AN ANALYSIS OF THE INSTITUTIONAL CHALLENGES TO COMMERCIALIZATION AND DEPLOYMENT OF IGCC TECHNOLOGY IN THE U.S. ELECTRIC INDUSTRY:

Recommended Policy, Regulatory, Executive and Legislative Initiatives

Final Report

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Executive Summary

This Report identifies and prioritizes the institutional (i.e., non-technical) challenges to the rapid commercialization and deployment of coal gasification technologies in the U.S. electric power sector and provides recommendations for overcoming them. It focuses on Integrated Gasification Combined Cycle (IGCC) technology, the most successful method of producing electric power utilizing coal gasification. The Report recommends a number of regulatory, legislative, executive and policy initiatives, at both the federal and state levels, for achieving those objectives. Readers who want to move directly to the recommendations may skip to Section 4.

Section 1. Overview of IGCC Technology and History

The first section of this Report provides a non-technical overview of coal gasification, particularly IGCC technology, and its applicability to the U.S. power industry. Increased utilization of coal gasification power plants offers affordable and high-efficiency electricity production from an abundant, readily available source of energy, with superior environmental performance compared to other coal-based technologies. Deployment of these plants can reduce America's growing dependence on natural gas-fueled electricity generation, thereby freeing up natural gas for essential uses such as industrial processes and residential heating. Further, in addition to electricity, gasification-based power plants can produce a wide range of products, including transportation fuels, chemicals, hydrogen, fertilizers, and steam, while utilizing low-cost, widely available feedstocks such as petcoke, instead of natural gas and oil.

The U.S. Department of Energy (DOE) is currently conducting extensive research on technological improvements that will increase the efficiency and cost-effectiveness of commercial-sized IGCC power plants, making them fully competitive with other power generation technologies. The research is focused on: (1) more efficient separation of oxygen from air; (2) improved systems for cleaning syngas; and (3) improved gas turbine designs. These efforts are expected to yield commercially viable technologies within the next few years that can be deployed in a new generation of IGCC power plants.

Section 2. Benefits of IGCC Deployment

Accelerated IGCC deployment in the U.S. power sector will provide critical benefits in four key areas: environmental; technology advancement; economic; and energy and national security. Each is discussed below.

Environmental Benefits

IGCC plants would dramatically reduce emissions of sulfur dioxide, nitrogen oxides, mercury, particulates, and carbon dioxide compared to levels produced by conventional coal-fueled plants. In fact, sulfur dioxide and nitrogen oxides can be reduced substantially below the Clean Air Act's new source performance standard ("NSPS") requirements for coal-fueled facilities. Carbon dioxide emissions can also be controlled more effectively with IGCC technology than with other coal-fueled or natural gas fueled technologies. Capture of carbon dioxide emissions reduces the power output of an IGCC power plant by only 14%, whereas the decrease is 21% for natural gas-fueled plants and 28% for conventional coal-fueled plants when comparing similar percentage levels of carbon dioxide reduction.

Technology Benefits

IGCC technology contributes to the development of new energy technology in several critical areas. It will facilitate carbon dioxide sequestration, since IGCC technology can almost completely separate carbon dioxide from the bulk gaseous discharge stream. In addition, IGCC facilities can be used to co-produce liquid fuels and commodity chemicals. Further, since coal gasification can be tailored to produce hydrogen, IGCC power plants can play an integral role in establishing the "hydrogen economy."

Economic Benefits

IGCC technology would provide an opportunity to cost-effectively repower older, conventional coal plants, and address a number of environmental problems going forward. This would involve a substantially lower cost than piecemeal, incremental retrofits. The use of IGCC technology would also reduce reliance on natural gas for electricity generation, and free up natural gas for essential uses such as industrial processes and residential heating. The rapid commercialization and deployment of IGCC power plant technology in the U.S. could also lead to valuable foreign trade opportunities. This would bolster U.S. exports and contribute to growth in domestic employment. The potential for IGCC power plant exports is vast given the rapid growth in electricity demand and abundant coal reserves in countries such as China.

National Security Benefits

The timely commercialization and deployment of IGCC power plants would be very valuable in decreasing reliance on imported fuels from unstable regions that are hostile to U.S. interests. Using coal rather than natural gas or oil to generate electricity can be done without fear of shortages or international disruptions. Additionally, IGCC power plants can produce diesel fuels that could displace a significant amount of domestic transportation fuel consumption and thereby reduce oil imports. A further national security benefit is that the coal supply chain is less vulnerable to sabotage than oil or natural gas infrastructures.

Section 3. Identification and Ranking of Challenges to IGCC Deployment

A survey of industry experts and institutional stakeholders was conducted to identify and prioritize the most significant institutional challenges to the rapid commercialization and deployment of IGCC power plants. An initial list of institutional challenges was developed based on a review of the literature and informal discussions with experts and stakeholders. The list was completed and the items were organized into six categories, including: (1) legal/regulatory; (2) environmental; (3) financial; (4) economic; (5) cultural; and (6) technological.

The analysis of the survey data focused on identifying the most significant challenges as ranked by the respondents. The four highest-ranking items--"Top-Tier Challenges"--included three financial concerns and one technological concern:

- Higher capital costs than other power plants
- Doubts about plant viability without subsidies
- Increased risks associated with up-front development costs
- Low plant availability in the early stages of operation.

Respondents identified 25 Second-Tier challenges. Those items included concerns about:

- The uncertainty of environmental regulations
- Past technological failures of IGCC
- Availability of project finance
- Lack of overall performance guarantees
- Uncertainty of tax credits.

The survey results served as key inputs in framing the Report's recommendations.

Section 4. Recommendations

The recommendations presented in this Report were developed on the basis of the survey results as well as suggestions by stakeholders and experts. The recommendations are organized into six key areas: (1) Siting and Permitting; (2) Project Financing and Plant Availability; (3) Co-production/National Security; (4) Strategies for Meeting Environmental Standards; (5) Relative Cost of IGCC Power Plants and Natural Gas Combustion Turbines; and (6) Federal and State Government Roles.

Siting and Permitting

--The federal and state governments could initiate an expedited process to develop a single set of standards specifically for siting and permitting IGCC power plants including co-production processes.

--The states could develop Memoranda of Understanding specifying compatible regional standards to address air shed issues associated with IGCC permitting.

The licensing of IGCC power plants is far more complex than the process for permitting conventional coal or natural gas-fueled generation facilities. Currently, IGCC plants are subject to multiple federal and state environmental rules, and may be licensed, at a minimum, as electric generation units, syngas facilities, and co-production plants. This is a major challenge to IGCC deployment. The White House Task Force on Energy Project Streamlining could establish a multi-jurisdictional group to develop uniform licensing standards for IGCC plants and has indicated an interest in doing so.

Project Capital and Plant Availability

--A fund could be established to provide for the sharing of possible IGCC capital cost overruns.

Uncertainty regarding capital costs is a Top-Tier challenge to IGCC deployment. If capital costs exceeded a pre-determined target, there would be a sharing of the overruns between the developer and the federal government. This sharing mechanism could partially protect developers against cost overruns without unduly weakening their incentive to hold down project costs.

--An IGCC Availability Assurance Program could be established.

Concern about possible limited availability of IGCC facilities in their early stages of operation is also a Top-Tier challenge to IGCC deployment. The IGCC Availability Assurance Program, modeled after similar programs the federal government has established in other areas, could address those concerns. It would provide funding to partially defray the cost of possible extended outages in the first few years after a plant is put into operation.

Co-Production/National Security

--A study could be initiated to analyze the ability of IGCC power plants to operate on an economic dispatch basis to produce transportation fuels as well as electricity.

An IGCC facility can produce both electricity and transportation fuels. The value of the plant can be optimized by turning out each product when its price is highest--i.e., producing electricity during the day when demand--and prices--are high, and producing transportation fuels when electricity demand and wholesale electric prices are low. Moreover, the production of transportation fuels from such a facility would provide significant national security benefits.

Strategies for Meeting Environmental Standards

--Probabilistic projections of future emissions policies could be developed.

--A study could be undertaken to examine the economics of addressing potential emissions reduction requirements by repowering existing plants rather than pursuing a piecemeal approach to treating individual emissions.

--Strong accounting standards could be developed to recognize the value of future emissions reduction credits that will accrue to IGCC projects.

--The forward value of nitrogen oxide and sulfur oxide emissions allowances could be monetized through the creation of forward markets and valued through accounting standards that allow recognition of these assets by the Securities and Exchange Commission and state PUCs.

--The forward value of obviating incremental mercury and particulate emissions control expenditures could be monetized through the creation of forward markets.

--A study could be undertaken to assess the potential value of water quality credits related to the use of animal waste as a feedstock for IGCC power plants.

--A study, similar to the one presented in this Report, could be undertaken to address institutional challenges to commercialization and deployment of carbon dioxide sequestration technologies.

The deployment of IGCC technology is hindered by uncertainty regarding future regulations, the piecemeal approach of the electric industry and regulators to meeting future environmental standards, and the absence of efficient markets in which the forward value of emissions reductions can be monetized. As result, the value of emissions reductions cannot be recognized as an offset to the capital costs of IGCC technology--which survey respondents identified as a critical challenge to IGCC deployment. Consequently, determinations regarding the choice of technology for new generating facilities and for repowering existing plants cannot be made on a sound economic basis.

In view of these considerations, efforts could be made to develop comprehensive plans for meeting existing and anticipated emissions reduction requirements. Appropriate measures could be implemented to monetize the value of future emissions allowances, including accounting standards which reflect that value.

Cost of IGCC Power Plants Relative to the Cost of Natural Gas Combustion Turbines

--Measures could be developed to facilitate deployment of IGCC power plants and reduce undue reliance on natural gas combustion turbines, thereby decreasing pressure on limited natural gas supplies and freeing up natural gas for essential uses such as industrial processes and residential heating.

--Transmission Service Providers (TSPs), Independent System Operators (ISOs) and Regional Transmission Organizations ("RTOs") could be required to establish target portfolio standards for IGCC-produced power.

--TSPs, ISOs and RTOs could be required to provide modest credits financed through uplift charges for electricity produced by IGCC power plants in their early stages of operation.

--A study using the National Energy Modeling System (NEMS) could be undertaken to assess the impact of expanded IGCC deployment on natural gas prices.

The survey of stakeholders indicated that the most significant challenge to the deployment of IGCC power plants is their higher capital costs relative to natural gas combustion turbines ("NGCTs"), which have accounted for most new generating facilities in recent years. However, the pricing of electricity from NGCTs and IGCC power plants does not adequately reflect several critical considerations including the importance of using natural gas in industrial processes and residential heating, the recent run-up in natural gas prices resulting from increased pressure on supplies, the accelerated depletion of the nation's limited reserves of natural gas, and the need for increased reliance on gas supplies from unstable areas of the world as domestic supplies are used up. Accordingly, new policies should be developed to address this situation.

Recommended Federal and State Actions

--The EPA could initiate negotiations with owners of existing conventional coal-fueled power plants to explore means of monetizing the benefits of future emissions reductions in order to develop a comprehensive policy for lowering emissions rather than a piecemeal, incremental approach.

The analysis developed in this Report demonstrates that meeting requirements for reduced emissions of sulfur oxides, nitrogen oxides and mercury by using IGCC to repower conventional coal-fueled generating plants would be far less costly than meeting each of the requirements separately pursuant to a piecemeal approach. Accordingly, the EPA could initiate negotiations with coal plant owners to develop a comprehensive approach for meeting existing and anticipated emissions reduction requirements based on repowering with IGCC technology. These discussions could consider mechanisms for monetizing future reductions of nitrogen oxides and sulfur dioxide, as well as other pollutants such as mercury and particulates that are likely to be regulated in the future. Such negotiations could result in long-term settlements and the repowering of existing coal-fueled plants with IGCC technology.

--A strong federal greenhouse gas (GHG) emissions reduction registry, with effective measurement and verification standards, could be established to facilitate private, voluntary bilateral transactions. The federal GHG registry could be made compatible

with the GHG emissions reduction registries that are being developed by other nations, and with emissions credit markets that are being created in the U.S. and abroad.

--States and/or regions, working through NARUC, could establish uniform GHG registries that are compatible with the federal registry as well those created abroad.

--States could develop a set of tools to be used in the regulatory process to take into account reductions in GHG in existing and developing registries.

--A review could be initiated to facilitate the voluntary trade of U.S.-based carbon dioxide emission reductions credits in bilateral transactions and private exchanges, and in public markets being created by the European Union and Pacific Rim nations. The Department of State could coordinate this effort.

Although there has been some limited trading of GHG emissions reduction credits, there is no U.S. standard for verifying such transactions and no systematic, comprehensive procedure for recording them. A strong federal GHG registry, with effective measurement and verification standards, could be created to facilitate voluntary GHG emissions reduction. It could be supplemented by state and/or regional registries that utilize the same standards. These registries could facilitate bilateral trading in GHG reductions and also allow entities to bank reduction credits for future use. This could provide an important means of financing IGCC projects, particularly repowering of older coal-fueled plants that could substantially reduce GHGs.

The federal and state GHG registries could be made compatible with the GHG registries that are being developed by other nations, and with trading markets that are being created in the U.S. and abroad. Ideally, this could enable entities to use reductions recorded in U.S. registries to meet GHG emissions reduction requirements elsewhere in the world.

It would also be useful to develop a set of tools that regulators could use to take GHG reductions in existing and developing registries into account in the regulatory process. For instance, state regulators could consider granting regulatory assets in exchange for GHG credits in acceptable registries.

--A single, dedicated information source and database could be established to assist in the siting and permitting of IGCC power plants, and to assist in the process of equipment and technology procurement.

The White House Task Force on Energy Project Streamlining could take the lead in establishing this database and has indicated an interest in doing so. This could assist developers in acquiring the information and assets needed to foster rapid commercialization and deployment of IGCC technology in the U.S. power sector.

--A single staff of highly qualified experts could be established by DOE to play a significant role in the siting and permitting of IGCC power plants in the U.S., and serve as ombudsmen for developers of IGCC power projects.

A specialized team of experts could assist in the siting and permitting processes for IGCC power plants, and in bringing new technological advances into the process. Such an expert team would cost the federal government very little, but could significantly assist in the process and improve prospects for IGCC deployment. In addition, this staff could intervene in siting and permitting proceedings to assure that the benefits of employing IGCC rather than conventional, combustion-based technologies are fully considered in technology choice determinations.

--An educational team could be established by DOE to inform and educate the financial community, state regulators, utility management, and the power plant development industry about the proven benefits of the IGCC technology and its commercial viability, and to make a business case for IGCC power plant financing.

The project finance community is familiar with financing natural gas-fueled plants, but has virtually no experience with IGCC facilities. A targeted effort to assist the financial community in understanding the issues associated with IGCC deployment would be welcomed and could likely position IGCC as one of the preferred technologies. Such information could also be provided to state regulators and the power plant development industry.

--DOE could establish a university center for the training and qualification of personnel capable of participating in the design, construction and operation of IGCC power plants.

The workforce at existing conventional coal-fueled power plants is aging, and there are few individuals who are familiar with IGCC power plants. A program for training and qualifying personnel capable of designing, building and operating IGCC power plants is needed to rapidly commercialize and deploy this technology, and realize its benefits.

--A business case for the benefits to the U.S. of exporting IGCC technology, equipment and construction services to other nations could be developed.

The Export-Import Bank, the Department of Treasury or another appropriate entity could evaluate the economic implications of the exporting IGCC technology, construction services, and equipment.

--Lastly, a program could be established and funded to assist in the implementation of these recommendations after the energy policy community reviews them.

The implementation of these recommendations will require resources and dedicated staff if they are to be successfully realized. An implementation plan could be developed to ensure that adequate resources and funding are available.

INTRODUCTION

The purpose of this Report is to outline recommendations for policy and regulatory initiatives on both the federal and state levels to facilitate the commercialization and deployment of coal gasification technologies in the U.S. power industry. Coal gasification technology allows electric power to be generated from a range of coal grades and petroleum products without significant solid, liquid or gaseous pollutants or wastes compared to other coal-based generation, while producing a number of byproducts that can be utilized in a variety of applications. Further, with the substantial supply of coal in the U.S.--at least 275 years at today's consumption levels[1]--and the long-term price stability of the coal market,[2] utilizing this technology for electric generation will provide critical economic, environmental, social and national security benefits.

The U.S. government has invested hundreds of millions of dollars in research and development on, and demonstration of, coal gasification technology. As a result of those efforts, the application of coal gasification technology to electric power generation is no longer speculative. Production of electric power from coal gasification has been successfully demonstrated in a number of significant operating projects. New policy initiatives must be developed and implemented now to ensure that the substantial benefits of this technology are realized. Given the clear advantages of using coal to generate electric power at a very low level of environmental impact and at stable low prices, the rapid commercialization and deployment of coal gasification in the U.S. electric power sector should be a critical policy objective of federal and state governments.

This Report has been prepared for policy makers, regulators, legislators, other public officials, the financial community, electric utility management, and the general public. It is intended to provide essential information without being overly technical.[3] Section 1 presents a general overview of coal gasification that serves as a conceptual framework for subsequent parts of the Report. Section 2 discusses the benefits of using coal gasification to generate electricity. Section 3 reviews the results of a survey that identified and ranked the challenges to expanded utilization of coal gasification. And Section 4 presents recommendations for overcoming those challenges.

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[1]Testimony of Mary Hutzler, Director EIA, before House Subcommittee on Energy and Air Quality, March 14, 2001. Approximately 275 billion tons of coal has been judged to be recoverable and approximately 1 billion tons of coal are mined and consumed annually in the U.S. About 90% of that production is used to generate electric power. According to the Energy Information Agency, coal accounts for approximately 52% of electricity produced in the U.S.

[2] The cost of coal is projected to decrease over the next two decades due to improvements in mining efficiency. EIA "*Annual Energy Outlook 2003.*

[3] Numerous technical publications on coal gasification are available on the web site of the National Energy Technology Laboratory ("NETL")--http://www.netl.doe.gov.

SECTION 1.
OVERVIEW OF IGCC TECHNOLOGY AND HISTORY

This Section provides a general description of coal gasification technology, a brief history of coal gasification, a discussion of existing coal gasification electric power plants, a summary of current research, and a review of applicable energy tax policy. As shown in this Report, coal gasification has been used successfully on a commercial scale and can be more widely deployed in the U.S. to achieve major benefits in the areas of environmental protection, technology advancement, economic growth, and national security.

1.1 IGCC Technology

Coal gasification is the process of converting coal into a gas--"syngas"--that can be used for a number of purposes, including electric power generation. The most successful method of producing electric power with coal gasification is the Integrated Gasification Combined Cycle ("IGCC") process. As discussed below, two commercial size coal-fueled IGCC power plants in the U.S. are already producing low cost power and are the among the cleanest coal-fueled plants in the world--the 250 MW[4] Polk facility in Florida and the 262 MW Wabash River plant in Indiana. In addition, there are two other significant IGCC generating plants outside the U.S. that are producing similar results. Further, there are a number of other coal gasification facilities that produce a wide range of gaseous and chemical products, including the Great Plains Synfuels Plant in North Dakota and the Eastman Chemical plant in Tennessee.

As illustrated in Figure 1.1, the first part of the IGCC process involves the chemical conversion of coal into syngas, a mixture of hydrogen and carbon monoxide. This reaction is carried out in a "gasifier," using very high temperature and only a limited amount of oxygen. When the syngas leaves the gasifier, it must be cleaned of any particulates (i.e., small solids) and other contaminants such as sulfur, ammonia and chlorides, so that it can be used to generate electricity in a manner similar to the process employed in natural gas-fired units.[5] Once the syngas is cleaned, it is fed into a gas turbine, which turns an electric generator to produce electric power.[6] In addition, the hot exhaust gas from that process flows into a steam generator and produces steam, which then turns a steam turbine that powers a second electric generator.

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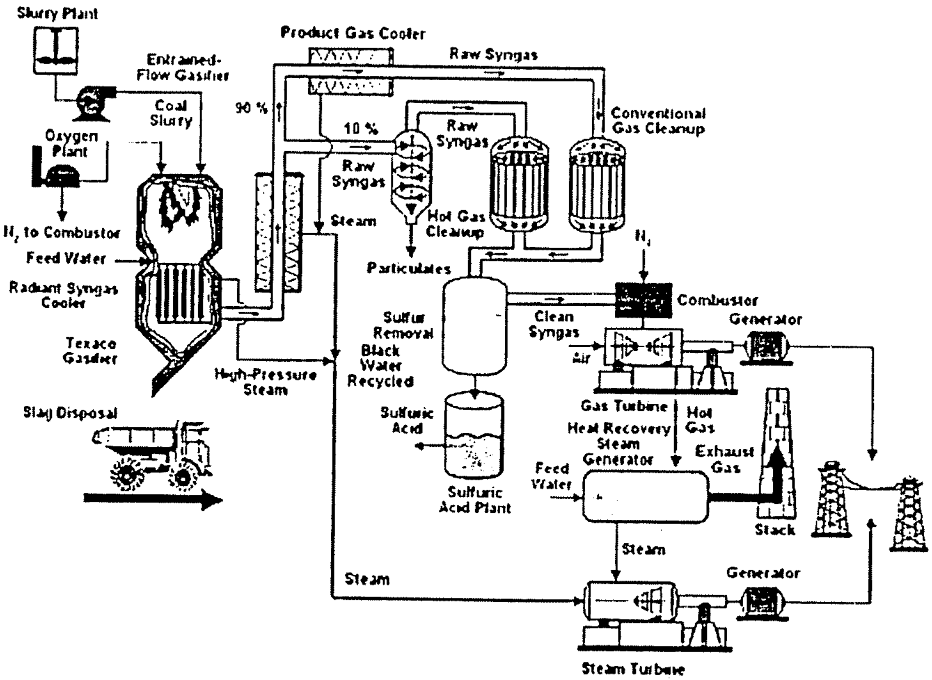
[4] A megawatt (MW) is 1,000 kilowatts of electricity. To put this in perspective, ten 100-watt light bulbs consume one kilowatt of electricity if all are on at once. A typical home uses about 1.5 kilowatts of electricity at its peak consumption. A MW of generating capacity can provide enough power for about 700 average size homes.

[5] Particulates and other contaminants will damage a gas turbine and therefore must be removed.

[6] Nitrogen and/or steam are injected into the gas turbine along with the syngas to, among other objectives, significantly reduce the production of nitrogen oxide emissions.

Figure 1.1—IGCC Process[7]



These processes are referred to as "combined cycle" ("CC") generation. It is the technology employed in most new, large natural gas-fired generating plants. The use of combined cycle technology, together with coal gasification, significantly improves the efficiency of utilizing coal for electric generation while emitting a very low level of pollutants.

There are several variations of the basic IGCC power plant design that differ mainly in the methods used to remove pollutants. Nevertheless, all of those designs result in very low emissions and commercially saleable byproducts. Moreover, because the byproducts have commercial value, the waste disposal costs of IGCC plants may actually be negative--i.e., depending on the markets for these byproducts, they may produce net income for the plants. (Not all of the byproduct markets have fully developed, so it is difficult to accurately quantify these benefits at this time.) In contrast, a conventional coal-fueled power plant[8] produces waste streams that impose substantial waste disposal costs on its owner.[9]

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[7] This schematic of the Polk IGCC Power plant was prepared by the National Energy Technology Laboratory. This schematic represents the Chevron-Texaco technology.

[8] The term "conventional" as used in this Report refers to existing coal-fueled power plants. Approximately 90% of these units utilize "pulverized coal" furnaces, and are often referred to as "PC" plants. See Kilgroe, et al., *Control of Mercury Emissions from Coal-Fired Boilers: Interim Report*, US EPA, EPA-600/R-01-109, December 2001.

[9] According to the Gasification Technologies Council, a traditional 100 MW coal-fueled power plant must pay from $570,000 to $1,200,000 per year in disposal costs, whereas a 100 MW IGCC power plant would earn a profit of $440,000 per year from the sale of commercially useful byproducts and would experience minimal disposal costs. The byproducts from IGCC include ash (dry), slag (dry), carbon in ash (dry), elemental sulfur, $CaSO4$ (Anhydrite), water in $CaSO4 \cdot 2H_20$, CaO (Dry), water in $Ca(OH)_2$, and inerts from limestone. Further, after some chemical synthesis, several other saleable products can be produced. These include sulfuric acid; ammonium sulfate and anhydrous ammonia, which are agricultural fertilizers; dephenolized cresylic acid, which is used in the manufacture of pesticides and products such as wire enamel solvent; phenolic and epoxy resins and antioxidants; krypton and xenon gases, which are used for specialty lighting, such as high-intensity lighting and lasers, and for thermopane window insulation;

1.2 History of Coal Gasification

Gasification of coal to produce a useful gaseous fuel is now almost two centuries old. The first large-scale commercial application started in 1816 when gas from a coal gasifier was used to light residences, streets and businesses in Baltimore. Within a short time, entrepreneurs around the country began building small coal-to-gas plants and selling the syngas for lighting. By the mid-1800s, more than 400 gas plants were operating throughout the Northeast U.S. and in regions along the Mississippi River. The process was also used abroad. In the 1850s, much of London was illuminated by "town gas" produced from the gasification of coal. At the beginning of the 20th century, there were over 1,000 gas plants operating in the U.S. By 1920, coal gas served an estimated 46 million people in the U.S. in almost 5,000 communities. Annual coal gas production exceeded 326 billion cubic feet.[10] The use of coal gas declined rapidly by the 1930s as natural gas produced in Louisiana and Texas, and transported through pipelines to populated areas in the rest of the U.S., became available and supplies of electricity from conventional coal-fueled generators expanded.

Although the use of coal gas in the U.S. decreased in the 1930s and 1940s, Germany initiated an intensive research and development program on coal gasification prior to and during World War II. With limited access to oil and gas supplies, Germany developed processes for producing gasoline, diesel fuel and other liquid fuels from its abundant coal supplies. In particular, the Fischer-Tropsch (F-T) process was developed. This process, which is still employed today, uses a catalytic reaction process to produce longer hydrocarbons, called "F-T liquids" or "synfuels" from syngas.[11] For instance, diesel fuel could be produced in large quantities from coal converted at IGCC power plants. The ability to produce transportation fuels from coal--and thereby reduce dependence on imported oil--is an important national security benefit that can be derived from IGCC technology. The F-T process is discussed in greater detail later in this Section.

The energy crises of the 1970s dramatically heightened U.S. interest in the development of synfuels.[12] The federal government expanded conceptual and design work on synfuels production. In light of the nation's increased dependence on foreign oil and vulnerability to oil embargoes at that time, the question became not whether the government should promote the production of synfuels, but rather how quickly that should be done and in what manner. Two types of policy initiatives were implemented: (1) research and development and (2) financial assistance and support.

1.2.1 Research and Development

Legislation enacted in 1977 established a cabinet-level U.S. Department of Energy (DOE),[13] which incorporated the functions of the Energy Research and Development Administration.[14] Under the new DOE structure, primary responsibility for coal gasification research was conferred upon the Morgantown Energy Technology Center, now part of the U.S. DOE National

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and liquid nitrogen, which is used for food processing refrigeration, as an oil well additive and in chemical processes.

[10] Heritage Research Center Ltd, www.hertitageresearch.com/manufactured_gas.D.htm

[11] There are several proprietary variations of the F-T process that are in use at this time, and still others are being developed.

[12] Synfuels are generally defined as liquid fuels that are derived from syngas.

[13] The U.S. Department of Energy was established by the DOE Organization Act, Pub. L. No. 92–91 (1977), 42 U.S.C. §§ 7101, et seq. DOE is the primary manager of the federal government's energy functions.

[14] 42 U.S.C. § 7151 (a).

Energy Technology Laboratory (NETL). The Laboratory has a dual role: (1) providing the DOE with in-house research and development capabilities and (2) managing millions of dollars in research and development contracts carried out by universities, private industry, and other research institutions.

Research at NETL between 1978 and 1985 led to the development of an operational entrained gasifier, the key technology that has been used in subsequent demonstration projects and in the commercial size IGCC power plants that are currently in operation. Entrained technology enables the plant operator to inject coal directly into a gasifier, thereby providing an alternative to fluidized bed technology.[15]

1.2.2 Financial Support

In the late 1970s, Congress authorized loan guarantees for the development of alternative fuels including the production of syngas. This was done to encourage the private sector to participate in financing of these new fuel sources. Under that legislation, non-recourse financing provided by the federal government guaranteed recovery of 75% of investments in such projects. [16]

In one project, a consortium of energy companies obtained federally guaranteed loans to finance the construction of the $2.2 billion Great Plains Synfuels Plant. The facility was designed to produce synthetic natural gas which is mixed with conventional natural gas and sold to a local gas distribution company. It was not designed to produce electricity.[17] Operations began in 1984. However, the consortium abandoned the plant in 1985, defaulting on the $1.5 billion guaranteed loan. The DOE assumed ownership in 1986. In 1988, DOE sold the plant to Dakota Gasification Company, a wholly owned subsidiary of Basin Electric Power Cooperative. Since then, imaginative engineering solutions to pollution control and commercial necessity have resulted in sales of a growing number of commercially valuable byproducts from the plant, most notably ammonium sulfate--a fertilizer. The plant operates at a high availability rate. It also supplies 200 million standard cubic feet a day of carbon dioxide to an oil field near Weyburn, Saskatchewan, Canada, through a 205-mile pipeline. The carbon dioxide is used there for enhanced oil recovery.[18]

Further, in 1980, the U.S. Synthetic Fuels Corporation was established by the enactment of the Energy Security Act of 1980 to provide financial assistance to commercial-scale synthetic fuels projects.[19] The U.S. Synthetic Fuels Corporation provided financial commitments to five projects. One was the 120 MW Cool Water Coal Gasification Plant in the Mojave Desert, which began operation in 1984. This IGCC power plant demonstrated the technical feasibility of IGCC power generation. Another project was the 160 MW Dow Chemical Coal Gasification Plant in

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[15] A "fluidized bed" is like a fountain of air on which the coal "floats" and burns in a highly efficient manner. On the other hand, entrained gasifiers simply inject the coal and oxygen into the conversion chamber where coal is converted to syngas, adding to the efficiency of the IGCC process.

[16] With "non-recourse project financing," financial backing is based upon the ability to pay off the project's debt using its potential cash flow rather than relying upon the creditworthiness of the project sponsors. Under this approach, the assets of the facility, including the long-term revenue-producing contracts, become the collateral for the lenders. See generally Scott L Hoffman, *The Law and Business of International Project Finance*, pages 4-11 (1998).

[17] Brian Ricketts, *Carbon Dioxide Capture and Storage: Fact-Finding Mission to the USA and Canada*, UK COAL PLC, World Coal Institute, Ecoal Newsletter, December 2002.

[18] The carbon dioxide is injected into nearly depleted oil wells to push additional oil up to the surface. In this way, it is "sequestered" against release to the atmosphere.

[19] Title I of the Energy Security Act, Pub. L. No. 96–294, 94 Stat. 611, 633 (1980), 42 U.S.C. §§ 8702 et seq. The Corporation expired in 1986.

Plaquemine, Louisiana, which began operation in 1987 and was the largest IGCC power plant operating at that time.

In 1984, after oil prices had declined from their peak levels of the late 1970s, Congress enacted legislation that rescinded $9.5 billion of the $19 billion appropriated for support of synthetic fuels projects. The legislation also limited the use of the remaining funds to projects that produced fuel that would not cost significantly more than the projected market price of competing fuels.

After the 1984 reduction in appropriations, the U.S. Synthetic Fuels Corporation did not fund any new projects. Subsequently, in 1986, all support for the Corporation was terminated and existing subsidies were allowed to expire.

1.3 IGCC Demonstration Projects

NETL took on new responsibilities in 1986 under the Clean Coal Technology Program, a partnership program between the federal government and industry. Among other reasons for this program was the U.S.-Canada agreement to decrease cross-border acid rain. In addition, the purpose of the program was to realize the full potential of coal as a source of energy (both in the U.S. and abroad) by encouraging the development of highly efficient, environmentally sound, and economically competitive coal utilization technologies.[20] The program sought to introduce these technologies to the marketplace through demonstration projects on a scale large enough for the private sector to judge their commercial potential and readiness.[21] To date, there have been 45 demonstration projects under the program, including two commercial-size IGCC power plants, which are discussed below.[22]

1.3.1 Wabash River Coal Gasification Repowering Project[23]

This project, located in West Terre Haute, Indiana is a repowered,[24] 1950s vintage conventional coal-fueled plant, which was transformed from a 33% efficient, 90 MW unit to a nearly 39% efficient, 262 MW unit.[25] It began operation in November 1995. The total capital cost of the project was $438 million, of which DOE provided 50% ($219 million). It is owned by Global Energy USA. Cinergy, a large investor-owned utility that serves the area, dispatches power from the project into the transmission grid. The plant has a demonstrated heat rate of 8,910 Btu/kWh.[26] It has been operated successfully as both a base load and load following plant.[27]

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[20] The authorization for the Clean Coal Program was contained in the Department of Interior and Related Agencies Appropriation Act for FY1986, Pub. L. No. 99–190.
[21] See generally, John A. Herrick, Chief Counsel, Golden Field Office. Published in *Public Contract Law Journal*, Vol. 31, No. 2, Winter 2002
[22] In 2003, the Administration announced its support for a major new gasification demonstration project called FutureGen. For details see http://www.netl.doe.gov/coalpower/sequestration/futureGen/main.html
[23] See http://www.lanl.gov/projects/cctc/factsheets/wabsh/wabashrdemo.html
[24] Repowering a plant involves the installation of a new generating station on the site of an existing power plant. Depending on the characteristics of existing plant, some equipment may still be useful. In addition, the benefits of already having electric transmission access, water, coal pile areas, coal conveyer equipment, and an emissions envelope reduce siting, permitting and construction costs.
[25] Efficiency is the measure of how well a power plant converts fuel to electricity. If a plant achieved 100% efficiency, it would mean that all of the energy in the fuel would be converted into electricity.
[26] The "heat rate" measures how efficiently a plant uses fuel. Technically it is the number of British Thermal Units (Btus) of fuel required to produce one kilowatt-hour of electricity. To put it in perspective, the most efficient natural gas combined cycle plants can achieve heat rates as low as 6,500 (good), while a World War II vintage oil fired plant may have a heat rate as high as 13,000 (poor). In other words, the gas plant generates twice the amount of electricity with the same thermal amount of fuel. If the price of

Plant availability has been 70% or more.[28] Environmental performance has been excellent with regard to emissions of sulfur oxides, nitrogen oxides and particulates.[29] Sulfur oxide emissions were held below 10% of permitted limits by capturing 99% of the sulfur contained in the coal. Nitrogen oxide emissions have been reduced to the point where the plant meets all New Source Performance Standards.[30] The levels of particulate emissions have been extremely low.

1.3.1 Tampa Electric Company Polk IGCC Project[31]

This 250 MW power plant is located in Polk County, Florida. It is a greenfield project.[32] Construction began in 1994 and operations started in July 1996. Of the $303 million total project cost, $151 million, or 49%, was provided by DOE. The Polk plant has had a very good record of operation, achieving 80% availability. The overall heat rate is 9,350 Btu/kWh. It is the lowest cost generator on Tampa Electric's system. As in the case of the Wabash River plant, environmental performance has been excellent.[33] Emissions of sulfur oxides, nitrogen oxides, and particulates are well below the regulatory limits set for the Polk plant site. Sulfur oxide emissions reduction of 95% was achieved.

1.4 Current Use of Gasification Technology

Gasification technology is now being widely used throughout the world. A study performed for DOE and the Gasification Technologies Council by SFA Pacific indicated that 131 commercial gasification projects, with 409 individual gasifiers, were operating in 2001.[34] As shown in Figure 1.2, the total capacity of these plants was 40,000 MW (thermal) in 2001.[35] Further, another 32 projects, with 59 individual gasifiers, were in various stages of development, design and construction.[36] The additional projects would raise total capacity to 60,000 MW (thermal).

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coal were $1.20 per MMBtu (which is essentially accurate), the fuel cost of electricity produced by a plant (fuel only) with a heat rate of 8,910 Btu/KWh would be about 1.0 cent per KWh.

[27] C. Keeler, *Wabash River Report on 2002-03 Operating Experience*, presented at the Gasification Technologies Conference, October 13, 2003. A baseload plant runs almost constantly and is used to meet the minimum demand levels required by consumers on an around-the-clock basis, whereas a load following plant is one that provides electric power to follow the short-term changes in demand. Most conventional coal-fueled power plants run only as baseload units, which indicates that IGCC units can operate with much more flexibility than conventional plants.

[28] Availability indicates the amount of the time that a plant is available to operate. If a plant were able to operate every hour of a given year, the availability for that year would be 100%. Planned or unplanned "outages" for maintenance or repairs commonly affect plant availability.

[29] Jay Ratafia-Brown, et al., *Major Environmental Aspects of Gasification-Based Power Generation Technologies--Final Report*, December 2002, prepared for Gasification Technologies Program, National Energy Technology Laboratory, U.S. Department of Energy, pp. ES-3 to ES-4.

[30] New Source Performance Standards are those environmental requirements that a new power plant must meet to be permitted under the Clean Air Act as amended.

[31] See http://www.lanl.gov/projects/cctc/factsheets/tampa/documents/tampa.pdf

[32] A "greenfield" project is one built in an area where no other development has taken place, while a "brownfield" project is one built on a previously developed industrial site. Thus, any repowering project is a brownfield project.

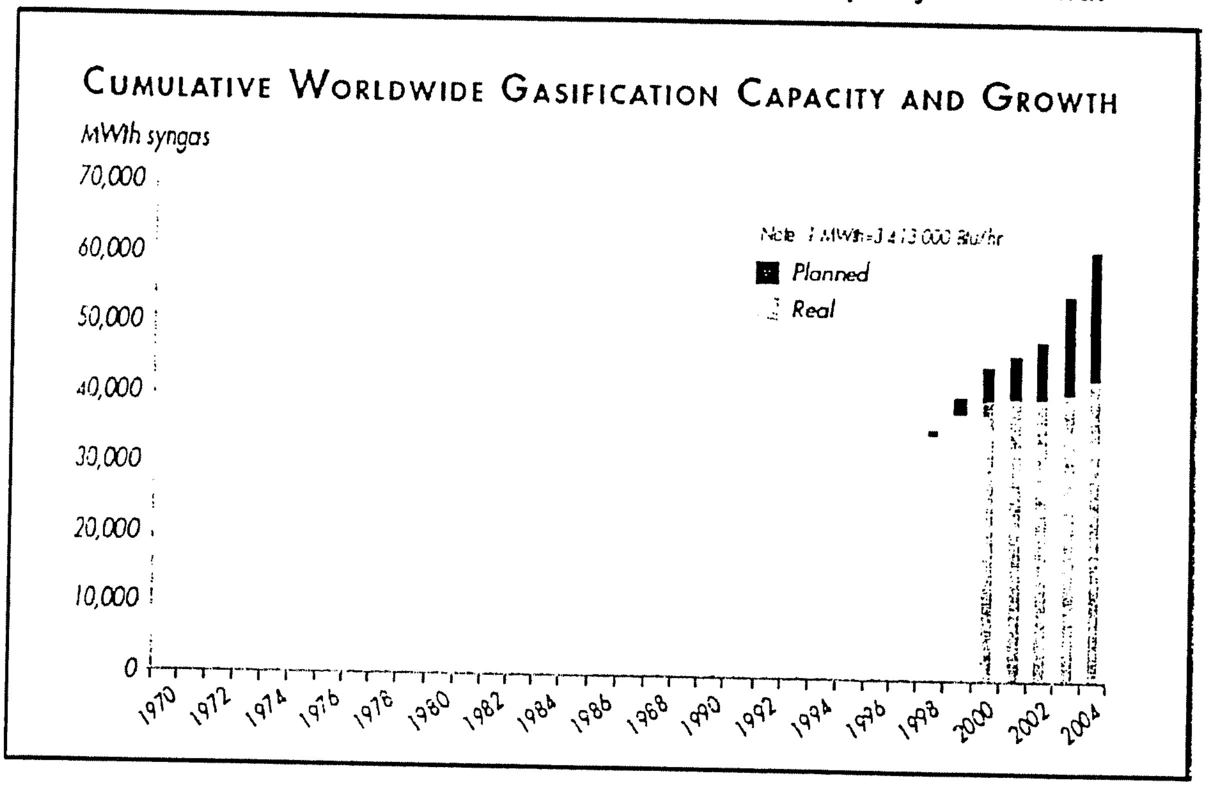
[33] Ratifia-Brown, op. cit.

[34] *Gasification Worldwide Use and Acceptance*, SFA Pacific, January 2000, DOE Contract DE-AM-98FE65271.

[35] If the efficiency of the electric generators were 100%, thermal and electric MW measures would be equal. Since the efficiency of IGCC power plants is less than 100%, the MW of electricity that can be produced is less that the MW of thermal energy that is input.

[36] As of 1989, about half of the syngas produced globally was used as a feedstock for chemical production. According to the Gasification Technologies Council, "the overwhelming majority of post-1990 new capacity in the [gasification] industry has been devoted to the production of chemicals and power."

Figure 1.2—Cumulative Worldwide Gasification Capacity and Growth



This total projected capacity would provide sufficient syngas to generate more than 33,000 MW of electricity if the syngas were used solely for power production. To put this in perspective, the peak demand for the entire State of New York is approximately 30,000 MW.

As shown in Figure 1.3, the main output of gasification plants is currently chemicals. The chemical products include hydrogen, ammonia, methanol, oxychemicals, carbon monoxide, and acetyls. Electric power is the second most widely produced output. The gasification plants also produce liquid fuels such as gasoline and diesel fuels using the F-T process.[37]

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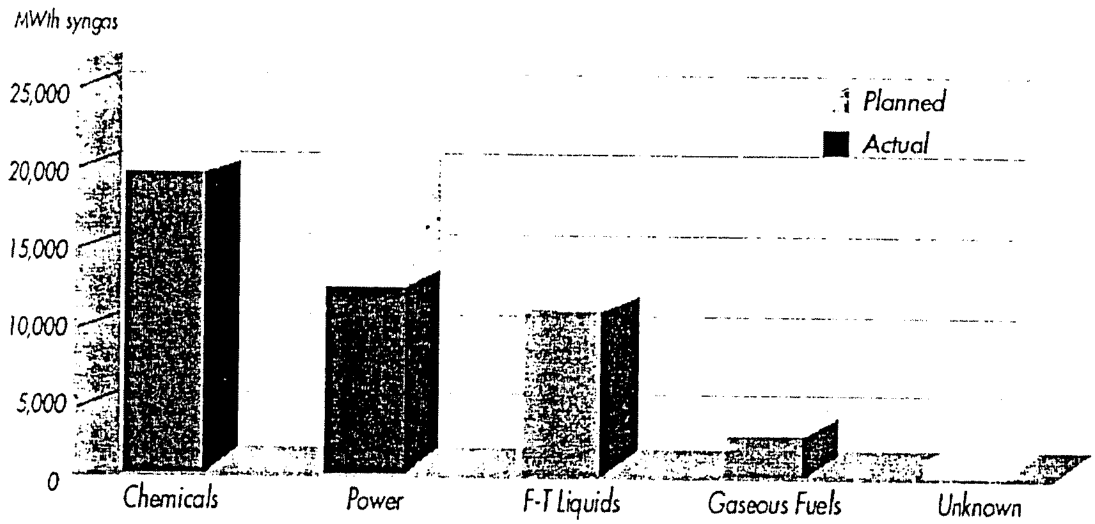
[37] The F-T process was developed by the German chemists Franz Fischer and Hans Tropsch in 1923. The process converts syngas into a clean, easily transported, petroleum-like liquid that can be refined to create fuels and other products. Although the process was developed 80 years ago, it has not been applied widely because it has been prohibitively expensive. Only in a few cases, when countries were cut off from the world oil market, have liquid fuels been produced in this way. Germany used F-T technology during World War II to make gasoline from coal-derived syngas and South Africa used it during the apartheid era. The potential for employing coal gasification to produce transportation fuels and thereby address the energy independence issue is discussed in Section 2 of this Report.

Figure 1.3 - Gasification by Application



Worldwide, the total capacity of the IGCC plants in operation is 5,808 MW, as shown in Table 1.1, which is equivalent to approximately 12,000 MW (thermal). There are also a number of other IGCC plants in the planning stage, with a total capacity of 4,994 MW. In addition to the coal-fueled IGCC plants noted above, nine gasification plants produce electricity from gasification of petcoke[38] and 13 from gasification of petroleum. The vast majority of the existing plants and new projects are in the U.S. and Europe.

Table 1.1 - Existing and Planned IGCC Electric Power Plants[39]

Country	Existing (MW electric)	Planned (MW electric)
Czech Republic	351	400
Finland	26	-
France	567	-
Germany	-	282
India	60	397
Italy	1484	605
Japan	343	476
Netherlands	254	26
Poland	-	504
Singapore	199	-
Spain	1224	-
UK	144	421
US	1156	1883
TOTAL	**5808**	**4994**

[38] Petroleum Coke (Petcoke) is a residue high in carbon content and low in hydrogen. It is the final product of thermal distillation of crude oil into various hydrocarbons--e.g., the separation of No. 6 oil into smaller hydrocarbons like No. 2 oil and gasoline. Approximately 40,000 tons per day of petcoke are produced in the U.S.

[39] Derived from the SFA Database.

1.5 Current Research to Improve Coal Gasification IGCC Performance

There are substantial programs in place in the U.S. for funding demonstration projects and for conducting research to improve the efficiency and cost effectiveness of IGCC power generation technology. Two areas of research, in particular, are likely to produce significant improvements that will be available for the next generation of commercialized IGCC power plants: (1) air separation (separating air into oxygen and nitrogen); and (2) syngas cleanup (removing pollutants and particles that could damage the gas turbine).[40]

1.5.1 Air Separation

Air separation provides the pure oxygen that is used to produce syngas in a high temperature/oxygen-controlled environment. Currently, air separation is achieved by using a cryogenic (very low temperature) process in which air is cooled to a liquid state and then subjected to distillation.[41] However, the cryogenic process (i.e., the "Air Separation Unit" or "ASU") requires a large amount of power. In the case of the Polk Plant, almost 20% of the unit's total electric output is used to produce the pure oxygen and nitrogen needed to run the facility.[42] In addition to decreasing the plant's net output, the cryogenic ASU can add as much as 15% to the unit's capital cost. For these reasons, lowering the cost of air separation will significantly improve the economics and efficiency of IGCC power plants and their commercial viability.

The DOE is conducting research on improving air separation technology. Its membrane-based oxygen project will scale-up and demonstrate new air separation technology for the large-scale production of oxygen from air. Recent analyses on a variety of gasification-based processes show significant cost and efficiency advantages with the application of high-temperature membranes for oxygen production compared to conventional cryogenic technology.[43] Full-scale membranes that meet or exceed commercial targets have been fabricated and modules are being developed for scale-up to 1-5 tons/day of oxygen production.[44] The upgrade in air separation technology will significantly improve the economics of IGCC compared with current ASUs.

1.5.2 Syngas Cleanup

Another significant area of potential improvement in IGCC technology involves the process of syngas cleanup.[45] As previously discussed, particulate materials must be removed before the syngas produced by the gasifier can be injected into the gas turbine to avoid damaging the turbine. In addition, depending on the configuration of the IGCC facility, pollutants such as sulfur and mercury can be removed in the syngas cleanup phase. This is generally

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[40] Other research areas include advanced gas turbine designs and carbon sequestration among others.
[41] Distillation is a process that separates a mixture of liquids with different boiling points by heating the mixture, removing the lowest boiling point liquids first, and then successively taking off higher boiling point liquids. Atmospheric air is about 80% nitrogen and 20% oxygen. Nitrogen boils at a lower temperature than oxygen. Thus, when air is liquefied at very cold temperatures and the temperature of the liquid air is raised to the boiling point of nitrogen, the nitrogen is distilled off and oxygen remains.
[42] The Polk Plant generates total power of about 310 MW. However, 60 MW are used to produce the pure oxygen. Thus, the net electric output of the plant is 250 MW. Accordingly, the air separation unit is considered "highly parasitic."
[43] See NETL URL http://www.netl.doe.gov/coalpower/gasification/pubs/success.html
[44] Id.
[45] See Bruijn et al, *Treating Options for Syngas*, presented at the Gasification Technologies Conference, October 12-15, 2003.

accomplished now by cooling the syngas to much lower temperatures, and then using conventional cleaning methods including cyclones[46] and scrubbers.[47]

DOE is currently working on syngas cleanup systems in which the syngas will need to be cooled only moderately.[48] Such a system would be thermodynamically superior to and potentially less complex than current cooled gas cleanup processes. Once these technologies are perfected, the economics and environmental friendliness of IGCC power plant technology will improve considerably.

1.6 Co-Production Capabilities

As previously discussed, the gasification process can be engineered to be very flexible. A plant that is equipped to do so can vary the amount of power, fuels, gases or other products that are produced from coal at given times to maximize return on investment.[49] Figure 1.4 illustrates the wide range of products that can be produced by an IGCC power plant if co-production is used. Research has shown that large potential economic gains can be obtained through the production of both electric power and FT liquids, and, in turn, the production of diesel and other transportation fuels from FT liquids.[50]

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[46] A cyclone is a cylindrical device that takes a high-speed flow of air and particulates from a gasifier, spins it, and slows down the velocity. At slower speeds, particulate materials fall to the bottom and are removed.

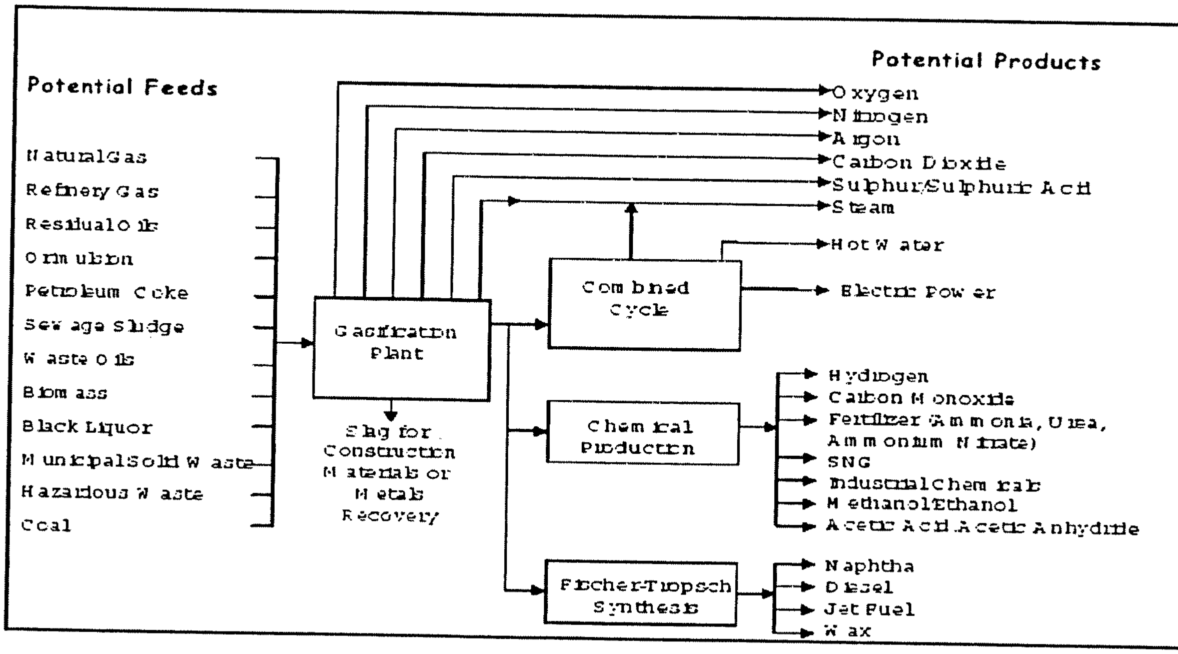
[47] A scrubber is used to remove sulfur oxides, which can cause acid rain among other pollutants. At the Polk Plant, syngas moves from the gasifier to a high-temperature heat-recovery unit, which cools the syngas while generating high-pressure steam. The cooled gases flow to a water wash for particulate removal. Next, a hydrolysis reactor converts one of the sulfur species in the gas to a form that is more easily removed. The syngas is then cooled further before entering a conventional amine sulfur removal system. The amine system keeps sulfur oxides emissions below 0.15 $lb/10^6$ Btu (97% capture). The cleaned gases are then reheated and routed to a combined-cycle system for power generation.

[48] Dale Simbeck, SFA Pacific, Inc., *Industrial Perspective on Hot Gas Cleanup*, Presentation at the 5th International Symposium on Gas Cleaning at High Temperatures, U. S. DOE National Energy Technology Laboratory, September 18, 2002.

[49] Since the Wabash plant has been operated in a "load following" mode, it is likely that the generation component can be brought into operation very quickly. This means that the facility may be able to sell ancillary services such as spinning and standby reserve, and collect payments for providing that service, while still producing other fuels.

[50] See generally, David Grey and Glen Tomlinson, *Efficient and Environmentally Sound Use of Our Domestic Coal and Natural Gas Resources*, Energeia, University of Kentucky, Center for Applied Research, Vol. 8, No. 4, 1997. The F-T process can produce a number of commercially valuable fuels including methanol and other hydrocarbons, hydrogen and other products.

Figure 1.4--Co-Production Capabilities of IGCC Technology[51]



A co-production system can be adjusted to produce electric power when power prices are high (i.e., peak periods) and use the full syngas output to produce diesel fuel during off-peak periods when electricity prices are low. Diesel fuel production from gasification would become especially valuable under pending diesel fuel standards,[52] since the fuel is very clean and would meet those environmental requirements without modifications.

The co-production of diesel fuel from IGCC facilities could also be very valuable in reducing U.S. reliance on imported fuels. According to the Energy Information Administration (EIA), total "on highway" diesel fuel consumption in the U.S. in 1999 was approximately 2.1 million barrels per day.[53] Based on current research, a 400 MW IGCC co-production facility producing electricity and diesel fuel could produce approximately 6,000 barrels per day of diesel fuel and 9,600 MWh per day of electricity.[54] Theoretically, with 50 such facilities in place--representing 20,000 MW of electric generating capacity--about 300,000 barrels per day of diesel fuel could be produced. That would displace about 14% of the daily "on highway" diesel transportation fuel consumption in the nation.

1.7 Energy Tax Policy and IGCC

The federal government and the states have used energy tax policy to accomplish many goals. The history of employing such measures is well documented in a study by prepared for the Congressional Research Service.[55] Energy taxes and subsidies have been designed to either correct problems or distortions in the energy markets or to achieve social, economic,

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[51] From G. Phillips, *Gasification Offers Integration Opportunities and Refinery Modernization*, presented at Protech 2001, October 2001.
[52] Final Rulemaking on Heavy-Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements, issued December 2000. 40 CFR Parts 69, 80, and 86.
[53] Energy Information Administration, *Fuel Oil and Kerosene Sales 1999*, DOE/EIA-0535 (99), Table 4 (Washington, DC, June 2000).
[54] Grey and Tomlinson, op. cit.
[55] Salvatore Lazzari, *Energy Tax Policy*, Congressional Research Service, IB10054, January 2, 2003.

environmental, or fiscal objectives. This Report will focus on tax incentives for alternative fuels, including the production of syngas and eventually electricity from coal.

After the energy crises of the 1970s, the federal government sought to address the ripple effects of stagflation, energy shortages, productivity problems and dependence on oil imports, among others. The Energy Tax Act of 1978 and the Windfall Profits Tax legislation enacted in 1980, authorized "Section 29" tax credits for producing "unconventional fuels," including production of syngas from coal, to decrease U.S. dependence on energy imports. The credits were set at a certain dollar amount per unit of coal consumed and syngas produced, adjusted for inflation.[56] Like other energy tax measures, the intent behind this tax credit program was to stimulate private investment in energy conservation, to promote energy production from renewable resources, and to develop non-conventional energy sources including production of syngas from coal. The legislation also made tax-exempt financing available for facilities using solid wastes to produce fuels.

Later in the 1980s, as the energy crises of the 1970s abated, all energy tax credits that were scheduled to expire were allowed to do so.[57] However, credits for solar, geothermal, ocean thermal and biomass technologies were extended, and the Section 29 credits remained in place. Several amendments to the Internal Revenue Service's (IRS's) Section 29 regulations enhanced the utilization of the coal industry's tax credit. First, the program eventually was extended to include facilities that were online by June 30, 1998, with the tax credit applicable for 10 years following that date. Subsequently, a ruling by the IRS in the mid-1990s permitted the use of limited partnerships as a means of raising capital, thereby decreasing the investment burden, and facilitating the sharing or selling of the tax credit.[58]

Section 29 credits are deducted on the owner's tax return or sold to another entity, and are honored for the term of the credits granted. The tax credit was set in 1980 at $3 for the equivalent of each barrel of oil related to a qualified fuel, with this value adjusted annually based on the inflation rate. A barrel of oil contains 5.8 MMBtu, while a ton of common coal contains 24 MMBtu.[59] Thus, the initial $3 per barrel equivalent credit equated to a $12.41-per-ton tax credit for each ton of synthetic coal-based fuel produced. Based on the inflation adjustment, the current tax credit equates to a $24.62-per-ton tax credit for common synthetic coal-based fuel. This credit is approximately equal to the cost of common grade coal, which is in the range of $20-$30 per ton delivered to a power plant. As a result of the credit, some facilities pay a net of zero dollars for their fuel since the credit offsets their entire fuel cost.

The Section 29 credit was extended under the Revenue Provisions of the Omnibus Reconciliation Act in 1990 and under the Energy Policy Act of 1992. Under current statutory authority, no new Section 29 credits can be granted until new legislation is enacted and the President signs it into law.

New tax credit provisions are being considered as part of proposed omnibus energy policy legislation. In the Senate draft, the owner of electric generation from a syngas facility would

[56] These credits also apply to oil extracted from shale or tar sands; gas produced from geo-pressurized brine, Devonian shale, tight formations, and coal bed methane; gas from biomass; and synthetic fuels from coal. Mark Morey, *Coal-based Synfuel Continues to Grow*, Coal Age, Nov. 1, 2002.

[57] All existing syngas production credits are scheduled to expire in 2008.

[58] See generally, G. William Kalb, *Tax Credit Plants Emerge*, Coal Age, April 1, 2000.

[59] Oil is currently selling for $25-30 per barrel (5.8 million Btus), while a ton of coal delivered to a power plant (24 million Btus) is about the same price. However, a ton of coal contains approximately four times the fuel value in Btus. By comparison, one million Btus of natural gas sells for as much as $7, which is five to seven times the price of one million Btus of coal.

receive a credit of $3.40 per MWh produced, adjusted for inflation.[60] In addition, there are terms that would provide credits for the sale of syngas, chemicals and fuels by a co-production facility. However, no action has yet been taken on the Energy Bill. While it is not clear what form of tax incentive will be eventually be adopted, it appears likely that an extension of the incentives will ultimately be codified.

1.8 Summary

Research and development, demonstration projects, financial support, and tax credits funded by the federal government have brought the production of electricity from coal in IGCC power plants to the point where it is technologically and economically feasible. Nevertheless, although this technology has been used successfully on a commercial scale and holds the promise for major benefits in the areas of environmental protection, technology advancement, economic growth, and national security, there are still significant challenges to its more extensive deployment. Consequently, building upon what has been accomplished to date, a range of new policies must be formulated and implemented to address these challenges.

[60] HR 6 Conference Report from Fall Term 2003.

SECTION 2.

BENEFITS OF IGCC DEPLOYMENT

The development and deployment of commercial-scale IGCC electric generating plants will produce major benefits in four key areas: (1) environmental, (2) technology advancement, (3) economic, and (4) national security. This section of this Report discusses those benefits. It provides the context for examining the challenges to deploying IGCC power plants and the development of strategies for addressing them.

2.1 Environmental Benefits

Although coal is the nation's most abundant energy resource, the use of conventional coal-fueled power plants entails significant environmental consequences. Such facilities emit sulfur oxides, nitrogen oxides, particulates, mercury, and carbon dioxide, release hazardous materials into water systems, and produce large quantities of solid wastes that need to be safely disposed of. In contrast, existing commercial size IGCC power plants--the Polk facility in Florida and the Wabash River plant in Indiana described in the previous Section--produce substantially lower levels of pollutants and wastes than conventional coal-fueled units. Further, much of the solid waste material produced by IGCC units is commercially salable, thereby reducing or largely obviating waste disposal costs. While pollutants from combustion-based units other than IGCC facilities can be reduced by newer technologies, retrofitting such plants to address each of these emissions in a piecemeal manner may cost considerably more than repowering them with IGCC technology, depending upon the age and size of the plants and their current levels of performance.[61]

In addition, IGCC power plants have major advantages over current combustion-based technology in capturing carbon dioxide. The higher concentration of carbon dioxide and higher operating pressure of an IGCC coal-fueled power plant makes it much easier and far less costly to separate and capture carbon dioxide than in a conventional coal-fueled unit or a natural gas combined cycle ("NGCC") facility. This capability could be taken into account in new generation technology deployment determinations, although large-scale carbon dioxide sequestration is not yet been demonstrated to be cost-effective and carbon dioxide reductions in the U.S. are currently voluntary.[62]

The environmental benefits of IGCC electric power plants are documented in a comprehensive report by Jay Ratifia-Brown, et al., dated December 2002, prepared for NETL. ("Ratifia-Brown Report")[63] The discussion of environmental issues here relies heavily on that study. Readers seeking more detailed information on these matters are referred to the Ratafia-Brown Report.

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[61] Dale Simbeck, *Gasification Repowering, The Innovative Option for Old Existing Coal-Fired Power Plants*, presented at the NEMS/Annual Energy Outlook 2003 Conference, March 18,2003, SFA Pacific.
[62] See M.D. Rutkowski et al, *Pre-Investment of IGCC for CO_2 Capture with the Potential for Hydrogen Co-Production*, presented at the Gasification Technologies Conference, October 2003.
[63] Jay Ratafia-Brown, et al., *Major Environmental Aspects of Gasification-Based Power Generation Technologies--Final Report*, December 2002, prepared for Gasification Technologies Program, National Energy Technology Laboratory, U.S. Department of Energy.
www.netl.doe.gov/coalpower/gasification/pubs/pdf/final%20env.pdf.

2.1.1 Air Quality

2.1.1.1 Sulfur Oxides and Nitrogen Oxides

The environmental performance of the Polk and Wabash River IGCC power plants has been excellent. As shown in Table 2.1, projected ICGG plant sulfur oxide emissions are 93% below existing Federal New Source Performance Standards ("NSPS") limits for coal-based combustion facilities, and nitrogen oxide emissions are 40% below those NSPS standards.[64]

Table 2.1 - Emissions of Sulfur Oxides and Nitrogen Oxides[65]

	Projected IGCC Emission Levels	Coal Combustion-Based NSPS Limit
Sulfur oxides	0.08 lb/10^6 Btu	1.2 lb/10^6 Btu
Nitrogen oxides	0.09 lb/10^6 Btu	0.15 lb/10^6 Btu

The benefit of using IGCC units in lieu of other coal-based technologies could be undermined if the standards governing natural gas-fired combustion turbines were applied to the CT component of IGCC facilities, which produces most of its air emissions. The Best Available Control Technology ("BACT") standard for natural gas combustion turbines is currently in the range of 2-4 ppm for nitrogen oxides, below the level that currently can be achieved by IGCC plants.[66] However, the BACT standard for natural gas combustion turbines is not appropriate for IGCC facilities.[67] Although IGCC nitrogen oxide emissions are relatively low compared with those allowed for other coal-fueled plants, enhanced control technology would probably be needed if regulators required that IGCC facilities meet the BACT standards as applied to natural gas-fired combustion turbines. The current state-of-the-art control for syngas-fueled turbines utilizes diluents, such as nitrogen or steam, to reduce nitrogen oxide emission levels to approximately 15 ppm. This approach has been adopted in the final nitrogen oxide BACT determination for the Polk plant, and could serve as precedent in future permitting of IGCC power plants.

2.1.1.2 Carbon Dioxide

While not currently required, the capture of carbon dioxide--sequestration--may become an important factor in the next decade as concern over global warming grows and trading of carbon emissions develops and expands. As noted above in Section 1.2.2, processes for the capture of carbon dioxide are already in place at the Great Plains Synfuels Plant in North Dakota, where carbon dioxide is separated out and then transported through a pipeline to Saskatchewan, where it is used for enhanced oil recovery.

IGCC power plants can provide major advantages over combustion-based technology in this regard, since it easier to separate and capture carbon dioxide from syngas than from flue gas.

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[64] Although the NSPS standards may not necessarily apply to new IGCC power plants, they nevertheless provide a useful benchmark.

[65] Ratifia-Brown, et al., op. cit., p. ES-4.

[66] Id., p. ES-9.

[67] Id., p. 2-39. The Lean-Premix Technology on which the BACT standard is based cannot be used in IGCC facilities because of the different characteristics of syngas and natural gas. The syngas that is burned in an IGCC combustion turbine differs from natural gas in terms of caloric value, gas composition, flammability characteristics, and contaminants.

This is attributable to two key factors: (1) the relatively higher carbon dioxide concentration of syngas, which can be increased further by converting carbon monoxide to carbon dioxide before combustion, while simultaneously producing more hydrogen (e.g., via water-gas shift); and (2) the relatively higher operating pressure of IGCC gasifiers.[68] Recent design studies have shown that carbon dioxide capture would reduce the net electricity output of an IGCC power plant by to about 14%, compared to reductions of 21% for a natural gas combined cycle unit and 28% for a conventional pulverized coal facility.[69]

In addition to carbon dioxide capture, application of IGCC technology can reduce carbon dioxide emissions by repowering existing coal-fueled units. The conversion and repowering of the Wabash River plant to an IGCC facility decreased carbon dioxide emissions by approximately 10% on a per MWh basis. These reductions arise purely as a result of efficiency gains in converting coal to electricity. If sequestration becomes economic, carbon dioxide emissions could be reduced very substantially from these levels.

2.1.1.3 Mercury

As discussed in Section 4.2.4.2, the EPA announced proposed new rules governing the emission of mercury from coal-fired power plants on December 15, 2003. Two alternative approaches were put forward. One would require coal-fired power plants to install currently available maximum achievable control technologies (MACT) for mercury. According to the EPA, this would reduce nationwide mercury emissions from an estimated 48 tons a year to 34 tons a year--a decrease of 29% by 2007. The second approach would set a mandatory, declining cap on total mercury emissions from coal-burning power plants nationwide. This approach, which would allow emissions trading, would reduce mercury emissions by nearly 70% from current levels once the final mercury cap takes effect in 2018.[70]

Environmental advocacy groups and some elected officials and state regulators are likely to challenge the proposed rules. They have contended that the MACT standard mandates a reduction of approximately 90% in power plant mercury emissions, noting that commercial methods used for many years to remove trace amounts of mercury from natural gas and gasifier syngas can achieve 90% to 95% removal efficiency and that several states have concluded that this level of reductions is achievable.[71] Further, environmental advocacy groups maintain that a cap-and-trade approach is inappropriate for controlling mercury emissions since it could allow "hot spots" of mercury contamination in lakes and rivers neighboring plants that buy pollution credits instead of reducing their mercury emissions.

The Ratafia-Brown Report estimates that the incremental cost of removing 90% of mercury emissions in an IGCC unit is about one-tenth the cost of comparable mercury removal in a flue gas based system used at a conventional coal-fueled plant.[72] This would result in substantial savings in emissions control costs over the life of the plant. Although the savings would be

[68] See generally, J. Davison and L. Bressan, *Coal Power Plants with CO_2 Capture: The IGCC Option*, presented at the Gasification Technologies Conference, October 2003.
[69] Ratifia-Brown, et al., op. cit, p. ES-8.

[70] EPA Fact Sheet, December 15, 2003, http://www.epa.gov/mercury/mercuryfact12-15final.pdf.; and U.S. Environmental Protection Agency, Headquarters Press Release, Washington, DC, For Release, 12/15/2003, *Clean Air Proposals Promise Sharp Power Plant Pollution Reductions* , see http://yosemite.epa.gov/opa/admpress.nsf/b1ab9f485b098972852562e7004dc686/b8860b2d46c43fa385256dfd007870df?OpenDocument

[71] See e.g., http://www.nescaum.org/newsroom/pr031104mercury.pdf; http://epw.senate.gov/108th/Jeffords_050803_3.htm; www.nrdc.org/media/pressrreleases/031205.asp.
[72] Id., op. cit., pp. ES-5, 2-45.

smaller to the extent that mercury reduction requirements were less than 90%, they would still be significant.

2.1.2 Water Quality

In general, an IGCC unit produces fewer water effluents than a conventional or fluidized bed combustion facility.[73] The Polk plant has a state-of-the-art system designed to completely eliminate process water discharge.[74] However, the plant has had a problem with process water run-off from its slag storage and process area, and has initiated remedial actions to address this matter. The Wabash River plant initially had out of compliance levels for arsenic, cyanide and selenium. This problem has been addressed through the installation of a water treatment system similar to the one used at the Polk unit.[75] Overall, water effluents from IGCC power plants are significantly less than from combustion-based coal facilities.

2.1.3 Solid Waste

In terms of solid wastes, operating experience indicates that IGCC power plants produce less environmental impacts than combustion-based coal power plants. Moreover, the main byproducts of IGCC power production--slag and sulfur--can be marketed commercially to help offset the plant's operating costs or, at a minimum, defray or eliminate disposal costs.[76] The slag produced by the Polk and Wabash River plants is highly non-leachable and therefore can be treated as a non-hazardous material. It is suitable for utilization in cement, asphalt, landfill cover or roofing material, and therefore has commercial value.

IGCC plants produce solid sulfur or sulfuric acid that is readily marketable. In contrast, other coal-fueled generation processes produce sulfur materials that have a significantly larger mass and volume, and are more difficult to handle and market. Disposal of these solid wastes is costly and may represent an environmental detriment that deployment of IGCC technology in the U.S. power sector could address.

2.2 Technology Benefits

IGCC technology is compatible with and complementary to the development of new energy technology in several critical areas. It will facilitate carbon dioxide sequestration, since IGCC technology can almost completely separate carbon dioxide from the bulk gaseous discharge stream. In addition, IGCC facilities can be used to coproduce liquid fuels and commodity chemicals. Further, since coal gasification can also produce pure hydrogen, IGCC power plants can play an integral role in establishing the "hydrogen economy."[77]

Hydrogen produced by IGCC power plants can be utilized in fuel cells. A fuel cell is a device that uses hydrogen (or hydrogen-rich fuel) and oxygen to create electricity by an electrochemical process. Several types of fuel cells are being developed for a variety of potential applications--e.g., in passenger vehicles, commercial buildings, homes, and even small devices such as laptop computers.

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[73] Ratifia-Brown, et al., op. cit., p. 2-58.
[74] Id., p. ES-6.
[75] Id., p. ES-6, p. 2-59.
[76] Id., pp. ES-6 to ES-7.
[77] For a wealth of resources concerning the progress and benefits of a hydrogen economy see the DOE web site http://www.eere.energy.gov/RE/hydrogen.html

Fuel cells can provide several substantial benefits over conventional combustion-based technologies currently used in many power plants and passenger vehicles. Fuel cells are more efficient, and the hydrogen used to power them can be obtained from a variety of sources, including IGCC power plants. Since the hydrogen fuel can be produced from domestically available coal and other sources such as municipal solid waste, fuel cells have the potential to improve national security by reducing U.S. dependence on energy imports.

Further, fuel cells produce much smaller quantities of greenhouse gases that contribute to global warming, and none of the air pollutants that create smog and cause health problems. In fact, if pure hydrogen is employed as a fuel, only heat and pure water are emitted as electricity is produced. Although the potential benefits of fuel cells are significant, many challenges, technical and otherwise, must be overcome before they will be a successful, competitive alternative for consumers. These include cost, durability, fuel storage and delivery issues, and public acceptance.[78]

The rapid commercialization and deployment of IGCC technology in the U.S. power sector could increase the rate at which fuel cell technology will develop. The DOE has approved plans to deliver and operate a 2 MW fuel cell to be linked to the Wabash IGCC power plant.[79] A one-year test program will begin soon after the fuel cell goes into operation and is connected to the coal gasification system's syngas output. After the test period, Wabash plans to leave the fuel cell in place and use its electrical output to operate the plant.

2.3 Economic Benefits

Repowering the existing fleet of older, conventional coal-fueled plants with IGCC technology would provide an opportunity to address a number of environmental problems going forward. This would very likely involve a substantially lower cost than piecemeal, incremental retrofits of those facilities to meet specific emissions requirements one at a time, accounting also for a significant increase in repowered generating capacity compared to the original plant.

The use of IGCC technology would also reduce reliance on natural gas for electricity generation, and free up natural gas for more efficient uses such as industrial processes and residential heating. Not only is coal far less expensive than natural gas, it is also a far more abundant domestic resource.

Over the past decade, coal prices have declined sharply and are expected to continue to do so,[80] whereas the price of natural gas has increased dramatically.[81] While coal prices are projected to decrease over the next 20 years, many experts forecast that natural gas prices will continue to increase over that period due to supply-demand imbalance, which is exacerbated by the growing use of natural gas for electricity production.[82] Further, natural gas prices have recently been highly volatile, whereas coal prices tend to be stable and predictable.

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[78] *A National Vision Of America's Transition To A Hydrogen Economy —To 2030 And Beyond*, February 2002, based on the National Hydrogen Vision Meeting Washington, D.C., November 15-16, 2001, United States Department of Energy.

[79] NETL, *Wabash River Plant in Indiana to Host 1st Clean Coal-Powered Fuel Cell*, Techline, July 30, 2002.

[80] Testimony of Mary Hutzler, Director EIA, before House Subcommittee on Energy and Air Quality, March 14, 2001. See also EIA, *Annual Energy Outlook 2003*.

[81] The average price of natural gas for the period 1995-2000 was $2.78 per MMBtu, while the average for 2001-2003 was $4.40 per MMBtu. See Dismukes, *Affordable Energy: The Key Component of a Strong Economy*, presented at NARUC Annual Meeting, November 16-19, 2003.

[82] For example, see Andrew Weissman, *The Coming Natural Gas Crisis*, Energy Pulse, December 19, 2002.

Since coal is predominately a domestic fuel source, expanding its use in electricity production will have the effect of increasing U.S. employment. With coal reserves in 38 states, this benefit will be experienced in most parts of the nation.[83]

Previously, one of the main challenges to the development and deployment of IGCC power plants was that the capital costs of such facilities were significantly higher than the capital costs of natural gas-fired generating units, thereby negating the fuel cost savings that could be realized from IGCC facilities. That will most likely not be the case if natural gas prices remain substantially above $4.00 per MMBtu. Moreover, the per unit capital costs of IGCC power plants are likely to decline considerably as more of these facilities are built, standard designs are developed, and economies of scale are realized. As a result, the economic development advantages of increased utilization of coal in electricity production will become more significant.

The rapid commercialization and deployment of IGCC power plant technology in the U.S. could also lead to valuable foreign trade opportunities. This would bolster U.S. exports and contribute to growth in domestic employment. The potential for IGCC power plant exports is vast. Countries like China, which have abundant coal reserves and little oil or natural gas, will be building many new coal-fueled power plants. For example, it has been reported that China is planning on adding 30,000 MW of generating capacity every year for the next three years.[84] This could provide a very large market for state-of-the-art IGCC power plants that operate efficiently and produce substantially lower emissions than combustion-type, coal-fueled facilities.[85]

2.4 National Security Benefits

Expanded utilization of IGCC power plants would be valuable in decreasing U.S. dependence on imported fuel and reducing vulnerability to disruptions of energy supplies.

2.4.1 Decreased Dependence on Imported Fuel

As discussed in Section 4.2.5.1, the growing reliance on natural gas-fired electricity generation, which has accounted for most of the new power plants built in recent years, is placing a strain on U.S. gas supplies and reserves. This has serious national security implications.

In recent testimony before Congress, Federal Reserve Chairman Alan Greenspan noted that continued growth of natural gas consumption could necessitate additional imports.[86] This would require creating new and expensive infrastructure, including construction of a fleet of large tankers capable of transporting liquefied natural gas (LNG) and special port facilities to handle LNG shipments, as well as relying on unstable areas where much of the world's natural gas reserves are located. As a result, the U.S. would be more vulnerable to disruptions in supplies of vital energy resources.

Additionally, as discussed above in Section 1.5, IGCC power plants could produce substantial quantities of diesel fuels and thereby reduce oil imports. Based on current research, a 400 MW

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[83] Information regarding the economic development impacts of expanding coal utilization is detailed in Rose and Yang, *Projected Economic Impacts of U.S. Coal Production and Utilization*, Pennsylvania State University, 2002.
[84] M. Mudd, *Sequestration Update*, presented at the MARC/NARUC Conference, June 2003.
[85] The Chinese government has recently indicated an interest in lowering air pollution by issuing stronger mileage standards for sports utility vehicles than the U.S. currently has in place.
[86] Alan Greenspan, Testimony before the House Committee on Energy and Commerce, June 10, 2003.

IGCC electricity and diesel fuel co-production facility could produce approximately 6,000 barrels per day of diesel fuel and 9,600 MWh per day of electricity.[87] Theoretically, with 50 such facilities in place--representing 20,000 MW of electric generating capacity--about 300,000 barrels per day of diesel fuel could be produced. That would displace about 14% of the daily "on highway" diesel transportation fuel consumption in the nation.

U.S. coal supplies are abundant, with reserves currently estimated at over 275 years at current consumption rates.[88] Accordingly, coal can probably meet U.S. fuel requirements for at least the next two centuries even at increased consumption rates, without fear of shortages, international disruptions, or continuing reliance on imported sources. Increased use of coal will greatly enhance U.S. national security.

2.4.2 Reduced Infrastructure Vulnerability

The extraction and delivery infrastructure for coal is markedly less vulnerable to terrorist threats than that of natural gas or oil. Natural gas and oil must be transported through thousands of miles of pipelines or tankers at sea, which are susceptible to sabotage and would require considerable time for repairs in the event of damage. In contrast, coal is available domestically in abundant fields and mines, and can be transported in a variety of ways including rail and barge. Disruption of the coal extraction and delivery infrastructure could be more easily repaired, without significantly impacting fuel supplies. In addition, a common practice in the coal power plant operations is to keep a 60-90 day supply of coal on site so that a disruption of incoming supplies would have a minimal impact.

2.5 Summary

The benefits of using IGCC power plants discussed in this Section have enormous potential value for the U.S. in terms of the environment, technological advancement, the economy, and national security. Accordingly, it is critical to identify the challenges to expanded IGCC deployment, and develop appropriate measures and policies for overcoming them. These matters are addressed in the next two Sections of this Report.

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[87] Grey and Tomlinson, op. cit.
[88] EIA, Annual Energy Review 2000

SECTION 3.
IDENTIFICATION AND RANKING OF CHALLENGES

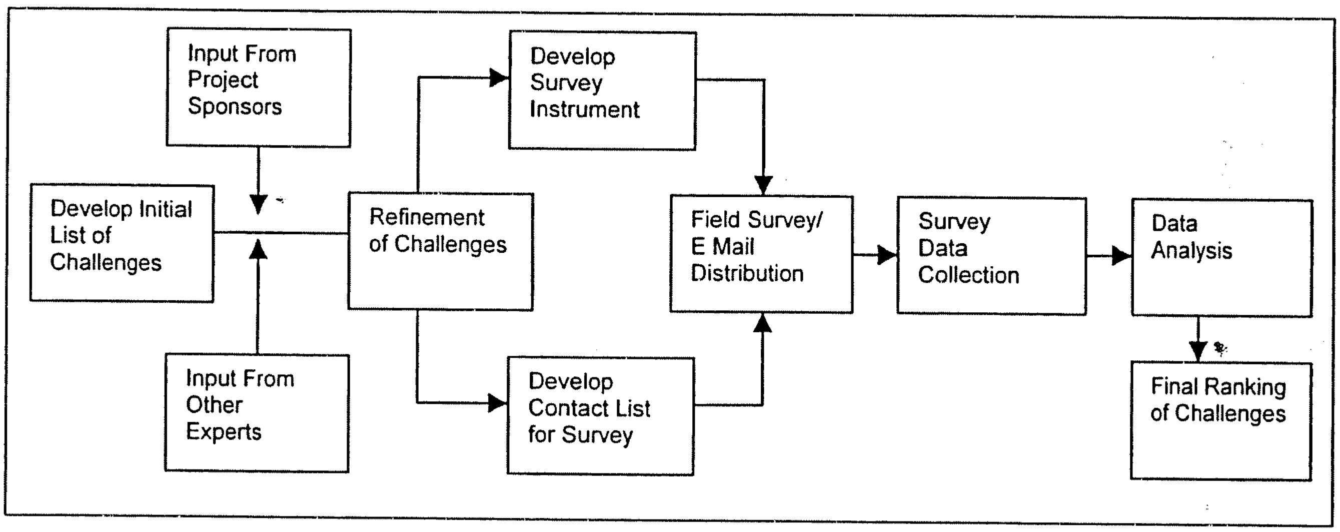
3.1. Background

A key component of this study was the systematic identification and prioritization of the challenges that must be overcome to expand deployment of IGCC power plants. This was done by surveying a wide range of IGCC experts and institutional stakeholders. The survey was designed to rank each of the challenges in accordance with its relative significance. The survey results provide the framework for developing strategies and policies to achieve the environmental, technological, economic, and national security benefits of IGCC deployment. This Section of the Report discusses the development of the survey, the survey results, and the differences in survey responses among the various groups of participants (i.e., government/regulators, energy companies, technology/engineering, and consulting/financial).

3.2. Development of the Survey

The survey was developed through a comprehensive, sequential research design process, which is shown in Figure 3.1 below.

Figure 3.1—Research Design Framework



3.2.1. Identification of Challenges to IGCC Deployment

The survey process was initiated by developing a strawman list of "barriers" to IGCC power plant deployment. The list was based on a broad review of relevant literature, and discussions with experts and institutional stakeholders. It was then reviewed by the project sponsors. The list served as a set of preliminary hypotheses to be tested through the survey process. The final list included 97 items and was organized into six categories, as shown in Table 3.1.

Table 3.1—Items Incorporated in the Survey

Type of Item	Description	Number of Individual Items Examined
Legal/Regulatory	Items related to the regulatory and legal processes, including plant siting procedures, standard market design, electric industry restructuring, and uncertainty over regulatory treatment.	13
Environmental	Items associated with environmental concerns, including emissions (carbon dioxide, mercury, nitrogen oxides, sulfur oxides, particulates), the concern over the environmental permitting process, and uncertain environmental rules and enforcement.	16
Financial	Items tied to financial considerations, including tax issues, credit concerns, project finance, the market for emissions credits, licensing fees, and cost of operation.	29
Economic	Items associated with plant factors such as fuel costs, demand growth, transportation costs, and impacts of the country's overall economy.	11
Cultural	Items linked to cultural concerns, including regulator viewpoints, public perception, corporate culture of plant developers, and past failures, and difficulties of IGCC plants.	17
Technological	Items associated with the IGCC technology, including maturity of the technology, lack of needed transport plans, and limited IGCC plant operating experience.	11
Total		**97**

3.2.2. Survey Instrument Development

The survey instrument was designed to solicit the views of experts and institutional stakeholders on the factors impeding the deployment of IGCC power plants. Respondents were asked to rank the relative importance of each of the listed items using a Lickert Scale of one (least significance) to five (highly significant). In addition, respondents were given the opportunity to provide open-ended comments detailing any of the items. A copy of the survey instrument is presented in Appendix A.

3.2.3. Survey Participants

The survey was e-mailed to a database of 143 experts and institutional stakeholders. In addition, the survey was provided to various state energy officials and members of the coal industry through the auspices of the Southern States Energy Board. The list of experts and institutional stakeholders was developed through ongoing discussions with and suggestions from project sponsors. It included individuals representing the following types of businesses and organizations, as shown in Table 3.2.

Table 3.2—Survey Participants

Types of Companies and Organizations	Description of Companies and Organizations
Energy Companies	Utilities and companies that produce, supply and/or deliver energy
Technology-Engineering Companies	Firms that have a role in the deployment of IGCC technology, including plant construction and/or delivery of plant components.
Government Organizations	Experts who work for government agencies
Consulting Companies	Companies that provide information and data relevant to the IGCC industry.

3.3 Survey Results

Forty-eight (48) surveys were completed and returned. Some respondents answered only selected questions or indicated that they had "no opinion" regarding the significance of certain items. This result was expected given the wide range of items presented, and the diverse group of experts and stakeholders included in the sample. Further, many respondents provided written comments stating the bases for their answers.

3.3.1 Summary of the Most Significant Challenges

The initial analysis of the data focused on identifying the most significant challenges to IGCC deployment as ranked by the respondents--Top-Tier barriers with ranking scores of 4.00 or higher and Second-Tier barriers with ranking scores of 3.50 to 3.99.

As shown in Table 3.3, respondents ranked only four items at 4.00 or higher. Three of these are financial concerns--higher capital costs for IGCC power plants than for Natural Gas Combustion Turbines ("NGCTs") (mean score = 4.41), doubts about IGCC commercial viability without subsidies (mean score = 4.11), and increased risks associated with upfront development costs (mean score = 4.02). In addition, nine other financial items were ranked in the range of 3.50-3.99. The only non-financial item ranked at 4.00 or above was concern over low plant availability (mean score = 4.14).

Respondents identified 25 Second-Tier items with means scores of 3.50 to 3.99, including concerns regarding emissions regulation, lack of appreciation of IGCC benefits, past failures of IGCC, as well as a number of additional financial concerns regarding the availability of project finance, performance guarantees, and tax credits.

A detailed analysis of each category of items is presented in the following subsections. Tabulations and graphs of the survey results, as well as summaries of respondents' comments, are provided in Appendix B.

Table 3.3-- Summary of the Most Significant Barriers

Description of Top-Level Barriers *(based on ranking scores of 4.00 or greater)*	***Barrier Category***	***Mean***
1. Higher capital cost than NGCT	Financial	4.41
2. Chance of low plant availability	Technological	4.14
3. Doubts concerning commercial viability of IGCC (Doubts concerning the stand alone ability of IGCC to be competitive without subsidies)	Financial	4.11
4. Increased risk due to higher up front development costs (Front end engineering design costs are much higher for IGCC	Financial	4.02
Description of 2nd-Tier Barriers *(based on ranking scores of 3.50 or greater)*	***Barrier Category***	***Mean***
5. Skepticism regarding IGCC technology generally	Technological	3.91
6. Lack of turnkey vendors (EPC companies are unwilling to "wrap guarantees')	Financial	3.89
7. Problems with permitting process (Treating an IGCC facility as a natural gas plant instead of a coal plant with respect to air emissions permits)	Environmental	3.86
8. Failure of some IGCC projects	Cultural	3.86
9. Lack of certainty on regulation of emissions (Uncertainty regarding federal and state laws and regulations governing the following emmissions creates the prospect for substantial design modifications, protracted certification proceedings and increased capital costs)	Environmental	3.83
10.General lack of project finance	Financial	3.79
11. General economic downturn	Economic	3.79
12. Lack of regulatory stability and predictability (General uncertainty regarding critical rules including those governing electricity markets, power plant emissions, and power plant siting.)	Legal/Regulatory	3.74
13. Transition to competitive wholesale electric markets (with wholesale electric markets in a state of flux, power plant developers face uncertainty regarding future prices and market rules)	Legal/Regulatory	3.74
14. Lack of long term IGCC operating experience	Technological	3.73
15. Failure to socialize external benefit (Failure to reward investment for societal being realized through utilization of IGCC in the power industry, e.g.: lower emissions, stable electric costs, etc.)	Economic	3.73
16. Lack of adequate Power Purchase Agreements	Financial	3.72
17. Uncertainty of tax credits and qualification	Financial	3.72
18. Inability to guarantee performance (Weak licensor guarantees)	Financial	3.70
19. Lack of appreciation of need for fuel diversity	Cultural	3.69
20. History of problematic construction and slow start	Financial	3.67
21. Lack of appreciation for societal benefits	Cultural	3.67
22. CO_2	Environmental	3.65
23. Higher non-fuel operating cost than NGCT	Financial	3.63
24. Plant operators' lack of familiarity with IGCC (Distrust of chemical plants versus conventional boilers)	Cultural	3.62
25. Poor perception of coal- general public	Cultural	3.62
26. Lack of appreciation for energy independence	Cultural	3.61
27. General lack of developmental investment	Financial	3.58
28. Enron	Cultural	3.56
29. Long contruction lead times	Financial	3.53

3.3.2 Legal and Regulatory Challenges

The survey results indicate that the most significant challenges associated with legal and regulatory issues are:

- The lack of regulatory stability and predictability (mean score = 3.74)
- The current state of flux regarding wholesale prices and market rules (mean score = 3.74)
- Uncertainty regarding regulation of the generation sector (mean score = 3.46).

There was some consensus concerning these items since no respondent ranked any of them below 3.

These results underscore the need to adopt stable and predictable environmental regulations, and to establish definitive rules governing wholesale electricity markets--i.e., the Federal Energy Regulatory Commission's (FERC's) standard market design.

In addition to uncertainty regarding the regulation of generating plants, three items were viewed as mid-level concerns with means scores of 3.00 to 3.49. These included: the lack of a pre-approved design features, the degree of restructuring of retail electric markets, and uncertainty regarding wholesale transmission rules. There was a fairly even distribution of ranking scores for these items, indicating mixed perceptions among experts and stakeholders.

A number of items were viewed as having limited impact, including: the advent of demand-side programs, antitrust concerns related to the Public Utility Holding Company Act ("PUHCA"), and limitations on interconnection policies.

3.3.3 Environmental Challenges

There was considerable consensus regarding environmental challenges. The major concerns are:

- Problems with the permitting process (mean score =3.86)
- The lack of certainty on the regulation of emissions (mean score = 3.83)
- Carbon dioxide (mean score = 3.65)
- Mercury (mean score = 3.44)

In addition, four other environmental items were in the range of 3.00-3.39, and eight in the range of 2.50-2.99. None was ranked below 2.60. Further, only a small number of respondents indicated that they had "no opinion" on these matters.

These results show that environmental issues are a major challenge to IGCC deployment. Further, they indicate that a comprehensive environmental policy must be formulated to address a wide range of concerns about emissions, and that a piecemeal approach involving a series of individual retrofits meant to address single emissions regulations would not be efficacious.

3.3.4 Financial Challenges

Financial items were clearly viewed as being the most significant challenges to IGCC deployment. Three financial issues were ranked as Top-Tier items, with scores of 4.00 and above:

- Higher capital cost than NGCT (mean score = 4.41)
- Doubts regarding commercial availability of IGCC (mean score = 4.11)
- Increased risk due to higher up front development costs (mean score = 4.02)

Nearly two-thirds of the respondents ranked higher capital costs than NGCT as the single most significant challenge to IGCC deployment.

In addition to the three Top-Tier items, nine other financial concerns were ranked between 3.50 and 3.99. These included:

- Lack of turnkey vendors (mean score = 3.89)
- General lack of project finance (mean score = 3.79)
- Lack of adequate purchase power agreements (mean score = 3.72)
- Uncertainty of tax credits (mean score = 3.72)
- Inability to guarantee performance (mean score = 3.70)
- History of problematic construction and slow start (mean score = 3.67)
- Higher non-fuel operating costs than NGCT (mean score = 3.63)
- General lack of developmental investment (mean score = 3.58)
- Long construction lead times (mean score = 3.53)

There was consensus that financial items are the most critical challenges to IGCC deployment. Only a negligible percentage of survey respondents indicated that they had "no opinion" on these matters.

3.3.5 Economic Challenges

Two economic issues were ranked as Second-Tier items:

- Concern over the general economic downturn (mean score = 3.79)
- Failure to socialize external benefits (mean score = 3.73)

In addition, two other economic matters were ranked between 3.30 and 3.49:

- Volatility of natural gas prices (mean score = 3.48)
- Uncertain life cycle costs (mean score = 3.34

These results indicate that general economic concerns represent a significant challenge to IGCC deployment, but are not as critical as project-specific financial concerns such as the higher capital cost of IGCC relative to NGCTs (mean score = 4.42), doubts regarding commercial viability of IGCC (mean score = 4.17), and increased risk due to higher upfront development costs (mean score = 4.02).

3.3.6 Cultural Challenges

The most prominent cultural challenge is the history of failed IGCC projects (mean score = 3.86). Other significant cultural challenges include:

- Lack of appreciation for fuel diversity (mean score = 3.69)
- Lack of appreciation for social benefits (mean score = 3.67)
- Poor perception of coal in the general public (mean score = 3.63)
- Plant operators' lack of familiarity (mean score = 3.62)

These results highlight the need for educational programs to inform key stakeholders, power plant developers, the financial community, regulators and the general public about the benefits of producing electricity from IGCC facilities, the advances that have been made in this area, and the successful operation of IGCC power plants in the U.S.

3.3.7 Technological Challenges

The key technological challenge was the chance of low plant availability, which had a mean score of 4.14, making it the second most critical challenge overall in the survey results. Other significant concerns were skepticism regarding IGCC technology in general (mean score = 3.91), and the general lack of IGCC operating experience (mean score = 3.73).

On the other hand, specific technological concerns were not considered significant constraints. Items such as lack of syngas transport from the gasifier to another site, uncertain feedstock injection technology, skepticism regarding membrane air separation technology, and slow fuel cell development were ranked in the range of 2.19-2.59.

Based on these results, it appears that the technology *per se* is not the main challenge to expanded IGCC deployment. Rather, it is more general concerns regarding financing and the possibility of low plant availability that pose the most significant challenges to IGCC deployment.

3.4 Differences in Survey Results Among Respondent Groups

In addition to identifying and ranking the key challenges to IGCC deployment highlighted by the survey, an analysis was also conducted to determine whether, and to what extent, the various groups of participants responded differently to the survey items. This was done to identify issues where stakeholders generally agree and to ascertain areas of disagreement. Such information will be useful in formulating policies for overcoming critical challenges to the deployment of IGCC power plants.

Four different groups participated in the survey, as shown in Table 3.4.

Table 3.4 - Respondent Groups Completing Survey

Types of Respondent Groups	Completed Surveys
Government/Regulatory Organizations	12
Energy Companies	13
Technology/Engineering Companies	19
Consulting/Financial Companies	4
Total	48

The analysis was based on examining the mean ranking scores for each of the respondent groups, and comparing them with the overall aggregate scores. The results are not statistically significant given the small number of participants in the Consulting/Financial group. Nevertheless, this analysis provides a useful method of systematically determining the variation in perceptions across stakeholder groups.

The detailed mean ranking score results of the respective groups are provided in Appendix C. The discussion in this subsection summarizes those results.

3.4.1 Legal/Regulatory Challenges

Generally, the Legal/Regulatory survey results for the government/regulatory, energy company, and technology/engineering groups tracked each other fairly closely. The rankings indicated by the government/regulatory group for the lack of regulatory stability and uncertain state siting processes were somewhat lower than the aggregate mean scores. Conversely, the group's rankings for the lack of pre-approved design features were somewhat above the average.

The rankings given by the consultant/financial group differed markedly from those of other groups. This group ranked uncertainty regarding state siting processes much higher than the aggregate score (4.00 v. 2.86). The consultant/financial group also gave above average rankings to uncertainty regarding wholesale market rules, and limitations on capacity and co-production.

3.4.2 Environmental Challenges

As in the case of Legal/Regulatory items, the responses by the government/regulatory, energy company, and technology/engineering groups generally followed similar patterns. Nevertheless, there were several notable differences.

The government/regulatory group ranked the lack of certainty in regulating emissions slightly lower than the other groups. However, its rankings for regulation of particulates, Best Available Control Technology, and the use of hazardous and non-hazardous wastes to co-fire were well above the aggregate scores for these items. The energy companies indicated the general lack of certainty regarding regulation of emissions, as well as specific concerns with respect to carbon dioxide and mercury, as being high-ranking challenges (mean scores of 4.00-4.17). In contrast, other groups all ranked these items below 4.00.

The technology and engineering companies ranked permitting problems as a major concern (4.11), whereas the other groups all ranked this item below 4.00.

The consulting/financial group ranked many items considerably below the aggregate scores. Most notably, it ranked lack of certainty on regulation of emissions as 2.50, compared with the aggregate score of 3.83.

3.4.3 Financial Challenges

All of the groups regarded financial issues as the most significant challenge to IGCC deployment. Each group ranked higher capital costs for IGCC relative to NGCTs as the most significant challenge to IGCC deployment, with rankings for this item between 4.25 and 4.61. There was even closer agreement on another major challenge--doubts about the commercial viability of IGCC--with rankings all in the range of 4.00 to 4.18. On the other hand, there was considerable disagreement regarding the significance of a number of other items. However, the disagreements did not follow a consistent pattern--i.e., there was no group whose responses tracked those of another group.

The government/regulatory group ranked higher capital cost (versus natural gas-fired units), higher non-fuel operating costs, and the lack of a hydrogen economy as more significant challenges than did other respondents. Conversely, it downplayed such items as the lack of purchase power agreements, poor counterparty creditworthiness, lack of project finance, lack of turnkey vendors, and lack of performance guarantees compared with the rankings by the other groups.

The energy companies regarded the lack of turnkey vendors and the possible withdrawal of tax credits for IGCC plants as a more important challenge than did other groups, but downplayed the significance of long construction lead times. The technology/engineering group ranked the lack of purchase power agreements considerably higher than the aggregate score (4.40 v. 3.72). It also gave above average rankings to general lack of project finance, lack of developmental investment, long construction lead times, and poor counterparty creditworthiness.

The consulting/financial group's results differed markedly from the aggregate scores. It ranked several items considerably below the aggregate scores--e.g., higher non-fuel operating costs, lack of developmental investment, lack of turnkey vendors--and ranked several items considerably higher than the other groups--e.g., uncertainty regarding tax credits, inability to accelerate depreciation.

3.4.4 Economic Challenges

The results with respect to economic items showed limited differences in opinion across the respondent groups. In general, economic items were all viewed as being relatively significant challenges to IGCC expansion.

The government/regulatory group gave higher rankings to uncertain fuel costs, uncertain coal transportation costs, and failure to socialize external benefits than did other groups. Conversely, it gave lower rankings to lack of investor owned utility financial strength and the lack of baseload demand. The energy companies gave substantially lower rankings to several items including uncertain fuel costs and uncertain coal transportation costs. The technology/engineering group was the only one that ranked the country's economic downturn as a prominent issue (4.06). And the consulting/financial group gave a far above average ranking to uncertain fuel costs, and a far below average ranking to lack of baseload demand.

3.4.5 Cultural Challenges

There was general agreement across the groups on most important concerns including: lack of appreciation for the societal benefits from IGCC deployment; poor public perception of coal; lack of appreciation for fuel source diversity; and the failure of previous IGCC projects.

One notable difference was consulting/financial group's ranking of the Enron debacle at 4.67, far above the aggregate score of 3.56. Another large differential was the energy companies' ranking of the poor historical perception of IGCC at 4.08, whereas no other group ranked it above 3.32.

3.4.6 Technological Challenges

There were significant differences between the government/regulatory group results and the other groups. The government/regulatory group ranked nearly almost all technological items considerably higher than the aggregate results.

The rankings by the energy companies did not vary appreciably from the aggregate scores. They gave somewhat higher rankings to two Items--general skepticism toward IGCC technology and chance of low plant availability. The technology/engineering group gave somewhat lower rankings to technological items relative to the aggregate scores, particularly with respect to uncertain CO_2 sequestration and lack of hydrogen transport plans. Last, the consulting/financial group's responses generally tracked the aggregate scores, except for two items. They ranked general skepticism toward IGCC and skepticism regarding optimal gasifier technology considerably below the aggregate scores.

3.5 Summary

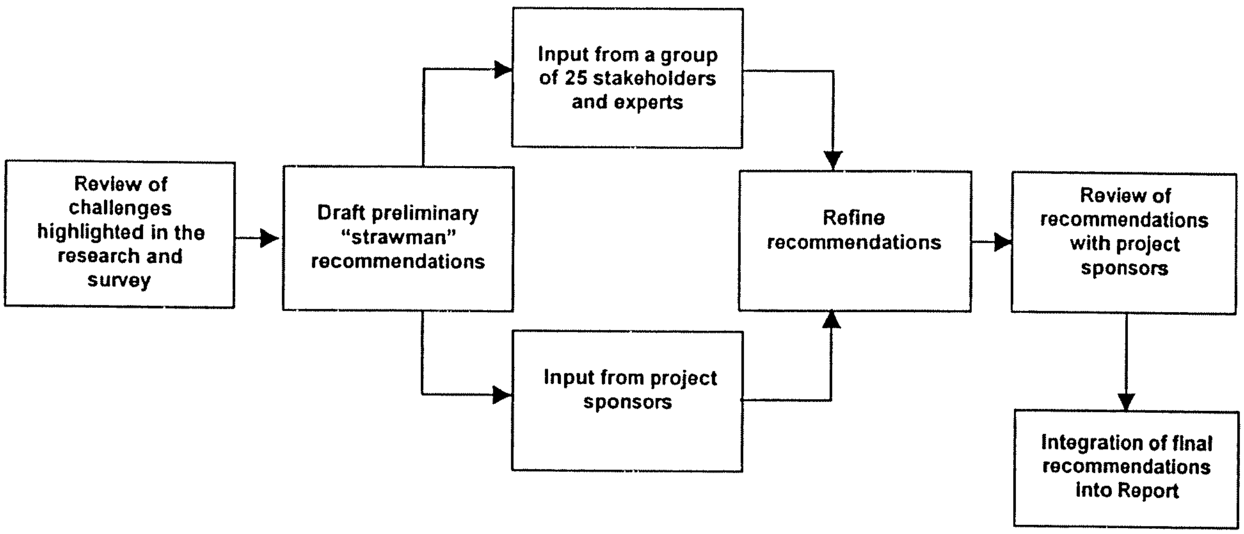
The survey results show that financial issues represent the most critical challenges to IGCC deployment. The areas of greatest concern include the relatively high capital cost of IGCC power plants and doubts about their commercial viability, along with one technical item--the chance of low plant availability. Other high-ranking challenges included siting and permitting problems for IGCC units and the lack of certainty regarding emissions regulations. Accordingly, these matters should be accorded the highest priority in formulating policies to facilitate the expanded utilization of IGCC power plants.

SECTION 4.
RECOMMENDATIONS

4.1 Approach For Developing the Recommendations

The process used to develop recommendations for expanding IGCC deployment presented in this Report is outlined in Figure 4-1 below. The starting point was an analysis of the challenges identified in the initial research and prioritized by the survey of stakeholders. A set of strawman recommendations was developed to address the key challenges highlighted in those processes. The recommendations were discussed with the project sponsors and other experts, and were revised in light of their comments. After a follow-up review, the recommendations were modified and outlined in this Report.

Figure 4.1 - Process for Developing Recommendations



In developing these recommendations, emphasis was placed on new institutional approaches rather than restructuring or modifying existing measures such as tax incentives and direct, project-based subsidies. It is critical to move forward with new initiatives, building upon what has been done to date and going beyond mere reconfiguration of long-established policies.

4.2 Detailed Discussion of the Factors Leading to the Recommendations

The recommendations for overcoming challenges to the deployment of IGCC power plants encompass six areas including: (1) Siting and Permitting; (2) Project Financing and Plant Availability; (3) Co-Production/National Security; (4) Strategies for Meeting Environmental Standards; (5) Relative Cost of IGCC Power Plants and Natural Gas Combustion Turbines; and (6) Federal and State Government Roles. The reasons for these recommendations are discussed in this subsection and the recommendations are outlined in Subsection 4.3.

4.2.1 Siting and Permitting

While a conventional coal-fueled power plant is permitted as one large facility with a well-known set of standards, an IGCC facility is currently subject to multiple permitting processes--i.e., it is treated as both a chemical plant and a power plant. Accordingly, the gasifier, the gas turbine, and the co-production unit operations (e.g., a sulfuric acid plant), among other elements of an IGCC facility, have to obtain separate and distinct operating permits. Consequently, a proposed IGCC facility will have to meet markedly different environmental standards than a single conventional coal-fueled generating unit that uses the same basic source of energy. As a result, IGCC projects are plainly at a disadvantage in the permitting process despite their environmental, economic and social advantages relative to conventional coal-fueled generating units. This situation discourages owners of coal-fueled power plants from repowering with IGCC technology and, in effect, encourages them to make incremental changes and retrofits.

To date, no regulatory agency has promulgated siting and permitting regulations specific to IGCC power plants. Such a result is not surprising since only a small number of IGCC plants have been permitted in the U.S. This is a chicken and egg problem. If specific requirements for an IGCC power plant are not established, it is unlikely that a significant number of these facilities will be deployed in light of the complicated permitting process and related regulatory and financial uncertainty.

The different permitting methodology for IGCC projects is most evident with respect to nitrogen oxide emission requirements. IGCC nitrogen oxide emissions are relatively low compared with those allowed for other coal-fueled plants.[89] Nevertheless, the permitting process has been based on the standards applicable to other gas turbine technologies. The Best Available Control Technology ("BACT") standard for natural gas combustion turbines is currently in the range of 2-4 ppm for nitrogen oxides, below the level that currently can be achieved by IGCC plants.[90] However, as discussed in Section 2.1.1.1, the BACT standard for natural gas combustion turbines is not appropriate for IGCC facilities.[91] Enhanced control technology would probably be needed if regulators required that IGCC facilities meet the BACT standards as applied to natural gas-fired combustion turbines. The current state-of-the-art control for syngas-fueled turbines utilizes diluents, such as nitrogen or steam, to reduce nitrogen oxide emission levels to approximately 15 ppm. This approach has been adopted in the final nitrogen oxide BACT determination for the Polk plant, and should serve as precedent in future permitting of IGCC power plants in lieu of standards based on natural gas-fired combustion turbines.

There are similar problems regarding certain byproducts of IGCC operations. Some jurisdictions treat these byproducts as solid wastes, thereby requiring them to meet applicable solid waste limits and failing to consider that many byproducts can be sold as commercially valuable materials.[92] Economic byproducts that can be sold into markets should receive regulatory exemptions from solid waste permitting requirements since no disposal is involved.

These problems underscore the need for a single uniform set of environmental permitting standards for IGCC power plants, or at least modified standards that better reflect their actual capabilities. Under current permitting rules, the EPA allows state, tribal or local entities to serve as the "lead agency" in permitting power plants. Under that standard, the lead agency can apply more stringent permitting standards than those required under federal law.[93] This

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[89] Nitrogen oxide emissions from an IGCC facility can be as low as 0.31 lb/MWh, compared with emissions of 1 to 1.3 lb/MWh from conventional coal-fueled boilers. NETL, *Coal Plays Key Role in Electric Power Generation*, Technical Facts 014, p. 65.

[90] Ratifia-Brown, et al., op. cit., p. ES-9.

[91] Id., p. 2-39.

[92] The Polk plant has been required to dispose of slag in a double-lined Class I landfill, although a less expensive Class III landfill would be adequate and the possible utilization of slag in a variety of applications may negate the need for long-term disposal. Id., p. ES-6.

[93] 40 CFR § 52.21, Ratifia-Brown, op. cit., p. ES-9.

situation exacerbates the problem of siting and permitting IGCC power plants. The federal requirements in this area are unclear.[94] With additional overlaying state, tribal and local requirements, there is considerable uncertainty as to how the overall permitting requirements will be handled. To address this challenge, an initiative could be undertaken to develop multi-state Memoranda of Understanding specifying compatible and transparent standards for plant permitting.[95]

Another problem in siting and permitting IGCC power plants concerns the rules governing alternative "feedstock," or fuels. One of the major benefits of IGCC technology is that the same plant can be designed to operate with a number of different fuels including municipal solid waste, biomass, organic agricultural waste, petcoke, used tires, and plastics, among others. However, the EPA's rules are unclear with regard to the use of multiple fuels--called "co-firing"--as opposed to using only coal, and states do not have formal rules governing co-firing.[96] This problem arises principally because the applicable regulations were developed to govern the siting and permitting process for combustion-based units that have very little flexibility with respect to feedstocks compared to IGCC technologies. The failure of the permitting process to consider the flexibility of IGCC units in utilizing multiple feedstocks imposes another significant challenge to the commercialization and deployment of this technology.

For example, if less than 30% of the fuel consumed in an IGCC unit is derived from municipal solid waste, the facility must be permitted as a coal-fueled plant. Conversely, if more than 30% of the fuel is derived from municipal solid waste, the unit is not treated as a coal-fueled plant.[97] Depending on which type of permit is needed, there are different requirements for emissions, material handling, and operator training, among others. However, the emissions produced by using the different feedstocks are relatively similar. Under current permitting rules, it is conceivable that an IGCC power plant may have to obtain multiple permits in order to realize the benefit of feedstock flexibility or pass up economic opportunities where the fuel mix may vary beyond the plant's permit. Such a result is uneconomic, discourages the use of the most economic and beneficial fuels, and would preclude ratepayers from realizing the significant reductions in their electricity charges.

In view of these and other considerations, it would be useful for the federal and state governments to immediately initiate an effort to develop a single set of standards for the siting and permitting of IGCC power plants. As a result, the same requirements would be applied to all IGCC facilities with respect to BACT standards, the treatment of salable byproducts, co-production, and flexibility in the mix of coal and other feedstocks, among others.

4.2.2 Project Financing and Plant Availability

According to the survey of experts and stakeholders, the lack of adequate developmental and project financing has been a major challenge to deployment of IGCC power plants. The significant underlying causes include: (1) the perceived low rate of availability at IGCC projects in the early years of operation resulting in substantially lower net present values (NPVs) for that period; (2) the uncertain capital funding needs of IGCC projects; (3) the lack of guarantees for the overall performance of the IGCC power units by plant designers, equipment suppliers, and

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[94] See e.g., Supplemental Technical Comments of Allen County Citizens for the Environment Concerning a Proposed Prevention of Significant Deterioration Permit for the Global Energy IGCC Power Plant, Lima, OH, December 17, 2001, http://www.sagady.com/workproduct/GlobalEnergyLimaPlant.pdf
[95] This type of arrangement would be analogous to regional water resource agreements.
[96] Ratafia-Brown, et al, p. 3-26.
[97] Id. p.3-24

construction companies; and (4) the perceived need to finance IGCC power plants with government subsidies.

The purpose of this Report is not to recommend additional forms of direct subsidies or tax incentives. Rather, the actions proposed here are aimed at overcoming challenges that are not addressed through such existing measures. These recommendations are intended to produce institutional change that will permit IGCC technology to be deployed on the strength of its inherent advantages, and its benefits to the U.S. economy and society in general.

The basic institutional problem of IGCC project financing is that the logical participants--developers, architect/engineering ("A&E") firms, electric utilities, construction companies, project finance providers, fuel suppliers, byproduct purchasers, municipal waste handlers, among others--are unwilling to take significant risks with this technology, notwithstanding the enormous benefits of its successful deployment to both individual participants and the general economy. Consequently, initiatives to expand the deployment of IGCC power plants should be focused on facilitating and supporting participation by those entities.

Further, as discussed in Section 3, the survey results indicated that the low availability rate of IGCC facilities in their early stages of operations is a major challenge to their expanded deployment. Nevertheless, IGCC units such as the Polk and Wabash River plants have performed very well after an initial "shakeout" period.[98] They have achieved availability rates of approximately 80% and 75%, respectively, in recent years, and are approaching the 85% target availability factor for IGCC.

The low early availability rates at Polk and Wabash River were primarily attributable to unique overall design challenges, equipment and inter-component design problems, general operating problems, and general inexperience with IGCC technology. Different components such as the air separation unit, gasifier, co-production facilities, gas turbines, and sulfuric acid production units must generally be acquired from multiple manufacturers, thereby complicating procurement and project management functions. Moreover, all of these separate components must work together seamlessly to achieve high early availability levels. Early availability should become less of a problem as the industry becomes more familiar with IGCC technology.

Accordingly, during the transition period in which more extensive experience with IGCC facilities is developed, measures could be implemented to address the risk of poor performance in the early stages of operation. Such measures would significantly improve the prospects of financing IGCC projects.

In view of these circumstances, a federally sponsored program similar to the Overseas Private Investment Corporation ("OPIC")[99] could be developed. The OPIC insures eligible U.S. privately funded projects in developing countries and emerging markets against risks such as currency inconvertibility, expropriation, and political violence. Special OPIC programs address such matters as: (1) letters of credit; (2) petroleum exploration, development and production; (3) leasing operations; and (4) debt financings, including securities.

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[98] See http://www.lanl.gov/projects/cctc/factsheets/wabsh/wabashrdemo.html; http://www.lanl.gov/projects/cctc/factsheets/tampa/documents/tampa.pdf.

[99] Foreign Assistance Act of 1969, Title IV, Section 234(a), Public Law 91-175, 22 U.S.C. 2191, et seq.

The OPIC has been very successful in a number of ways.[100] The program is self-sustaining. Over the past 30 years, it has supported more than $142 billion in U.S. overseas investments that will generate $64 billion in U.S. exports and create more than 253,000 American jobs. In 2001, OPIC had a net income of $215 million. Additionally, OPIC has benefited the 140 countries in which it has operated or is currently operating, supporting sustained development and international trade while solidifying free markets. Projects insured or financed in 2001 alone are expected to create nearly 5,562 direct jobs in developing and emerging markets, while generating $200 million in host government revenues.

The program recommended here for rapid IGCC commercialization and deployment--the federal "IGCC Availability Assurance Program"--would establish an insurance fund similar to OPIC that would be paid to developers of IGCC facilities in the event of availability problems in the early stages of plant operations. Developers would pay a premium to the fund for the insurance, with federal guarantees protecting against a portion of the risk. The need for federal guarantees would diminish and probably be eliminated as IGCC technology is commercialized further and plant designs are standardized.

The fund could also be supplemented by a general "uplift charge"[101] applied by a Transmission Service Provider (TSP) such as a Regional Transmission Organization (RTO) or Independent System Operator (ISO).[102] This charge would be similar to the "system benefits charges" that are incorporated in utility bills by many state Public Utility Commissions (PUCs) to provide a number of public benefits, including programs for low-income customers and load control, among others. The uplift charges would be offset by the benefits of having IGCC facilities on the TSP's system that produce lower wholesale electricity prices for all consumers, and reduce airborne emissions and solid wastes. The economic benefits of lower wholesale prices could be monetized and allocated to the IGCC Availability Assurance Program, thereby reducing, and ultimately eliminating direct federal funding needed to support the initiative.

Further, a fund could be established to partially protect developers against capital cost overruns for IGCC plants. One very significant challenge is that developers are exposed to considerable uncertainty regarding IGCC capital cost requirements, making it very difficult if not impossible to finance a project without direct subsidies. While DOE research has estimated that IGCC capital costs should be on the order of $1,200 per KW,[103] it has been reported that the capital costs of the Polk Plant were between $1,650 and $2,430 per KW, depending on whether costs for site acquisition and development, construction management, startup, operator training, project management, permitting and preliminary engineering are included.[104] Utilities and the financial community are not in a position to accept the risk that the next generation of IGCC power plants could involve capital costs of that magnitude. Under the proposed program, there could be a sharing of excess costs between the developer and the federal government if capital costs exceeded a certain target--e.g., $1,200 per KW (DOE's projection for IGCC power plants based on economies-of-scale). This sharing mechanism would reduce the exposure of developers to cost overruns without unduly weakening their incentive to hold down project costs. The funds required to support this program could also be wholly or partially recovered through payment of insurance premiums by developers and a general TSP uplift charge. As with the proposed

[100] See http://www.opic.gov.

[101] An uplift charge is a charge imposed by the Transmission Service Provider on all customers and users of the system. It is typically applied on the basis of peak load requirements--i.e., the customer's "load share ratio."

[102] FERC has authorized several ISOs and RTO, and is considering new rules governing such entities in its proceeding on Standard Market Design Docket No. RM01-12-000).

[103] NETL, *Coal Plays Key Role in Electric Power Generation*, Technical Facts 014, p. 65.

[104] Smith, *IGCC Technology Continues to Develop, Power Engineering*, November 2003.

Availability Assurance Program, the need for this type of program will diminish as experience is gained with the construction and operation of IGCC power plants.

Another area that should be addressed is the problem of equipment and technology procurement. Currently, developers must undertake an extensive and difficult procurement program in order to obtain the equipment and services needed to build and operate an IGCC power plant. There is no single procurement source for the wide range of technology and equipment required to permit and construct an IGCC power plant. A program could be developed to assist in this endeavor.

4.2.3 Co-Production and National Security

IGCC technology is ideally suited to the co-production of transportation fuels. In addition, many other useful fuels, including methanol, naphtha and others, can be produced along with electricity in IGCC facilities. The national security advantage of being able to convert our largest domestic energy resource--coal--into liquid hydrocarbon/transportation fuels and chemicals that can decrease dependence on foreign nations is a major benefit of IGCC deployment. Another advantage is that the fuels produced by IGCC co-production are free of sulfur and a variety of other environmentally sensitive contaminants. Accordingly, these fuels will already meet upcoming EPA transportation fuel standards. As discussed in Section 2.4.1 of this Report, it has been estimated that 20 GW of IGCC generation capacity with co-production capabilities could produce output sufficient to displace approximately 14% of the "on highway" diesel fuels consumed in the U.S.

In view of these considerations, a study could be conducted on the economics of using IGCC facilities to co-produce electricity and liquid fuels, such as transportation fuels, on an economic dispatch basis. Since high capital costs are a significant challenge to commercialization and deployment of IGCC technology, any mode of operation that increases revenues will increase the likelihood obtaining project finance. Under an economic dispatch mode of operation, an IGCC plant could be used for power production when the price of electricity is high (e.g., during the day). Conversely, when electricity prices are low, the plant could produce transportation fuels and other outputs, such as methanol,[105] that can be employed as a substitute fuel in many natural gas combustion turbines. Using methanol as a substitute for natural gas could, to some extent, ease the economic impact of continued increases in natural gas consumption by electric generators.

Because the generation block in an IGCC facility is a combined cycle gas turbine, the ramp-up time for electricity production is relatively short compared to most coal-fueled technologies. This also would allow for the sale of ancillary services, such as spinning reserves, when producing transportation fuels resulting in an additional revenue stream. However, it is not clear how quickly the fuel production capabilities could be ramped up or down. As discussed in Section 1.3.1, the Wabash Plant operates not only as a baseload unit but also as a load following facility, indicating significant flexibility in ramping power generation up and down. This factor should be considered in the study of co-production economics, including the sale of ancillary

[105] Methanol is an attractive future fuel for stationary gas turbine engines. GE tests have shown that, with minor system modifications, methanol is readily fired and is fully feasible as a natural gas turbine fuel. Relative to natural gas and distillate, methanol can achieve an improved heat rate and higher power due to higher mass flow, and reduced nitrogen oxide emissions due to lower flame temperature. (Reference: GE position paper, "Feasibility of Methanol as Gas Turbine Fuel," http:/www.methanol.org/GEWhitePaper.pdf.

services, in order to optimize the output and revenues of IGCC facilities employing co-production.

4.2.4 Strategies for Meeting Environmental Standards

The deployment of IGCC technology is hindered by uncertainty regarding future regulations, the piecemeal approach of the electric industry and regulators to meeting future environmental standards, and the absence of efficient markets in which the forward value of emissions and effluent reductions can be valued and monetized. As result, determinations regarding the choice of technology for new generating facilities and for repowering of existing plants cannot be made on a sound economic basis. Accordingly, the value of emissions and effluent reductions cannot be recognized as an offset to the capital costs of IGCC technology--which survey respondents identified as a critical challenge to IGCC deployment.

An important benefit of IGCC technology is that it substantially reduces many of the emissions and effluents that would be produced by the continued operation of older, conventional coal-fueled power plants (if not retrofitted with appropriate control technologies). Repowering such plants with IGCC technology would provide an opportunity to solve a number of existing issues that may otherwise be addressed in a piecemeal and uneconomic manner. Using IGCC technology in new facilities could also substantially mitigate further emissions reduction expenditures going forward.

However, it is very difficult to accurately assess the economic and financial value of adopting IGCC technology for this purpose in light of the uncertainty regarding future regulation of power plant emissions. While nitrogen oxides, sulfur dioxide and particulates are currently regulated, the value of reducing these emissions in the future is uncertain. Further, whether and to what extent greenhouse gases including carbon dioxide will be regulated is unclear. There is also uncertainty as to how mercury will be regulated, with the EPA having announced proposed rules in December 2003. Moreover, as discussed below, legislation has been proposed to modify these requirements, thereby adding to the uncertainty.

These circumstances serve to encourage piecemeal approaches to emissions reductions that impede the development of comprehensive long-term, least-cost solutions. A series of projects that each reduces a single pollutant may be considerably more costly in the long run than meeting pending and reasonably anticipated emissions requirements with IGCC technology in one step. Moreover, as piecemeal investments in single pollutant fixes proceed, the efficacy of a comprehensive approach is diminished and such a strategy may be rendered uneconomic.[106]

Nevertheless, it is essential to anticipate future trends in environmental regulation at this time, and factor those assumptions into upcoming decisions regarding selection of power plant technology since those determinations will be tantamount to a "40 year" choice. Accordingly, such decisions should be based on assumptions that all of the emissions discussed herein--including nitrogen oxides, sulfur dioxide, particulates, greenhouse gases, and mercury--will be regulated at some future date, and that markets for trading reductions in these emissions will

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[106] This can be seen in comparing the hypothetical choice between Scenario 1, a piecemeal approach involving a series of five investments costing $120 million per project, which are each designed to meet one objective, and Scenario 2, a comprehensive project costing $500 million, which meets all of the objectives. At the outset, Scenario 2 is obviously more cost-effective since it entails $100 million less in total expenditures. However, after the initial investment is made in Scenario 1 to meet the first objective, that Scenario becomes the more economical since it will cost $480 million going forward to meet Objectives 2 through 5, compared with the $500 million cost of Scenario 2. The net result, however, will be $100 million of excess and unnecessary expenditures.

exist, thereby providing revenue streams that will mitigate near-term capital costs. Consequently, efforts could be made to develop comprehensive plans for meeting existing and anticipated emissions reduction requirements rather than addressing them at one time with resulting inefficient use of capital and other resources.

Subsections 4.2.4.1 through 4.2.4.5 discuss key issues concerning the various emissions, and Subsection 4.2.4.6 outlines a comprehensive, forward-looking approach for meeting anticipated emissions requirements.

4.2.4.1 Nitrogen Oxides and Sulfur Oxides

Under current law, a power plant is awarded a certain number of allowances for nitrogen oxides and sulfur oxides based on current performance. The allowances can be used to cover emissions of these pollutants. If the emissions are reduced, the allowances can be sold or "banked" for future sale or use. The federal government has established markets for these credits, and those markets are generally considered to be very effective.

At this time, there are markets for trading nitrogen oxide allowances allocated to existing power plant emission sources. An allowance for the emission of one ton of nitrogen oxide peaked at about $7,000 in 1999 and is now worth about $2,500-$3,000. However, the future value of this revenue source is not fully available to developers of an IGCC facility. Nitrogen oxide emissions can be greatly reduced compared to those of an existing conventional coal-fueled plant if the facility is repowered using IGCC technology. However, while repowering a conventional plant entitles the developer to retain a number of allowances that can be sold, the forward market for these allowances extends only through the 2007-08 timeframe. The liquidity of the out-year markets is therefore uncertain. Consequently, a developer seeking to repower older conventional plants with IGCC technology cannot use the value of nitrogen oxide credits to offset capital costs. Conversely, if those credits were available on a forward basis, they could be utilized for that purpose.

To put this in perspective, an IGCC plant emits approximately one pound per MWh less nitrogen oxides than a conventional coal-fueled power plant.[107] Over a 20-year period, a 500 MW IGCC or conventional plant will generate approximately 70 million MWh.[108] Repowering a conventional coal-fueled power plant using IGCC technology would reduce nitrogen oxide emissions during that 20-year period by about 35,000 tons. At $2,500 per ton, this would produce a forward allowance value of $87.5 million--about $43.8 million after discounting by 50%. If these assets could be realized during project finance, they would reduce the capital cost of IGCC repowering a 500 MW plant from approximately $600 million to $556.2 million--a decrease of 7.3%.[109]

To ensure determinations regarding the possible repowering of conventional coal-fueled plants are made on a sound economic basis, the value of future nitrogen oxide credits could be factored into the decision-making process. Accordingly, developers of such projects could be credited with emissions allowances equivalent to the overall reduction of these emissions over the plant's operating life--e.g., 40 years. While it may not make sense to sell these credits into a

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[107] NETL, *Coal Plays Key Role in Electric Power Generation*, Technical Facts 014, p. 65.
[108] Assumes 500MW and 80% availability.
[109] At $1,200 per KW, the capital cost of repowering a 500MW plant would be approximately $600 million. If $43.8 million were deducted from this amount, the capital cost of the project would decrease to $556.2 million. The calculations presented here are intended to indicate the order of magnitude of potential forward financial benefits. The overall cost of one-time repowering with IGCC technology versus incremental retrofits should be analyzed in a rigorous study.

market with limited liquidity, the developer or financier would certainly have the opportunity to bank these credits for future use or sale. This would be especially true if the accounting profession developed a standard for recognizing those assets so that they could be reported in financial statements filed with the Securities and Exchange Commission and used by state regulators in their regulatory activities. Those assets, even if valued conservatively, could significantly enhance the balance sheet of any brownfield conventional-to-IGCC repowering, and thereby improve the prospects of financing the project.

4.2.4.2 Mercury

The EPA is in the process of promulgating rules governing the emission of mercury from coal-fired power plants. Pursuant to a settlement of Clear Air Act litigation and a subsequent finding that mercury emissions are hazardous air pollutants requiring regulation under the Clean Air Act, the EPA proposed new rules concerning this matter on December 15, 2003.[110] Two alternatives were put forward. One approach would require coal-fired power plants to install currently available maximum achievable control technologies (MACT) for mercury. According to the EPA, this would reduce nationwide mercury emissions from an estimated 48 tons a year to 34 tons a year--a decrease of 29% by 2007. The second approach would set a mandatory, declining cap on total mercury emissions from coal-burning power plants nationwide. This approach, which would allow emissions trading, would reduce mercury emissions by nearly 70% from current levels once the final mercury cap takes effect in 2018.[111]

Environmental advocacy groups and some elected officials and state regulators are likely to challenge the proposed rules. They have contended that the MACT standard mandates a reduction of approximately 90% in power plant mercury emissions, noting that commercial methods used for many years to remove trace amounts of mercury from natural gas and gasifier syngas can achieve 90% to 95% removal efficiency and that several states have concluded that this level of reductions is achievable.[112] Further, environmental advocacy groups maintain that a cap-and-trade approach is inappropriate for controlling mercury emissions since it could allow "hot spots" of mercury contamination in lakes and rivers neighboring plants that buy pollution credits instead of reducing their mercury emissions.

Mercury emissions standards could also be affected by Clear Skies legislation that was proposed by the Administration in February 2002. Clear Skies would modify the Clean Air Act's requirements regarding a number of pollutants, including mercury. It would create a mandatory program that would reduce power plant emissions of sulfur oxides, nitrogen oxides and mercury by setting a national cap on each pollutant. It would also establish a cap-and-trade market for

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[110] The settlement reached in 1998 required the EPA to make a determination by December 15, 2000 as to whether the regulation of mercury emissions was power plants was "necessary and appropriate." National Resource Defense Council v. U.S. Environmental Protection Agency, U.S. Court of Appeals (D.C. Circuit.), Docket No. 92-1415, Stipulation for Modification of Settlement Agreement, filed November 1998. The EPA issued such a finding on December 20, 2000. 655 Fed. Reg. 79,825. Having made that finding, the EPA was then obligated under the terms of the settlement to issue a notice of proposed rulemaking by December 15, 2003.

[111] EPA Fact Sheet, December 15, 2003, http://www.epa.gov/mercury/mercuryfact12-15final.pdf. and U.S. Environmental Protection Agency, Headquarters Press Release, Washington, DC, For Release, 12/15/2003, *Clean Air Proposals Promise Sharp Power Plant Pollution Reductions* , see http://yosemite.epa.gov/opa/admpress.nsf/b1ab9f485b098972852562e7004dc686/b8860b2d46c43fa385256dfd007870df?OpenDocument

[112] See e.g., http://www.nescaum.org/newsroom/pr031104mercury.pdf; http://epw.senate.gov/108th/Jeffords_050803_3.htm; www.nrdc.org/media/pressrreleases/031205.asp.

mercury. Mercury emissions would be reduced from 48 tons in 1999 to a cap of 26 tons in 2010 (a reduction of about 46%), and to a cap of 15 tons in 2018 (a reduction of about 69%).

IGCC technology would be highly cost-effective in reducing mercury emissions compared with conventional coal-fired units. It has been estimated that the incremental cost of mercury reduction in an IGCC power plant is $3,412 per pound of mercury, approximately one-tenth the cost of flue gas-based mercury control, assuming a 90% reduction of mercury.[113] Thus, the incremental cost of mercury reduction for a 500 MW IGCC repowering project would be approximately 25 cents per MWh. In contrast, the incremental cost of operating a 500 MW retrofitted conventional coal-fueled generating plant to achieve 90% mercury removal would be approximately $3.10 per MWh. This differential would produce savings of approximately $10 million per year. Over a 20-year period, the savings would amount to almost $200 million.[114] Discounting that amount by 50%, the net saving would be approximately $100 million.

The savings from IGCC repowering related to lower cost mercury control would be smaller to the extent that mercury reduction requirements were less than 90%. Nevertheless, those savings still could be significant and could provide an important revenue source for a project developer. Those savings would be in addition to the savings realized from nitrogen oxide reduction credits discussed in Section 4.2.4.1.

The calculations presented here are approximations of the savings that could be achieved through the utilization of IGCC technology. A detailed examination of those savings should be undertaken to ascertain their likely value to project developers.

As in the case of nitrogen oxides, the discounted future value of mercury emissions reductions expenditures should be considered in determining the technology used to meet anticipated generation requirements. Developers could be granted or otherwise acquire all or most of the allowances equivalent to the overall reduction of these emissions throughout the lifetime of the plant's operation--e.g., 40 years.

4.2.4.3 Carbon Dioxide

Another institutional problem for IGCC developers is their inability to benefit from reductions in carbon dioxide emissions. These emissions are the principal contributor to greenhouse gases ("GHGs") that are believed to produce global warming. Because IGCC facilities are more efficient than conventional coal-fueled plants, they emit significantly less carbon dioxide. Moreover, if sequestration technologies are successfully commercialized, carbon dioxide emissions from IGCC facilities could largely be eliminated. While there has been some limited bilateral trading of carbon dioxide emissions reductions, there is no formal mechanism for recognizing their current or future value.[115]

A voluntary federal program for reporting voluntary measures to reduce, avoid, or sequester GHG emissions was established under § 1605 (b) of the Energy Policy Act of 1992. The program, which is administered by the Energy Information Agency (EIA), serves a useful educational function by highlighting voluntary emissions reduction efforts that have been

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[113] Ratifia-Brown, op. cit., p. ES-5.

[114] A 500 MW plant operating at 80% availability would produce approximately 3.5 million MWh per year. The incremental differential between retrofit and repowering to remove mercury is approximately $2.85 per MWh or approximately $10 million per year.

[115] Peter Fusaro, *Greentrading(tm): The Next Financial Market*, International Research Center for Energy and Economic Development, University of Colorado, 2003

undertaken to date.[116] However, the program does not provide a systematic, comprehensive protocol for recording and verifying emissions reductions. Further, a number of states and regions have established GHG reduction programs. While there has been some limited coordination, most of these programs have been developed independently.[117] As a result, the state and regional registries are not uniform and therefore cannot provide a "common currency" in GHG reductions.

Building upon the existing EIA reporting program, a strong federal GHG registry, with effective measurement and verification standards, could be created to support the U.S. policy of promoting voluntary GHG emissions reduction. That strong federal registry could be supplemented by state and/or regional registries that utilized the same standards.[118] These registries would facilitate active bilateral trading in voluntary GHG reductions and also allow entities to bank reduction credits for future use. The availability of such trading opportunities could provide an important means of financing IGCC projects, particularly repowering of older coal-fueled plants that substantially reduce GHGs. The registries would not have to determine a price or value for carbon dioxide reduction credits. Instead, they would set standards for measurement and verification as well as transfer of title. The administrative costs of the registries could be paid for by the entities seeking to record their GHG reductions through membership fees, so that any costs to taxpayers could be defrayed or completely eliminated.

A strong federal GHG registry and/or uniform state GHG registries could be made compatible with the GHG registries that are being developed by other nations, and with trading markets that are being created in the U.S. and abroad. Ideally, it should be possible in the future to use GHG reductions recorded in U.S. registries to meet the needs of Kyoto Treaty signatory nations or any type of emissions trading that occurs in place of Kyoto Treaty if it does not go into effect internationally. The European Union (EU) in early July 2003 announced its intention to establish an Emission Trading Scheme (ETS).[119] It plans to integrate the Kyoto Treaty requirements with its ETS to ensure compliance with the Treaty and at the same time allow for uniform trading of GHG emissions reduction credits. The scheme as announced addresses many of the concerns that have been raised in regard to the possible establishment of a strong federal registry, and uniform state and regional registries. These concerns include double-counting, limiting reduction and offset credits to "real" projects, eliminating free riders, and legitimately converting EU's credits to Kyoto Treaty credits, among others. As a result, there is a large body of work that could be used to assure that any U.S. registries will be compatible with the EU system. The U.S. could work with the EU ETS to achieve this objective.

Private U.S. exchanges are beginning to form as well. The Chicago Climate Exchange (CCX) recently began trading of GHG emissions. The first auction of CCX emission allowances was held on October 1, 2003, and continuous electronic trading of GHG emission allowances and offsets has been conducted since then.

[116] EIA, Voluntary Reporting of Greenhouse Gases 2000, February 2002, http://tonto.eia.doe.gov/FTPROOT/environment/0608(00), pdf p. 1-2.

[117] Reid Harvey, Overview of U.S. State-Level GHG Programs, USEPA, Clean Air Market Programs, December 4, 2002, http://www.ieta.org/About_IETA/IETA_Activities/AnnualConference_2002/Reid_Harvey_US_state_GHG_programs.pdf

[118] Alternatively, in the event a strong federal registry is not available, state and/or regional registries could provide a second-best mechanism for supporting bilateral trades of GHG emissions reductions.

[119] On July 2, 2003, the European Parliament voted on amendments to the draft EU Directive on emissions trading, thus facilitating its early adoption.

In the interim, until registries and markets for trading GHG emissions reductions are well established, a mechanism could be created to recognize and monetize the value of future reductions. This is necessary to ensure that the projected value of those reductions is factored into decisions concerning the technology used new generating facilities and repowering projects. For example, recent research has shown that if an IGCC power plant is initially designed to capture all carbon dioxide emissions, the ultimate cost of the capturing function would be significantly lower than if retrofitting was later required to provide that capability.[120] It would be useful for the states to develop tools for using credits in acceptable registries in their regulatory activities. Such considerations should be taken into account in choice of technology determinations.

4.2.4.4 Particulates

In 1997, the EPA passed new, stricter regulations to govern particulate emissions. In 1999 new EPA regulations set a standard for PM 2.5 (fine particulates 2.5 microns in diameter or less), and retained the former standard for PM10 (coarse particulates 10 microns or less). The move to regulate PM 2.5 may have a serious impact on the ability of some conventional coal-fueled plants to comply in the future. A nationwide system of monitors was established in 1999 to gather emissions data for three years. The US EPA is scheduled to decide by December 2004 which areas to declare non-attainment. After that states in non-attainment areas will develop State Implementation Plans to bring the air into compliance.[121] If a conventional coal-fueled power plant is operating within a non-attainment area, repowering a conventional plant with IGCC technology can effectively address the problem and assist in achieving attainment status. An economic, market-based solution should be considered with respect to particulate matters as well.

4.2.4.5 Other Environmental Considerations

In addition to reducing emissions of nitrogen oxides, sulfur dioxide, carbon dioxide, mercury, and particulates, IGCC power plants can provide other environmental benefits such as their ability to use municipal solid waste and animal wastes for electricity production. These benefits could be taken into account in the siting and permitting process as a unique power plant, and could also be reflected in renewable credits where they can be awarded.

State regulators have also suggested that the issue of improved water quality that results form the gasification of animal wastes should be studied. Water quality credits are being considered in several jurisdictions where animal wastes are major contributors to deteriorating water quality. The use of animal wastes as a feedstock and the resulting water quality improvements may also add to the forward economic value of IGCC technology.

4.2.4.6 Developing Forward-Looking Environmental Strategies

A market-based solution is essential to ensure that decisions regarding the means of meeting environmental standards are based on sound economic and policy principles. The alternative is to leave a command and control system in place, setting the stage for a repeat of the seemingly endless litigation surrounding New Source Review requirements in the case of each individual emission. This could perpetuate the current state of limbo in which the enormous environmental benefits of IGCC technology in the U.S. power sector cannot be quantified and factored into

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[120] Rutkowski <u>et al.</u>, <u>op.cit.</u>

[121] Indiana Department of Environmental Management, *Annual State of the Environment Report*, 2003

crucial energy planning determinations. As discussed in Subsection 4.2.4.1, the current piecemeal approach to resolving emissions requirements one pollutant at a time will ultimately be very cost-ineffective and a waste of significant resources.

In view of these considerations, it is essential to establish a comprehensive, forward-looking approach to meeting environmental standards. The measures include:

(1) Developing an overall projection of future emissions policies and establishing probabilistic ranges that can be used to calculate the probable value of emissions reductions over a 40 year period;

(2) Monetizing or valuing those future credits through funding financed by uplift social benefit charges applied by a Transmission Service Provider (TSP), Regional Transmission Organization (RTO) or Independent System Operator (ISO), with ongoing true-ups reconciling actual and projected credits; and

(3) Having the EPA enter into negotiations with the owners of older conventional coal-fueled power plants to assist in assessing the efficacy of coming into full compliance with air emissions requirements (present and future) by repowering with IGCC technology, with the monetization or recognition of future emissions credits and the avoidance of potential retrofits factored into those analyses. Where appropriate, consideration could be given to concluding long-term settlements that incorporate such provisions.

4.2.5 Relative Cost of IGCC Power Plants and Natural Gas Combustion Turbines

4.2.5.1 Over-Reliance on Natural Gas for Electricity Generation

Natural gas is a vital domestic resource. It is the one domestically produced fuel that can be utilized without substantial environmental impacts, except for carbon dioxide emissions. It is critical to meeting the nation's energy needs in the future.

In recent years, the vast majority of new electric generating plants have been natural gas-fired combined cycle gas turbines. In some places, most notably urban areas, many simple cycle, quick start gas turbines have also been installed to shore up inadequate generation capacity.[122] These uses of natural gas are inconsistent with the development of a sound long-term national energy policy.

Natural gas is a direct feedstock for many important domestic industrial processes, and is utilized in other important direct applications including residential heating. Consequently, in the long run, consuming natural gas for electric generation will reduce the amount of this critical resource that will be available for these essential purposes.

Moreover, the use of natural gas for electricity production is a key factor in the shortfalls in natural gas supplies that are have been experienced recently and in the run-up in natural gas prices. Forecasters are projecting that wholesale natural gas prices are likely to remain in the average range of $5 to $6 per MMBtu for the remainder of the decade. These prices are more than 30% above the average price of $3.87 per MMBtu that prevailed in 2000 and 2001. Such

[122] For example, in New York City, the New York Power Authority has installed ten small, simple cycle generators to meet peak summer demands. These peaker units are very inefficient because they do not use waste heat in the generation process. Further, they produce significant emissions when they do operate.

price increases substantially raise the cost of living for households throughout the nation and the cost of doing business in the industrial and commercial sectors, thereby creating inflationary pressures and dampening long-term economic growth. These effects are not likely to abate over time. Low cost natural gas supplies are being depleted rapidly, and pressure on supplies and prices will increase as the economy expands.

The use of natural gas for electricity production also has important national security implications. At today's consumption level, U.S. proven natural gas reserves are far smaller than its coal reserves. According to the Energy Information Agency, the U.S. has approximately 183 trillion cubic feet of proven natural gas reserves and annual consumption of approximately 20 trillion cubic feet.[123] Consequently, the proven reserves can meet only about 10 years of consumption. In contrast, U.S. coal reserves can meet current consumption levels for approximately 275 years.[124] This is not to suggest that the nation is squandering natural gas reserves, but rather that sound public policy must recognize the value of natural gas and protect against the overuse of this resource.

The rapid depletion of natural gas reserves and related national security implications were highlighted in recent testimony by Federal Reserve Chairman Alan Greenspan before Congress.

> ...[I]mproving technologies have also increased the depletion rate of newly discovered gas reservoirs, placing a strain on supply that has required increasingly larger gross additions from drilling to maintain any given level of dry gas production. Depletion rates are estimated to have reached 27 percent last year, compared with 21 percent as recently as five years ago. The rise has been even more pronounced for conventionally produced gas because tight sands gas, which comprises an increasing share of new gas finds, exhibits a slower depletion rate than conventional wells...
>
> Increased marginal supplies from abroad, while likely to notably damp the levels and volatility of American natural gas prices, would expose us to possibly insecure sources of foreign supply, as it has for oil. But natural gas reserves are somewhat more widely dispersed than those of oil, for which three-fifths of proved world reserves reside in the Middle East. Nearly two-fifths of world natural gas reserves are in Russia and its former satellites, and one-third are in the Middle East.[125]

Continuing and expanding the use of natural gas for electricity production will place increased pressure on U.S. reserves and may require additional imports. Currently, the U.S. imports approximately 16% of its natural gas requirements almost exclusively from Canada. However, as Chairman Greenspan noted, expanding our gas imports would entail increased reliance on supplies from unstable areas where most of the world's natural gas reserves are found. This would make the U.S. more vulnerable to disruptions in supplies of vital energy resources. Moreover, such growth in gas imports would necessitate creating new and expensive

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[123] EIA, U.S. Crude Oil, Natural Gas, and Natural Gas Liquids, 2001 Annual Report, Chapter 4, Table 8 reports that the lower 48 states possess 174.7 trillion cubic feet (TCF) of proven reserves. According to the Annual Energy Outlook 2003, consumption of gas, in the US in 2001 was 22.7 TCF.

[124] Testimony of Mary Hutzler, Director EIA, before House Subcommittee on Energy and Air Quality, March 14, 2001.

[125] Testimony before the House Committee on Energy and Commerce, June 10, 2003.

infrastructure, including construction of a fleet of large tankers capable of transporting liquefied natural gas (LNG) and special port facilities to handle LNG shipments.

In contrast to natural gas-fired electric generation, the production of electricity from IGCC coal-fueled power plants would reduce pressure on natural gas supplies and prices, provide fuel diversity among new generation sources, and enhance national security. Expanded utilization of IGCC power plants will free up natural gas supplies, as well as valuable and hard to expand gas transmission facilities, for other uses.

These critical considerations are not adequately reflected in the pricing of electricity produced from natural gas-fired generation facilities and from IGCC power plants. Consequently, the true cost of using natural gas for electricity production is significantly understated and the value of IGCC power plants is not adequately recognized. Accordingly, new policies must be developed to correct this situation, including the two measures outlined below.

In addition, a study using the National Energy Modeling System (NEMS) could be undertaken to assess the impact of expanded IGCC deployment on natural gas prices, including the monetary benefits for residential and industrial consumers of natural gas.

4.2.5.2 Portfolio Standards

The deployment of IGCC power plants could be facilitated through national, regional, and/or state requirements that portfolios of power supplies include a minimum percentage of IGCC produced power. This policy could be implemented through the establishment of portfolio standards by federal legislation or FERC orders applicable to TSPs, ISOs and RTOs. It could also be accomplished on a state-by-state basis through legislation and regulatory orders.

There is precedent for this type of approach. Several states, including Connecticut, now require that a specific portion of the generation provided by retail suppliers (both utilities and independent retailers) be obtained from renewable energy sources.[126] And New York is currently conducting a proceeding to establish such standards.[127] The rationale for renewable portfolio standards applies with equal force to adopting such standards for IGCC--expanding the utilization of each of these resources provides major benefits consistent with sound, far-sighted public policy.

4.2.5.3 Credits for IGCC Power

A per KWh credit could be applied to electricity produced by IGCC power plants in the their early stages of operation. This would reflect the external benefits associated with IGCC power production (see Section 2), including reduced reliance on natural gas-fired generation.

The credit would be financed through uplift charges applied by TSPs, ISOs and RTOs, rather than through federal taxes or direct subsidies. As discussed in Subsection 4.2.2 above, there is precedent for such an approach since TSPs, ISOs and RTOs routinely impose uplift charges to recover the cost of measures that benefit all customers. This principle clearly applies to the

[126] Deregulation legislation in Connecticut calls for a Renewables Portfolio Standard (RPS), which will require all providers to obtain an increasing share of their power from renewable energy sources. The Connecticut RPS began at 0.75% in 2001 and will ultimately increase to 4% in 2009. The legislation also requires the utilities to collect a systems benefits charge (SBC), HB 5005 (April 29, 1998).

[127] New York Public Service Commission, Case 03-E-0188, *Proceeding on Motion of the Commission Regarding a Retail Renewable Portfolio Standard.*

increased use of IGCC coal projects in lieu of building more gas-fired plants. When natural gas is the marginal fuel, increases in natural gas prices cause higher average wholesale electric prices for all consumers. On the other hand, where IGCC baseload facilities are available, the number of hours that a gas plant will set the marginal price will be reduced, thereby lowering overall average electricity prices.

Alternatively, the credit for IGCC power production could be financed through System Benefit Charges ("SBCs") included in retail consumer utility bills. Such SBC-funded credits could be mandated by individual state regulatory commissions. However, as a practical matter, it would be difficult to implement a nationwide policy in this manner. To do so would require the adoption of uniform policies by state regulators throughout the nation. It would be more efficacious for state commissions to work with TSPs, RTOs, and ISOs in their respective regions to develop uplift charges to fund IGCC credits.

4.2.6 Federal and State Government Roles

Given the enormous benefits of expanded IGCC utilization, the federal government should play a strong role in this area. There are a number of situations where federal action is needed to overcome critical challenges identified in the survey discussed in Section 3. One particularly important matter is power plant siting and permitting.

Under Executive Order 13212, issued on May 18, 2001, President George W. Bush established the White House Task Force on Energy Project Streamlining. The Task Force's charge was stated as follows:

> **Sec. 3.** *Interagency Task Force.* There is established an interagency task force (Task Force) to monitor and assist the agencies in their efforts to expedite their review of permits or similar actions, as necessary, to accelerate the completion of energy-related projects, increase energy production and conservation, and improve transmission of energy. The Task Force also shall monitor and assist agencies in setting up appropriate mechanisms to coordinate Federal, State, tribal, and local permitting in geographic areas where increased permitting activity is expected. The Task Force shall be composed of representatives from the Departments of State, the Treasury, Defense, Agriculture, Housing and Urban Development, Justice, Commerce, Transportation, the Interior, Labor, Education, Health and Human Services, Energy, Veterans Affairs, the Environmental Protection Agency, Central Intelligence Agency, General Services Administration, Office of Management and Budget, Council of Economic Advisers, Domestic Policy Council, National Economic Council, and such other representatives as may be determined by the Chairman of the Council on Environmental Quality. The Task Force shall be chaired by the Chairman of the Council on Environmental Quality and housed at the Department of Energy for administrative purposes.

The White House Task Force could take the lead role in a federal initiative to facilitate the rapid commercialization and deployment of IGCC technology in the U.S. power sector. Specifically, the Task Force could initiate a state/federal-working group, in cooperation with the National Association of Regulatory Utility Commissioners ("NARUC"), to develop generic, uniform standards for siting and permitting IGCC facilities in multiple jurisdictions. Further, the Task Force could oversee a working group that would establish a single, dedicated information source and database that can assist in the siting and permitting of IGCC power plants, and in procurement of technology and equipment for IGCC projects. In addition, a number of actions by other federal agencies are essential to developing and implementing the policies and infrastructure needed to support the expanded deployment of IGCC power plants. Achievement of this goal will also require initiatives by state governments, particularly efforts coordinated through regional organizations and NARUC.

Federal/state interaction could be particularly useful in ensuring that IGCC is considered meaningfully in choice of technology determinations by state regulators. With the growth of wholesale markets and the increasing need for regional approaches to resource adequacy issues, there is a need for greater coordination between the states and the federal government in the generation planning process. The jurisdiction of the states with regard to siting and permitting power plants clearly should be maintained. However, it is important that choice of technology determinations in state permitting proceedings consider the use of IGCC facilities in appropriate circumstances. State regulators generally want to be presented with a broad range of evidence in such cases to ensure that their decisions on the choice of generation technology benefit ratepayers and the general welfare. This could be accomplished through intervention and presentation of testimony by federal agencies, such as DOE.

4.3 Summary and Details of Recommendations

The recommendations presented in this Report address six areas: (1) Siting and Permitting; (2) Project Financing and Plant Availability; (3) Co-production/National Security; (4) Strategies for Meeting Environmental Standards; (5) Relative Cost of IGCC Power Plants and Natural Gas Combustion Turbines; and (6) Federal and State Government Roles.

4.3.1 Siting and Permitting

--The federal and state governments could initiate an expedited process to develop a single set of standards specifically for siting and permitting IGCC power plants, including co-production processes.

--The states could develop Memoranda of Understanding specifying compatible regional standards to address air shed issues associated with IGCC permitting.

The licensing of IGCC power plants is far more complex than the process for permitting conventional coal or natural gas-fueled generation facilities. Currently, IGCC plants are subject to multiple federal and state environmental rules, and must be licensed, at a minimum, as electric generation units, syngas facilities and co-production plants. This is a major challenge to IGCC deployment. The White House Task Force on Energy Project Streamlining could establish a multi-jurisdictional group to develop uniform licensing standards for IGCC plants, and has indicated a willingness to do so.

4.3.2 Capital and Plant Availability

--A fund could be established to provide for the sharing of possible IGCC capital cost overruns.

Uncertainty regarding capital costs is a Top-Tier challenge to IGCC deployment. If capital costs exceeded a pre-determined target, there could be a sharing of the overruns between the developer and the federal government. This sharing mechanism could partially protect developers against cost overruns without unduly weakening their incentive to hold down project costs. The program could also be funded in part through an uplift charge.

--An IGCC Availability Assurance Program could be established.

Concern about possible limited availability of IGCC facilities in their early stages of operation is also a Top-Tier challenge to IGCC deployment. If early availability is low, the net present value of the project becomes diminished or possibly non-existent. The IGCC Availability Assurance Program, modeled after similar programs the federal government has established in other areas, could address those concerns. It could provide funding to partially defray the cost of possible extended outages in the first few years after a plant is installed.

Both of these programs could also be financed through developer payments and TSP uplift charges. Since IGCC facilities, if located strategically, could lower the average price of wholesale electric power, a share of those savings could be made available to fund this program. This would offset the need for direct federal funding and could establish the basis for a self-sustaining program.

4.3.3 Co-Production/National Security

--A study could be initiated to analyze the ability of IGCC power plants to operate on an economic dispatch basis to produce transportation fuels as well as electricity.

An IGCC facility can produce both electricity and transportation fuels--i.e., co-production. The value of the plant can be optimized by turning out each product when its price is highest--i.e., producing electricity during the day when demand--and prices--are high, and producing transportation fuels when electricity demand and wholesale electric prices are low. Moreover, the production of transportation fuels from a number of such facilities could displace substantial amounts of imported oil and thereby provide significant national security benefits. The fact that the Wabash plant operates in part as a "load following" unit shows that IGCC plants can quickly ramp up and down and therefore can be operated on an economic dispatch basis. In view of these potential benefits, a detailed study could be initiated to evaluate the economics of co-producing electricity and transportation fuel in an IGCC power plant.

4.3.4 Strategies for Meeting Environmental Standards

--Probabilistic projections of future emissions policies could be developed.

--A study could be undertaken to examine the economics of addressing potential emissions reduction requirements by repowering existing plants rather than pursuing a piecemeal approach to treating individual emissions.

--Strong accounting standards could be developed to recognize the value of future emissions reduction credits that will accrue to IGCC projects.

--The forward value of nitrogen oxide and sulfur oxide emissions allowances could be monetized through the creation of forward markets and valued through accounting standards that allow recognition of these assets by the Securities and Exchange Commission and state PUCs.

--The forward value of obviating incremental mercury and particulate emissions control expenditures could be monetized through the creation and recognition of forward markets.

--A study could be undertaken to assess the potential value of water credits related to the use of animal waste as a feedstock for IGCC power plants.

--A study, similar to the one presented in this Report, could be undertaken to address institutional challenges to commercialization and deployment of carbon dioxide sequestration technologies.

The deployment of IGCC technology is substantially hindered by uncertainty regarding future regulations, the piecemeal approach of the electric industry and regulators to meeting future environmental standards, and the absence of efficient markets in which the forward value of emissions reductions can be monetized. As a result, the value of emissions reductions, particularly with respect to nitrogen oxides, cannot be recognized as an offset to the capital costs of IGCC technology--which survey respondents identified as a critical challenge to IGCC deployment. Consequently, determinations regarding the choice of technology for new generating facilities and for repowering existing plants cannot be made on a sound economic basis.

Appropriate measures could be implemented to monetize or otherwise recognize the future value of emissions allowances. A strong set of accounting standards reflecting the valuation of these credits could also be developed.

In addition, the discounted future value of obviating mercury and particulate emissions control expenditures should be factored into choice of technology determinations.

While not currently required, carbon dioxide sequestration may become an important factor in the next decade as concern over global warming grows, and trading of carbon dioxide emissions develops and expands. Currently, sequestration is not cost-effective.[128] However, substantial technical research is being undertaken to significantly lower these costs. Institutional factors will also have to be addressed in this regard. Accordingly, a study, similar to the one presented in this Report, could be undertaken to analyze the institutional challenges to commercialization and deployment of carbon dioxide sequestration technologies, and provide recommendations for overcoming them.

4.3.5 Relative Cost of IGCC Power and Natural Gas Combustion Turbines

--Measures could be developed to facilitate deployment of IGCC power plants and reduce undue reliance on natural gas combustion turbines, thereby decreasing pressure on limited natural gas supplies and freeing up natural gas for essential uses such as industrial processes and residential heating.

--Transmission Service Providers (TSPs), Independent System Operators (ISOs), and Regional Transmission Organizations (RTOs) could be required to establish target portfolio standards for IGCC-produced power.

[128] AEP has estimated that the cost of sequestration is approximately $200 per ton of carbon dioxide. Since about one ton of carbon dioxide is produced per MWh generated, the process is clearly very uneconomic.

--TSPs, ISOs and RTOs could be required to provide modest credits financed through uplift charges for electricity produced by IGCC power plants in their early stages of operation.

--A study using the National Energy Modeling System (NEMS) could be undertaken to assess the impact of expanded IGCC deployment on natural gas prices.

The survey of stakeholders indicated that the most significant challenge to the deployment of IGCC power plants is their higher capital costs relative to natural gas combustion turbines (NGCTs), which have accounted for vast majority of new generating facilities in recent years. However, the pricing of electricity from NGCTs and IGCC power plants does not adequately reflect several critical considerations including the importance of using natural gas in industrial processes and residential heating, the recent run-up in natural gas prices resulting from increased pressure on supplies, the accelerated depletion of the nation's limited reserves of natural gas, and the need for increased reliance on gas supplies from unstable areas of the world as domestic supplies are used up. Accordingly, new policies such as those recommended herein should be developed to address this situation.

4.3.6 Federal and State Actions

--The EPA could initiate negotiations with owners of existing conventional coal-fueled power plants to explore means of monetizing or otherwise recognizing the benefits of future emissions reductions in order to develop a comprehensive policy for lowering emissions rather than pursuing a piecemeal, incremental approach.

The analysis developed in this Report suggests that meeting requirements for reduced emissions of sulfur oxides, nitrogen oxides, mercury, and particulates by using IGCC to repower conventional coal-fueled generating plants is likely to be far less costly than meeting each of the requirements separately pursuant to a piecemeal approach. Accordingly, the EPA could initiate negotiations with coal plant owners and operators to develop a comprehensive approach for meeting existing and anticipated emissions reduction requirements based on repowering with IGCC technology. These discussions could consider mechanisms for monetizing or otherwise recognizing the value of future reductions in nitrogen oxides and sulfur dioxide, as well as other pollutants such as mercury that are likely to be regulated in the future. These efforts could also result in long-term, e.g., 20-30 year, settlements.

--A strong federal GHG emissions reduction registry, with effective measurement and verification standards, could be established to facilitate private, voluntary bilateral transactions. The federal GHG registry could be made compatible with the GHG emissions reduction registries that are being developed by other nations, and with emissions credit markets that are being created in the U.S. and abroad.

--States and/or regions, working through NARUC, could establish uniform GHG registries that are compatible with the federal registry as well those created abroad.