction of a fleet of IGCC plants before the end of this decade: coal producers, utility and independent power producers, petrochemical and other natural gas dependent industries, environmental and consumer advocates, and state and federal energy, utility, and environmental agencies. The ability to secure broad support for IGCC plants, especially from environmental advocates that vigorously oppose any PC development, significantly increases the chances of successful development. Such development will begin to resolve the seemingly intractable tension between coal-based electricity supply and sustainable environmental protection.

Figure 1. U.S. Share of World Coal Reserves and Location of U.S. Coal Deposits

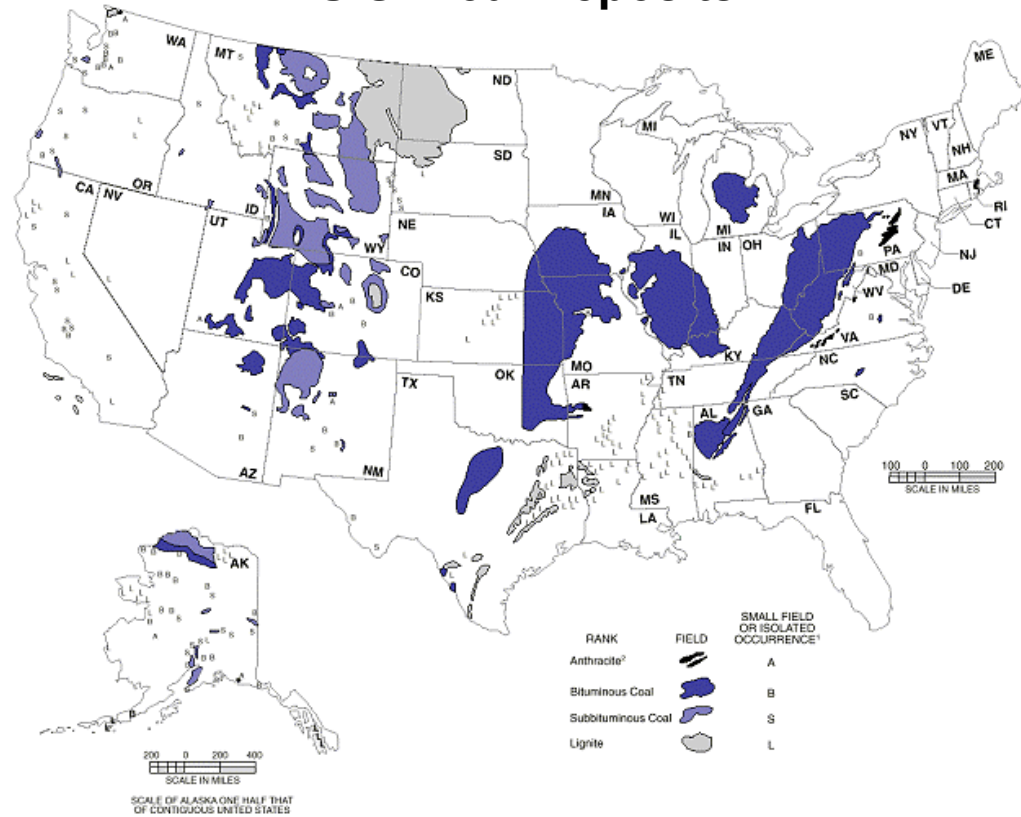
World Coal Reserves



1,083 billion tons

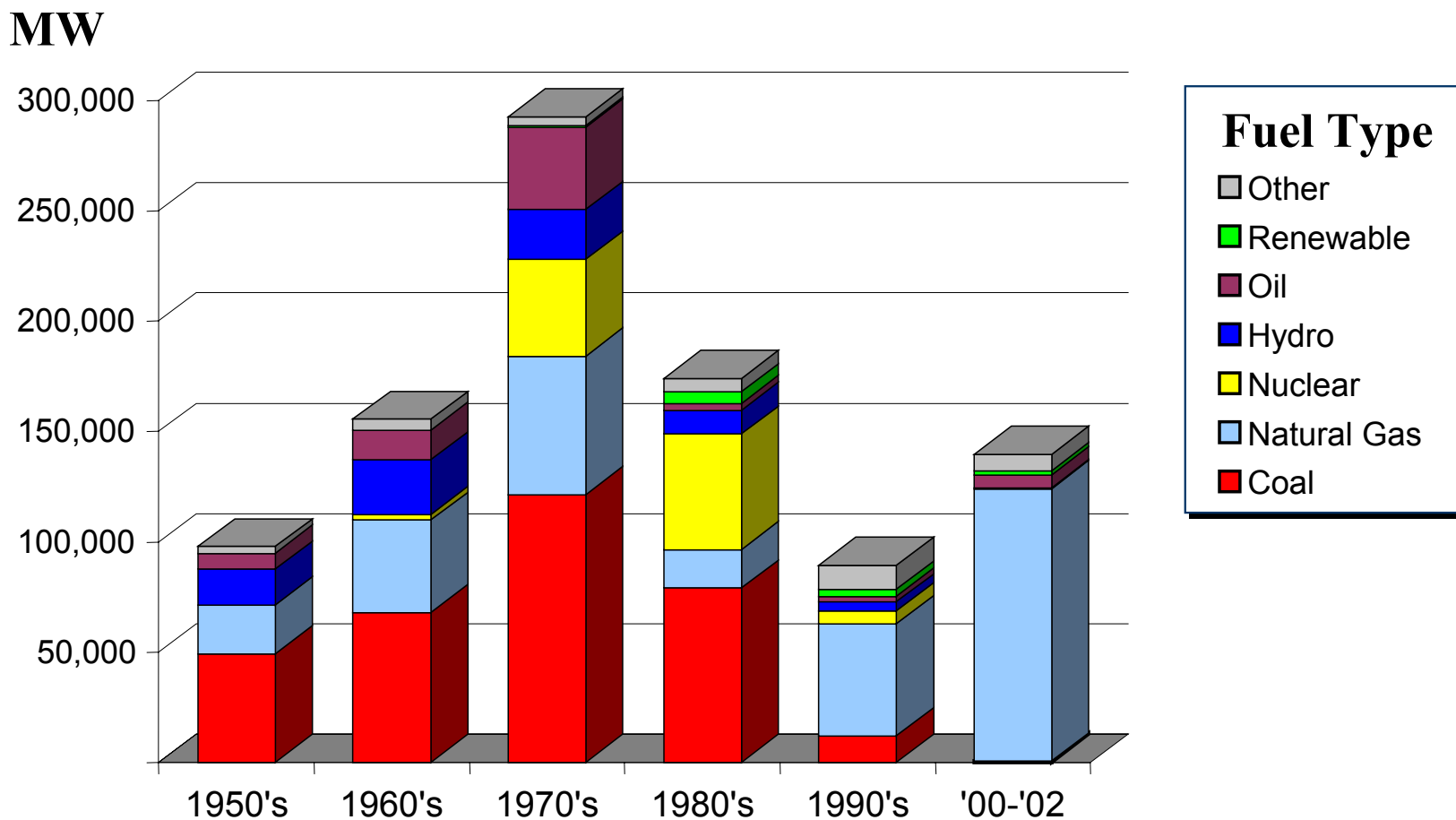
Source: EIA International Energy Annual 2001.

U.S. Coal Deposits

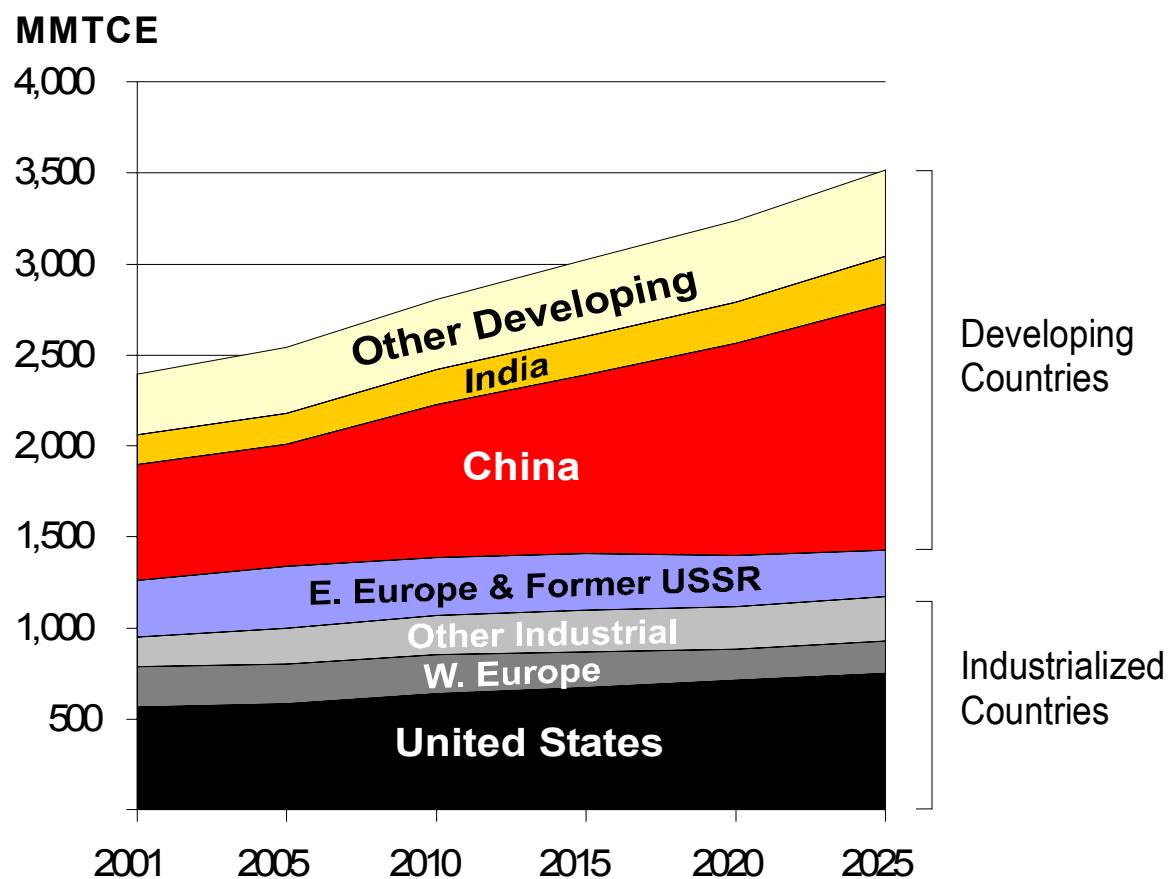


Source: EIA; <http://www.eia.doe.gov/cneaf/coal/reserves/chapter1.html#chapter1a.html>

Figure 2. U.S. Electric Generation Capacity Additions by On-line Date



Source: Form EIA 860 "Annual Electric Generator Report," 2001.

Figure 3. Projected World-wide CO₂ Emissions

Source: EIA, International Energy Outlook 2003, Table A-10, p.191.

Figure 4. Economic Impact of 3Party Covenant

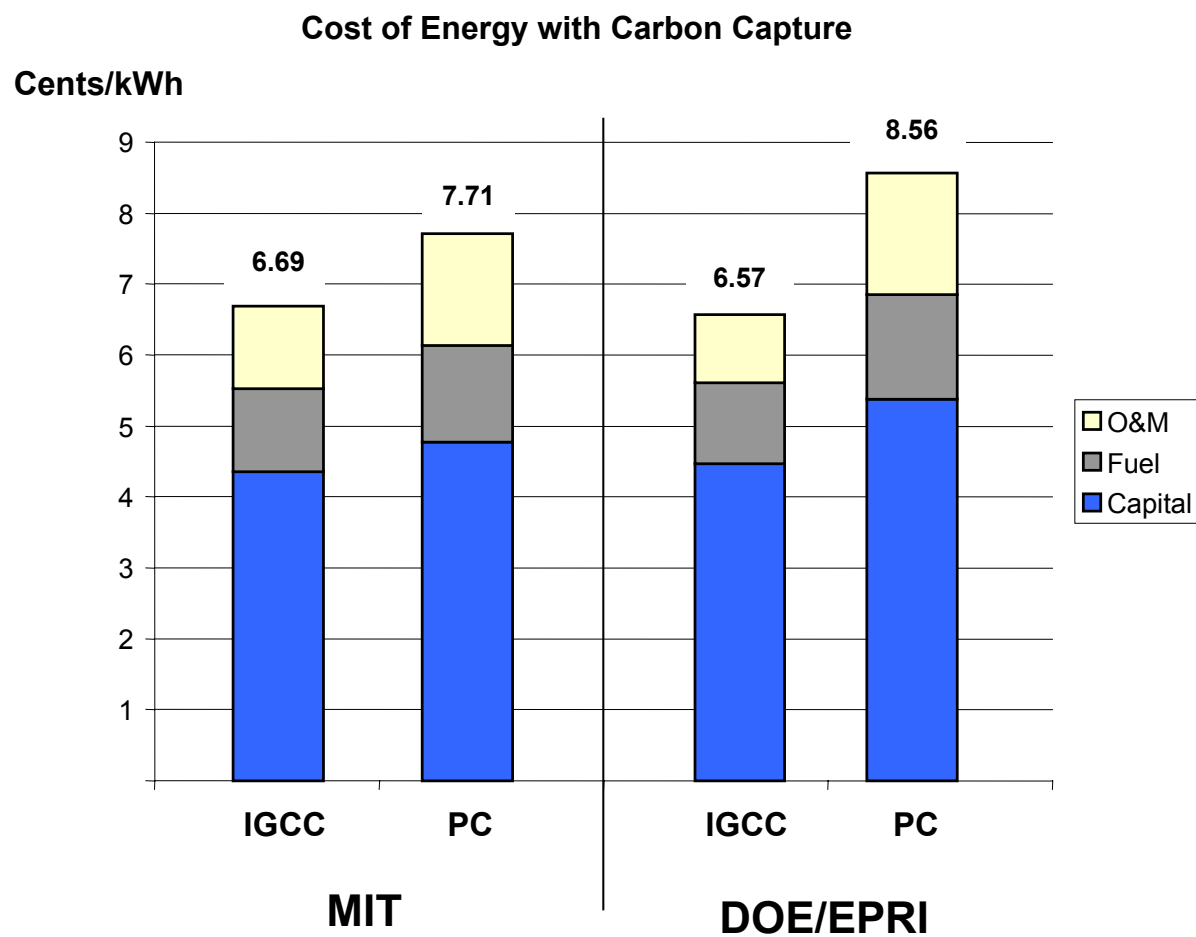
	Deregulated Merchant Plants			Traditional Regulated Utility Financed Plants			3-Party Covenant with Federal Loan Guarantee
	NGCC	Super Critical PC	Dual-train IGCC with extra gasifier	NGCC	Super Critical PC	Dual-train IGCC with extra gasifier	Dual-train IGCC with extra gasifier
Design and Construction							
Plant Size (MW)	500	600	600	500	600	600	600
Total Plant Cost--EPC (\$/kW)	\$510	\$1,150	\$1,400	\$510	\$1,150	\$1,400	\$1,400
Total Plant Investment -- EPC + AFUDC (\$/kW)	\$536	\$1,265	\$1,540	\$536	\$1,265	\$1,540	\$1,400
CWIP in Rate base (% of AFDC)	0%	0%	0%	0%	0%	0%	100%
Operation							
Fuel cost (\$/mmBtu)	\$4.50	\$1.24	\$1.24	\$4.50	\$1.24	\$1.24	\$1.24
Plant Heat Rate (Btu/kWh HHV)	6,800	8,600	8,600	6,800	8,600	8,600	8,600
Plant Availability (%)	90%	90%	90%	90%	90%	90%	90%
Plant Capacity Factor (%)	50%	85%	85%	50%	85%	85%	85%
Annual Generation (MWh)	2,190,000	4,467,600	4,467,600	2,190,000	4,467,600	4,467,600	4,467,600
Financing							
Percentage Debt				55%	55%	55%	80%
Debt Interest Rate				6.5%	6.5%	6.5%	5.5%
Percent Equity				45.0%	45.0%	45.0%	20.0%
After tax Equity Return				11.5%	11.5%	11.5%	11.5%
Federal Tax rate				34.0%	34.0%	34.0%	34.0%
State Tax rate				4.2%	4.2%	4.2%	4.2%
Pre-tax Common Equity Return				18.6%	18.6%	18.6%	18.6%
Pre-tax Weighted Avg. Cost of Capital				11.9%	11.9%	11.9%	8.1%
Levelized Carrying Charge (% of capital per year)*				15.1%	15.1%	15.1%	9.8%
Hurdle Rate	15.0%	15.0%	15.0%				
Estimated Cost of Energy							
O&M (cent/kWh)	0.25	0.75	0.88	0.25	0.75	0.88	0.88
Fuel (cent/kWh)	3.06	1.07	1.07	3.06	1.07	1.07	1.07
Levelized Carrying Charge for Capital (cent/kWh)	1.83	2.55	3.10	1.85	2.57	3.13	1.83
Cost of Energy (cent/kWh)	5.14	4.36	5.05	5.16	4.39	5.08	3.78

* Calculated with a DOE contractor model based on EPRI methodology utilizing straight-line depreciation and assuming a 30 year life.

Figure 5. Summary of Cost Data for IGCC and PC Power Plants

	IGCC			PC		
	Capital (\$/kW)	Heat Rate (Btu/kWh)	O&M (cent/kwh)	Capital (\$/kW)	Heat Rate (Btu/kWh)	O&M (cent/kwh)
Estimates from Published Studies						
EIA Annual Energy Outlook (2003 Assumptions)	1,367	8,000		1,154	9,000	
NETL/EPRI Parsons Case 9A (E-Gas w/ F turbine) (2002)	1,208	8,609	0.64			
NETL/EPRI Parsons Case 3B (E-Gas w/ H turbine) (2002)	1,263	7,915	0.80			
NETL/EPRI Parsons Case 7C SCPC (2002)				1,143	8,421	0.99
NETL/EPRI Parsons Case 7D USCPC (2002)				1,161	7,984	0.96
Herzog Year 2000 Plant (2000)	1,401	8,506	1.16	1,150	8,713	0.74
Herzog Year 2012 Plant (2000)	1,145	7,513	0.84	1,095	8,465	0.61
IEA (Stork Engineering, 1999)	1,471	7,369	0.96	1,022	7,482	0.72
SFA Pacific (Simbeck, 1998)	1,100	7,210	0.79	1,300	7,680	0.79
EPRI Shell-HR Illinois # 6 coal (1998)	1,340	8,225				
EPRI Shell-HR Pittsburgh # 8 coal (1998)	1,274	7,881				
EPRI Texaco-HR Illinois # 6 coal (1998)	1,314	8,214				
EPRI Texaco-HR Pittsburgh # 8 coal (1998)	1,247	8,113				
EPRI Texaco-Q Illinois # 6 coal (1998)	1,201	9,622				
EPRI Texaco-Q Pittsburgh # 8 coal (1998)	1,148	9,316				
EPRI Global-HR Illinois # 6 coal (1998)	1,225	8,248				
EPRI Global-HR Pittsburgh # 8 coal (1998)	1,171	8,066				
Argonne National Lab (Doctor et al) (1997)	1,332	8,938	0.93			
Actual Experience at Demonstration Plants						
Wabash Generating Station	1,680	8,595				
Polk Power Station	1,790	9,643				
Regulatory Filings						
SFA Pacific BACT Analysis of Prairie State (Texaco 4 gasifiers)				1,150	9,521	0.42
SFA Pacific BACT Analysis of Prairie State (Texaco 4 gasifiers)	1,795	10,622	0.96			
SFA Pacific BACT Analysis of Prairie State (Texaco 10 gasifiers)	1,516	10,576	0.81			
SFA Pacific BACT Analysis of Prairie State (Global 4 gasifiers)	1,876	9,492	1.00			
SFA Pacific BACT Analysis of Prairie State (Global 10 gasifiers)	1,584	9,451	0.84			
WEPCO Elm Road Proposal	1,739			1,415		
Average of all data points	1,399	8,642	0.88	1,177	8,408	0.75
Project Base Case Cost Assumptions						
	1,400	8,600	0.88	1,150	8,600	0.75

Figure 6. Cost of Energy Comparison between IGCC and PC Assuming Carbon Capture



Sources: MIT: Jeremy David and Howard Herzog, The Cost of Carbon Capture, Paper read at Fifth International Conference on Greenhouse Gas Control Technologies, August 13-16, Cairns, Australia. DOE/EPRI: Evaluation of Innovative Fossil Fuel Power Plants with CO₂ Removal, December 2000, IGCC case 3A; PC Case 7A.