Final Report
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David and Lucile Packard Foundation
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IGCC Financing Project
Energy Technology Innovation Project
Belfer Center for Science & International Affairs
John F. Kennedy School of Government
Harvard University

APPENDIX A—ATTACHMENTS

1. Executive Summary of 3Party Covenant paper
2. National Gasification Strategy paper
3. Article in Forbes magazine
4. April 21, 2005 Senate Energy Committee Testimony
5. Article in Public Utility Fortnightly
6. Salazar National Gasification Strategy bill
7. Summary of Energy Policy Act of 2005 Title XVII--Incentives for Innovative Technologies.

Attachment 1

Executive Summary
of 3Party Covenant Paper

Deploying IGCC In this Decade With 3Party Covenant Financing

Volume I

May 2005 Revision

William G. Rosenberg, Dwight C. Alpern, Michael R. Walker

Energy Technology Innovation Project
a joint project of the
Science, Technology and Public Policy Program
and the
Environment and Natural Resources Program
Belfer Center for Science and International Affairs

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Finally, thanks to all who attended the February 11, 2004 workshop to discuss the draft report and offer comments and suggestions. Although the arguments and ideas contained in this work are strictly those of the authors and do not necessarily represent the views of the sponsors or any of the other experts consulted along the way, the authors are well aware that without all of the advice, guidance, and support, successful completion would not have been feasible. Thank you to our families who put up with extended work hours and everyone that helped this project along as it endeavored to make a contribution in a very important national energy and environmental policy arena.

FOREWORD

These two volumes emanate from fourteen months of research, discussion and countless drafts. The three authors, William Rosenberg, Dwight Alpern, and Michael Walker, conducted meetings with key players, including officials from both the federal and state government, representatives of the power, engineering, coal and chemical industries, environmental groups and academic experts. We are especially grateful for the cooperation of the Carbon Mitigation Initiative at Princeton University and two of its leaders, Robert Socolow and Robert Williams, and for the continuing advice from the MIT Laboratory for Energy and the Environment.

Both of these volumes have been extensively peer reviewed by a team of experts, including faculty at Harvard, Yale, and Princeton. The authors have consulted with officials from the Electric Power Research Institute (EPRI), Center for Clean Air Policy (CCAP), and the National Association of Regulatory Utility Commissioners (NARUC). The authors also benefited from a workshop held at the John F. Kennedy School in February, 2004. Over eighty experts from across the country participated in a discussion on opportunities to overcome the financial and political challenges confronting the deployment and commercialization of Integrated Gasification Combined Cycle technologies (IGCC), (see the ENRP rapporteur's report: “Workshop on Integrated Gasification Combined Cycle: Financing and Deploying IGCC Technologies in this Decade,” #2004-06).

These reports are part of a three-year program in the Kennedy School's Energy Technology Innovation Project (ETIP), a joint effort of the Environment and Natural Resources Program (ENRP) and the Science, Technology and Public Policy Program (STPP). ETIP has fostered extensive work on the obstacles and opportunities for development and utilization of IGCC technologies in China and India, as well as in the United States.

These efforts are stimulated by three policy imperatives: the need to increase the use of indigenous coal supplies and to meet a growing demand for electricity; the need to clean up our air, and reduce the threat of global climate change; and the need to address the nation's energy security. These reports provide a blueprint of how the United States might take the initial steps to commercially deploy IGCC technology to significantly improve our air, economy, and national interest.

We are very grateful for the support of the National Commission on Energy Policy, the Department of Energy, the Environmental Protection Agency, the Hewlett Foundation, the Packard Foundation, the Roy Family Fund, and the hundreds of experts who have generously given the authors the benefit of their advice and counsel.

John Holdren and Henry Lee
Co-chairs, Energy Technology and Innovation Project

REPORT ORGANIZATION

The paper is divided into two volumes. Volume I describes IGCC technology, why it is an important advanced clean coal technology for generating electricity, the hurdles to near-term deployment, the 3Party Covenant financing and regulatory program to stimulate near-term IGCC deployment, and how the 3Party Covenant improves the economics of IGCC technology to make it competitive. Appendix A of Volume I outlines the components of federal legislation that are needed to implement the 3Party Covenant.

Volume II provides a detailed legal analysis of the federal and state authorities and regulatory mechanisms for implementing the 3Party Covenant, including a review of traditional electric utility regulatory systems, the current regulatory systems in 5 specific states, and a model regulatory mechanism for review and approval of IGCC project costs under the 3Party Covenant.

May 2005 Revision

This paper is a revised version of the authors' July 2004 working paper. The update adjusts the equity return used in calculating levelized carrying charges and energy costs in the report by reducing the modeled return from 18.6 percent to 11.5 percent. This change eliminates an unintentional double counting of tax implications that was identified in calculations presented in the July 2004 report. The update also includes some other minor changes, which reflect or result from the adjustment of the modeled equity return.

TABLE OF CONTENTS

VOLUME I

EXECUTIVE SUMMARY

This paper describes a 3Party Covenant financing and regulatory proposal ("3Party Covenant") aimed at reducing financing costs and providing a technology risk tolerant investment structure to stimulate initial deployment of 3,500 MW (about six 550 MW plants) of Integrated Gasification Combined Cycle (IGCC) coal generation power plants in this decade. The 3Party Covenant is an arrangement between the federal government, state utility commission (state PUC), and equity investor[1] that serves to lower IGCC cost of capital[2] by reducing the cost of debt, raising the debt/equity ratio, minimizing construction financing costs, and allocating financial risk. The 3Party Covenant reduces the cost of capital component of energy costs from new IGCC facilities by approximately 30 percent and the overall cost of energy about 17 percent, making power produced from IGCC technology cost competitive with pulverized coal (PC)[3] and natural gas combined cycle (NGCC) generation.

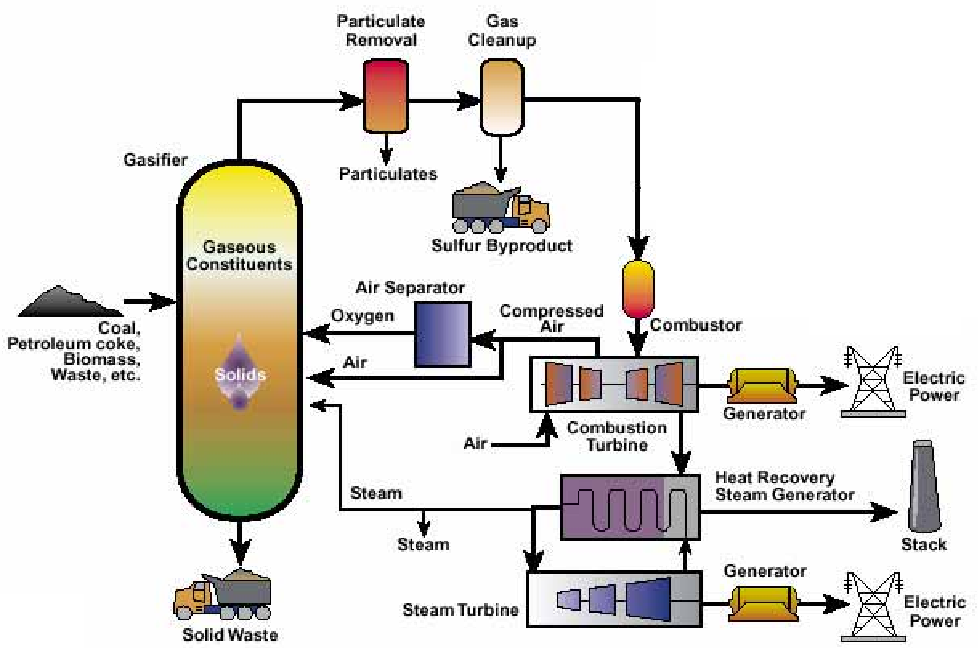
ES-1. Integrated Gasification Combined Cycle Generation

IGCC is a power generation process that integrates a gasification system with a conventional combustion turbine combined cycle power block. As illustrated in Figure 1-1, the gasification system converts coal (or other solid or liquid feedstocks such as petroleum coke or heavy oils) into a gaseous "syngas," which is made of predominately hydrogen (H_2) and carbon monoxide (CO). The combustible syngas is used to fuel a combustion turbine to generate electricity, and the exhaust heat from the combustion turbine is used to produce steam for a second generation cycle and provide steam to the gasification process.[4]

Despite the worldwide commercial use and acceptance of gasification processes and combined cycle power systems, IGCC is not perceived in the U.S. to have sufficient operating experience to be ready to use in commercial applications.[5] Each major component of IGCC has been broadly utilized in industrial and power generation applications, but the integration of a coal gasification island with a combined cycle power block to produce commercial electricity as a primary output is relatively new and has

[1] The "equity investor" is likely to be either an electric utility company (or a municipal utility or rural electric cooperative), or independent power company with a purchase contract with a utility (or a contract with comparable credit rating), that provides the equity for a project.
[2] As used in this paper, the term "cost of capital" means debt interest and authorized return on equity.
[3] As used in this paper, the term "PC" or "super-critical PC"means a power generation process that uses a super-critical, pulverized coal-fired boiler incorporating the latest emissions control technologies, including fabric filter baghouses or electrostatic precipitators for particulate control, flue gas desulfurization (FGD) for sulfur dioxide control, and selective catalytic reduction (SCR) to control oxides of nitrogen.
[4] With minor adjustments, combustion turbines designed to operate on natural gas can use syngas. The primary difference that affects the turbine is that syngas has a lower heating value than natural gas, which makes for a larger mass flow of fuel through the turbine that requires different piping and increases turbine output. Natural gas has a heating value of 1,026 btu/ft^3, while syngas has a heating value of 200-300 btu/ft^3.
[5] See David Berg & Andrew Patterson, "IGCC Risk Framework Study," DOE Policy Office, Presentation to Gasification Technology Council, May 20, 2004.

Figure ES-1. IGCC Power Plant



Source: NETL

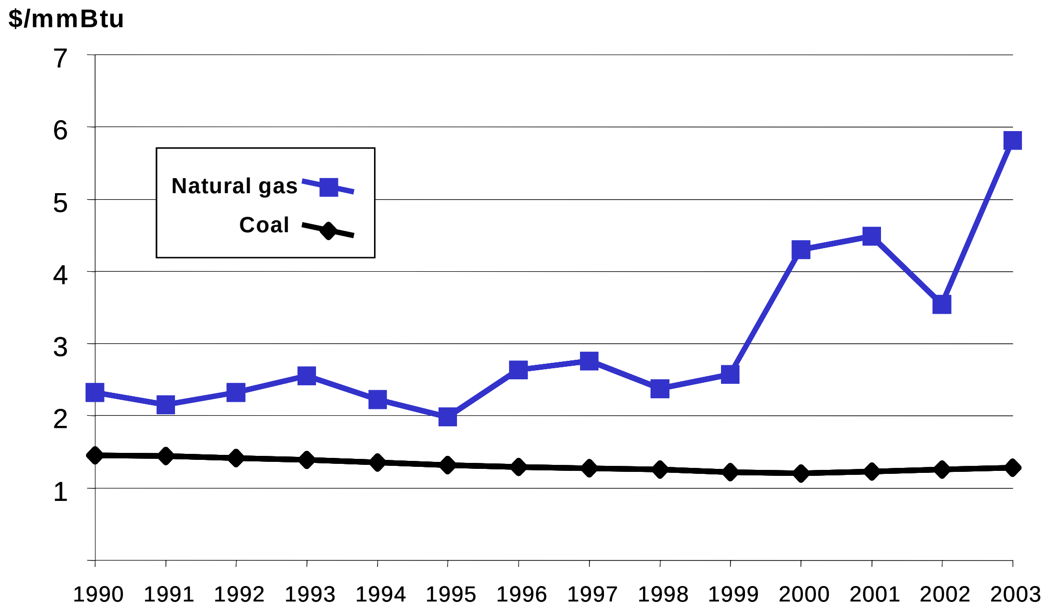
been demonstrated at only a handful of facilities around the world. The Overnight Capital Cost[6] of the engineering, procurement, and construction (EPC) contract for IGCC is currently estimated to be about 20 percent higher than PC systems[7] and commercial reliability has not yet been established. As a result, investments to build IGCC facilities to generate power have not materialized despite significant public and private sector interest in the technology.

ES-2. Why IGCC

IGCC was selected as the focus of this paper because it is a commercially ready, advanced technology for generating electricity with coal that is widely supported and can substantially reduce air emissions, water consumption, and solid waste production from

[6] As used in this paper, the term "Overnight Capital Cost" means the bare cost of designing and building a power plant, including engineering, procurement, construction and contingencies, but not considering cost of capital.
[7] However, the current market for combustion turbines, a key component of IGCC power plants, is very soft, which may allow for more cost-competitive IGCC than most studies indicate. Completed natural gas combined cycle units and unused turbines that have never been installed are available for purchase at a very substantial discount. According to NETL, there are as many as 50 turbines currently in warehouses that could potentially be used for new power plants.

Figure ES-2. Average Delivered Fuel Prices to Electric Generators



Sources: 1990-2001, EIA, Electric Power Annual 2001, March 2003.
2002-2003, EIA, Electric Power Monthly, September 2003.

coal power plants.[8] The Department of Energy (DOE) has invested billions of dollars over the last 20 years to support the technology, and there are fully demonstrated and commercially operating plants in the U.S., Europe, and Japan. IGCC also offers the potential of a technical pathway for cost effective separation and capture of carbon dioxide (CO_2) emissions and for co-production of hydrogen. These environmental attributes make it an important technology for enabling the substantial energy, economic, and national security benefits of coal use for electricity generation to be achieved with minimal environmental impact.

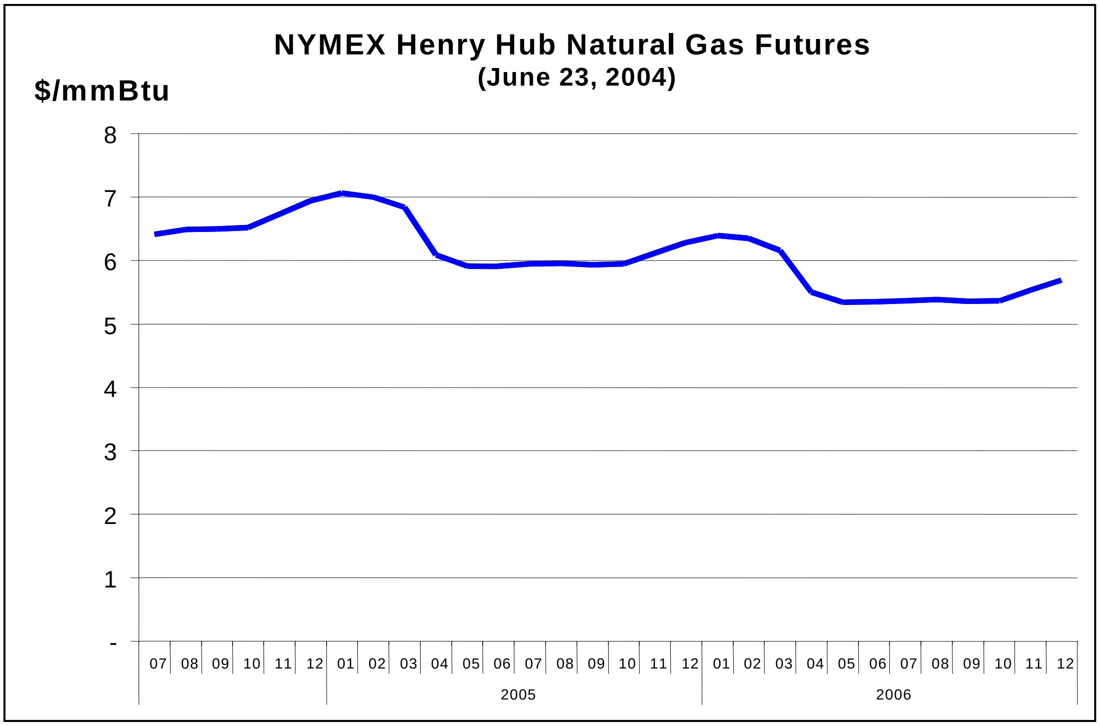
Coal is a vital U.S. energy resource that currently fuels over 50% of U.S. electricity generation. The U.S. has 25 percent of the world's proven coal reserves, more than any other country in the world. This supply enables the U.S. to be a net coal exporter.[9] In contrast, the U.S. has less than 3 percent of world oil and natural gas reserves,[10] imports over 50% of its oil supply (compared to 28 percent just prior to the first Arab Oil

[8] The type of financing program described in this paper could also be effective for other technologies that have similar environmental characteristics.

[9] Estimated recoverable coal reserves in the U.S. are 275 billion tons, which is approximately 25 percent of world reserves and more than a 250-year supply at current consumption (See National Mining Association, "Fast Facts About Coal," http://www.nma.org/statistics, Sept. 9, 2003).

[10] U.S. oil and natural gas reserves are estimated to be less than 2 percent and 3 percent of world totals, respectively. (See EIA, "International Energy Annual 2001," Table 8.1).

Figure ES-3. Henry Hub Natural Gas Futures



Embargo), and is expanding natural gas imports from mid-eastern and other countries through development of liquefied natural gas (LNG) production and transport facilities. [11]

Real coal prices have declined 63 percent since 1980 and real retail electricity prices, which are directly affected by coal prices, have declined 21 percent over the same period.[12] The average price of coal delivered to electric generators in December, 2003 was $1.25/mmBtu, compared to $3.90/mmBtu for petroleum and $5.24/mmBtu for delivered natural gas.[13] As illustrated in Figure ES-2, electric generator natural gas prices have become increasingly volatile in recent years while coal prices have remained relatively stable and slowly declined for the past decade. Coal price stability translates into stable generating costs and stable electricity prices when coal is the dominant generation fuel. Domestic coal, which is geographically dispersed across the country, transported by rail and barge, and can be stockpiled for 30-90 days at generating facilities, is a secure and reliable energy source.

Coal electricity generation can also help relieve pressure on natural gas availability and prices that are adversely affecting other sectors of the economy. Natural gas prices in 2003 were two to three times above historic averages and, as illustrated in Figure ES-3, natural gas futures suggest prices will remain high for at least the next several years.

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[11] See *New York Times*, Oct. 13, 2003, p. W1. See also *New York Times*, Dec. 9, 2003, p. C4.
[12] See EIA, "Annual Energy Review 2002," October 2003, Tables 7.8 and 8.6.
[13] See EIA, "Electric Power Monthly," April 2004, Table ES1.A.

These high natural gas prices caused widespread, adverse impacts on the U.S. economy and economic competitiveness, including significant job losses in manufacturing and chemicals industries.[14] One factor supporting high natural gas prices and price forecasts is the increased demand resulting from construction of new natural gas-fired electric generation. According to EIA, natural gas consumption by electric generators increased 40% between 1997 and 2002 and will increase another 51% by 2025.[15] Coal generation in general, and IGCC in particular (which can be used to refuel natural gas plants to coal), can help reduce pressure on natural gas prices.[16]

For the nation to enjoy the energy and economic advantages of coal generation without risking significant adverse environmental and health impacts, advanced coal generation technologies need to be deployed that address air pollution, climate change, and other environmental concerns associated with traditional coal combustion technologies. IGCC offers the potential for coal generation with significantly improved environmental performance, particularly reduced air emissions, through gasification and removal of impurities prior to combustion. This emissions control method is very different from PC power plants, which achieve virtually all emissions control through combustion and post combustion controls that treat exhaust gases.[17] Because the syngas produced in the gasification process has a greater concentration of pollutants, lower mass flow rate, and higher pressure than stack exhaust gas, emissions control through syngas cleanup is generally more cost effective than post combustion treatment to achieve the same or greater emissions reductions.

For example, there is no single proven technology available today that can uniformly control mercury emissions from PC power plants in a cost-effective manner, while consistently achieving mercury removal levels of 90 percent.[18] In contrast, IGCC power plants have the potential to cost-effectively achieve very high (95-99 percent) mercury

[14] The economic consequences of high prices are described in the House Speaker's Task Force for Affordable Natural Gas report, which states: "Because domestically produced natural gas is so vital to our nation's energy balance, rising prices make our nation less competitive. When prices rise, factories close. Good, high paying jobs are imported overseas. Today's high natural gas prices are doing just that. We are losing manufacturing jobs in the chemicals, plastics, steel, automotive, glass, fertilizer, fabrication, textile, pharmaceutical, agribusiness and high tech industries." House Energy and Commerce, The Task Force for Affordable Natural Gas, Natural Gas: Our Current Situation (Sept. 30, 2003).

[15] See http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2A.htm; See also EIA, Annual Energy Outlook 2004, Table A-13.

[16] In contrast to natural gas, increased use of coal for electricity generation, has very little impact on other sectors of the economy because coal use in the U.S. is essentially dedicated to electricity generation, with 90 percent of coal consumption in the U.S. attributable to electric generators. See EIA, "Annual Energy Outlook 2003 (AEO 2003)," Table A16, Jan. 2003.

[17] Typical combustion and post-combustion controls required of new PC power plants include Flue Gas Desulfurization (FGD, or "scrubbers") for SO_2 control, low NOx burners and Selective Catalytic Reduction (SCR) for NOx control, and Electro-Static Precipitators (ESP) or fabric filter baghouses for particulate control. These technologies add to the capital cost, size and complexity of new PC power plants and decrease plant efficiency because of their energy consumption.

[18] NETL, "The Cost of Mercury Removal in an IGCC Plant," p. 1, Sept. 2002.

control with established technology.[19] In addition, IGCC technology offers the potential for separating and capturing CO_2 emissions (and producing pure hydrogen) by adding water-gas shift reactors to the syngas treatment system and physical absorption processes to remove CO_2. These processes are commercially proven in industrial processes, and several studies have shown this to be a more cost-effective approach to CO_2 capture[20] with proven technology than capturing CO_2 from the flue gas of a PC boiler.[21]

U.S. leadership in the deployment of IGCC technology also could be very beneficial in steering coal-intensive developing countries, such as China and India, towards more environmentally and climate friendly coal use. Near-term deployment of technology capable of addressing CO_2 emissions is critical to avoid locking in traditional steam coal technology for the 30 to 50 year life of new coal plants for the 1,400 giga-watts of new capacity projected to come on line by 2030.[22]

ES-3. IGCC Deployment

For IGCC to be perceived as mature, reliable, and economic, more commercial experience needs to be gained through deployment. However, in order to attract the investment needed for deployment, the technology needs to be perceived as commercially mature, reliable, and economic. Helping resolve this dilemma through commercial deployment of an initial fleet of IGCC power plants is the principal objective of the 3Party Covenant financing and regulatory program.

High natural gas prices, broad political interest, and a growing need for new base load electricity supplies are creating a window of opportunity for IGCC. Many diverse interests, including coal producers and utilities, state and federal government officials, industrial and residential natural gas consumers, and environmental organizations have expressed support for the technology.

At the same time, there has been a resurgence of proposals for PC coal power plant development, with over 94 new coal plants identified as under development in the U.S. as of February, 2004. As illustrated in Figure ES-4, during the period 2005 to 2015, EIA projects the addition of 57 giga-watts of new coal, nuclear, and combined cycle gas generating capacity to serve electricity demand, which is equivalent to about 100 new

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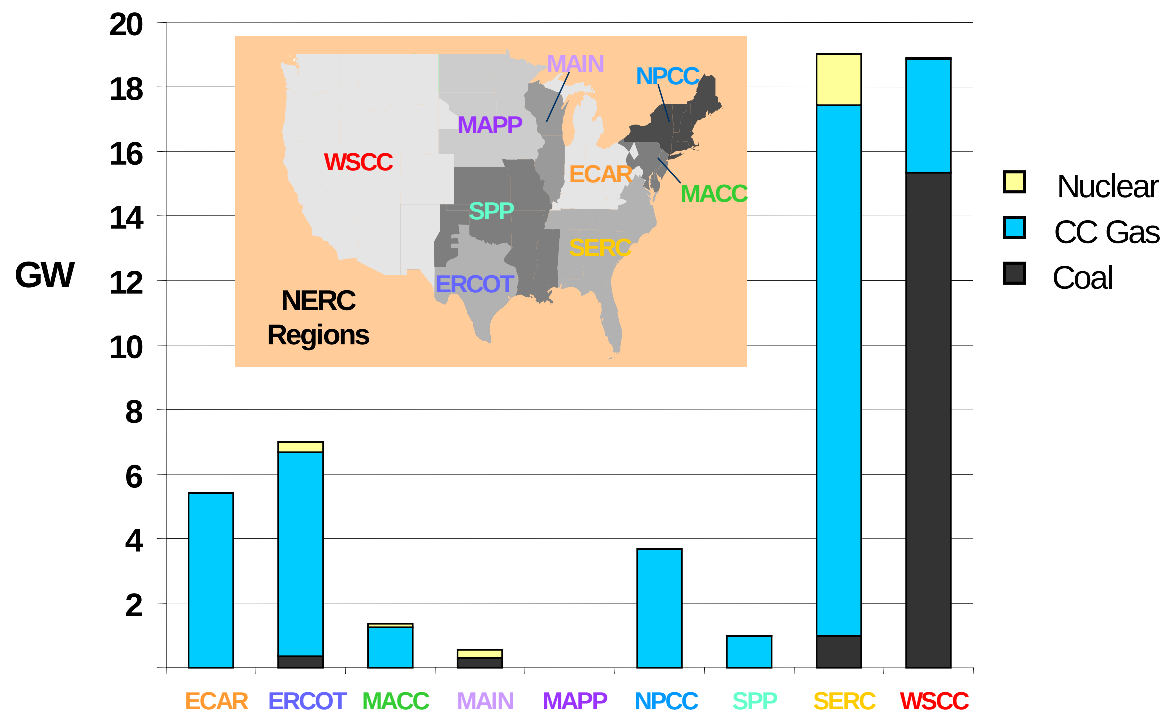
[19] Id.

[20] Although capturing CO_2 is only the first step in controlling it (because it must be sequestered if emissions are to be reduced), most experts agree that extensive research and large-scale demonstration projects are needed on sequestration before a commercial IGCC or other coal power plant would be in a position to sequester its CO_2. Sequestration is not specifically addressed in this paper because it is viewed by the authors as beyond the scope of commercialization of a small initial fleet of IGCC plants, which is the objective of the 3Party Covenant proposal.

[21] See Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000; See also DOE—EPRI Report 1000316, Dec. 2000.

[22] See Fridtjof Unander and Carmen Difiglio, International Energy Agency, Energy Technology Policy Division, "Energy and Technology Perspectives: Insights from IEA modeling," presented at the National Energy Modeling System/Annual Energy Outlook 2003 Conference, Mar. 18, 2003.

Figure ES-4. EIA 2005-2015 Coal, Nuclear, and NGCC Capacity Additions



Source: EIA, Annual Energy Outlook 2004, Supplemental Regional Data, Table 75.

550 MW power plants (average of 10 per year). If current fuel price trends continue, a substantial portion of the new capacity is likely to be coal fueled utilizing PC technology. A window of opportunity exists for IGCC technology to account for an important share of this new capacity and prove its commercial viability in the near term.

In addition, market availability of underutilized NGCC generation assets at discount prices presents an opportunity for cost-effective coal gasification refueling. The combined cycle power block associated with a NGCC power plant is essentially the same as the combined cycle power block needed for an IGCC facility. To convert an existing natural gas turbine to use synthesis gas from a coal gasifier is a minor adjustment estimated to cost only $5 million for a typical 350 MW plant, or roughly $15/kW.[23] This cost is more than made up for by the savings associated with using a financially distressed asset to provide the combined cycle power block for the IGCC plant. Furthermore, for an owner of a distressed NGCC facility, refueling to IGCC means taking a depressed asset facing large write-offs that is operating at only a fraction of its capacity and repositioning it to operate as a base load coal facility that operates at a high (80-90%) capacity factor with close to par valuation. With 3Party Covenant financing,

[23] NETL, "Potential for NGCC Plant Conversion to a Coal-Based IGCC Plant - - A Preliminary Study," May 2004.

the cost of energy from the resulting plant is as much as 19 percent below the cost of energy from a new PC plant (see Figure ES-10 below).

Despite these opportunities, investments to design and build commercial IGCC power plants in the U.S. have not yet materialized due to cost and risk concerns. A 2004 survey by DOE indicates that the three leading risk factors perceived by industry to be associated with IGCC investments are high capital costs, excessive down time, and difficulty with financing.[24] The financing hurdle is made all the more difficult by the fact the electric utility industry today is weaker financially than it has been in the past. A November 2003 analyst report by Standards and Poors indicated that:

> "the average credit rating for the electric utility sector is now firmly in the 'BBB' category, down from the 'A' category three years ago. Furthermore, prospects for credit quality remain challenging, as indicated by rating outlooks, 40 percent of which are negative."[25]

Lower credit ratings make if more difficult and costly for power companies to raise money for large, capital-intensive coal projects (whether PC or IGCC) costing close to a billion dollars. Add the uncertainty of a relatively new generating technology such as IGCC, and financing becomes a serious constraint to deployment.

ES-4. 3Party Covenant Financing and Regulatory Program

The 3Party Covenant is a financing and regulatory program for providing developers of IGCC power plants with ready access to capital at lower cost in an environment that tolerates technology risk. By so doing, the 3Party Covenant addresses the fundamental economic and financial challenges inhibiting IGCC deployment. The program is designed to facilitate development of an initial fleet of commercial IGCC plants this decade to establish the commercial viability of the technology and reduce costs.[26]

As illustrated in Figure ES-5, the 3Party Covenant is a financial and regulatory arrangement among a federal agency, a state PUC (or other utility rate setting body), and an equity investor. Under the 3Party Covenant, the federal government provides AAA credit, the state PUC provides an assured revenue stream to cover cost of capital and protect the federal credit, and the owner provides equity and know-how to build the IGCC project with appropriate guarantees from an EPC firm (which in turn has underlying warranties from equipment vendors). In return, the federal government

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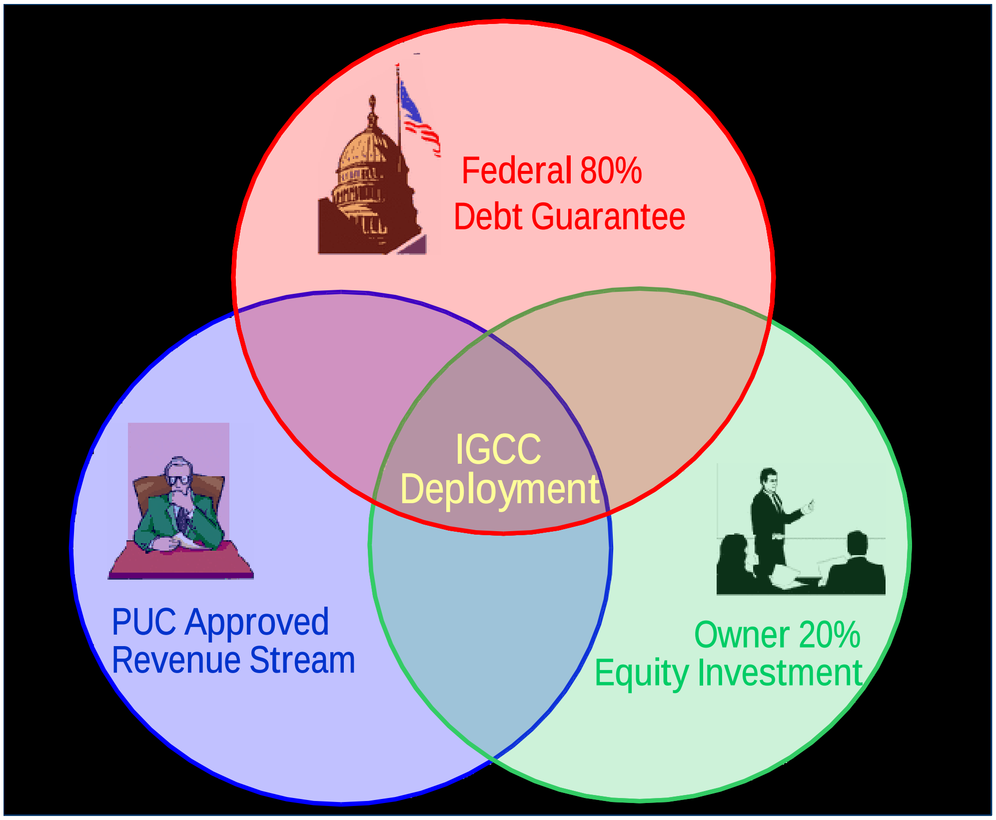
[24] See David Berg & Andrew Patterson, "IGCC Risk Framework Study," DOE Policy Office, Presentation to Gasification Technology Council, May 20, 2004.

[25] Ronald M Baron, *"U.S. Power and Energy Credit Outlook Not Promising; Few Bright Spots,"* Standard & Poors, Nov. 11, 2003.

[26] Public sector support for commercialization of innovative new technologies was identified as an important recommendation of the PCAST Energy R&D Panel in 1997, which recommended among other things "targeted efforts to improve the prospects of commercialization of the fruits of publicly funded energy R&D in specific areas." (See PCAST Energy R&D Panel 1997, *Federal Energy Research & Development for the Challenges of the 21st Century*, Report of the Energy R&D Panel, The President's Committee of Advisors on Science and Technology, Nov., 1997).

Figure ES-5. 3Party Covenant Illustration



stimulates IGCC deployment to support energy, national security, and environmental policy objectives at low federal cost; the state receives competitively priced power, economic development (investment and jobs), and environmental improvement; and the equity investor receives access to non-recourse, low-cost debt, assured equity returns, and an economic base-load power plant.

The three key elements are as follows:

> *Federal Loan Guarantee:* The program for implementing the 3Party Covenant is established through federal legislation authorizing a federal loan guarantee to finance IGCC projects. The terms of the federal guarantee provide for an 80/20 debt to equity financing structure and require that a proposed project obtain from a state PUC an assured revenue stream to cover return of capital, cost of capital, and operating costs. The terms also require the project to have appropriate construction guarantees from the EPC firm hired to design and build the plant, and to meet stringent environmental performance specifications. The terms would also enable the project to have available an additional draw on the federally guaranteed debt ("Line of Credit") of up to 15 percent of project Overnight Capital Costs (to be matched with a 20 percent equity contribution when drawn).

State PUC Approval Process: States interested in participating in the program voluntarily opt-in by adopting utility regulatory provisions for state PUC review and approval of IGCC project costs,[27] which in some states will require legislative action to create appropriate enabling authority.

Specifically, a state PUC (or potentially another ratemaking body in the case of a municipal utility or rural electric cooperative), acting under state enabling authority, assures dedicated revenues to qualifying IGCC projects sufficient to cover return of capital (depreciation and amortization), cost of capital (interest and authorized return on equity), taxes, and operating costs (e.g., operation and maintenance, fuel costs, and taxes).[28] The state PUC provides this revenue certainty through utility rates in states with traditional regulation of retail electricity sales, or through non-bypassable wires charges in states with competitive retail electricity sales, by certifying (after appropriate review) that the plant qualifies for cost recovery and establishing rate mechanisms to provide recovery of approved costs, including cost of capital. The certification by the state PUC occurs upfront when the decision to proceed with the project is being made, and the prudence review by the state PUC and cost recovery occur on an ongoing basis starting during construction, which reduces the construction risks borne by the developer, avoids accrual of construction financing expenses, and protects ratepayers.

Equity Investor: The equity investor under the 3Party Covenant is likely to be either an electric utility (or a municipal utility or rural electric cooperative) or an independent power producer that secures a long-term power contract with a utility (or a contract with a comparable credit rating). The investor contributes equity for 20 percent of the Total Plant Investment and negotiates performance guarantees to develop, construct, and operate the IGCC plant. A fair equity return is determined and approved by the state PUC before construction begins.

The 3Party Covenant is distinguished from other federal financing programs because a principal party is a state PUC (or potentially another ratemaking body for a municipal utility or rural electric cooperative), which effectively assures the revenue stream needed to service the federally guaranteed debt. The regulatory body, operating under state enabling law, reviews and approves the IGCC plant proposal upfront, determines the need for power, establishes the mechanism for allocation of project risks and recovery of approved costs, conducts ongoing prudence review during construction and operation, and determines the amount and timing of project revenues. The 3Party Covenant requires states that want to participate to establish a review and approval process that provides for

[27] As used in this report, the term "project costs" refers to all costs associated with building and operating a power plant, including all development costs, capital and financing costs, and operating costs.

[28] Depending on the ownership structure and sales profile (i.e., retail sales versus sales for resale) of the IGCC project, the Federal Energy Regulatory Commission (FERC) may take on some of the role otherwise assigned to the state PUC.

cost recovery assurances to protect the federal loan guarantee before the guarantee becomes effective.

The 3Party Covenant is designed to benefit and protect ratepayers by enabling them to receive lower cost (because of access to lower cost financing)[29] and less polluting power without being required to take excessive risk. Ratepayer risks are mitigated under the 3Party Covenant by EPC contractor construction guarantees (and underlying equipment vendor warranties) required to cover construction risks, a 15 percent Line of Credit (percentages based on Overnight Capital Costs) to cover construction and operating risks that are the responsibility of the owner, and the state PUC process evaluating the prudence of the IGCC investment decision and operation.[30] It is ultimately up to the state PUC, through a transparent public process, to determine whether the public benefits of building a new IGCC power plant under the 3Party Covenant outweigh the risks to ratepayers.[31] The decision will only be made where the PUC determines that there is a need for new base load power and will entail weighing the future benefits, risks, and cost of 3Party Covenant financed IGCC against the benefits, risks, and costs of conventionally financed alternative base load generation (PC).[32]

Once the state PUC assures revenues to service the federally guaranteed loan, the amount of the loan that must be scored as a federal budget expense is likely to be significantly lower, because risk of default is significantly reduced. The budgetary treatment of federal loan guarantee programs is governed by the Federal Credit Reform Act of 1990 (FCRA). FCRA makes commitments of federal loan guarantees contingent upon prior budget appropriations (“scoring”) of enough funds to cover the estimated present value cost associated with the guarantees. The present value cost is based on an estimate of the following cash flows at the time the loan guarantee is disbursed:

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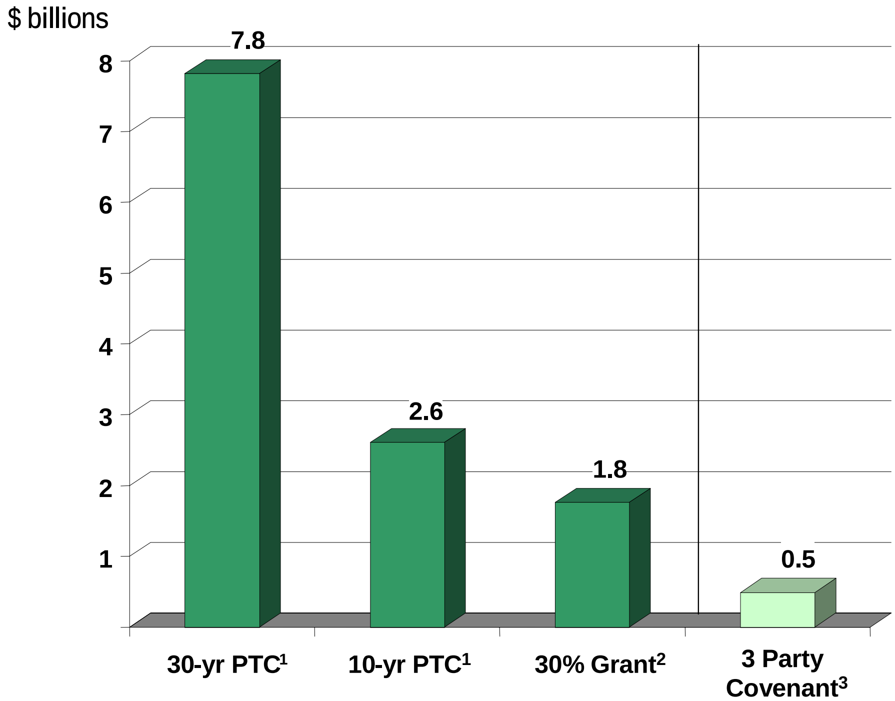
[29] The cost of capital component of energy costs on a capital intensive coal fueled generating plant is typically 60-70% of total energy costs. Substantially lower costs of capital under the 3Party Covenant, as explained in ES-5, reduce the ratepayer supported costs of IGCC to levels competitive with PC.

[30] Use of redundant gasifier capacity, which is assumed in the cost of energy assessment summarized in ES-5 below, also provides protection against operational difficulties that might otherwise reduce plant availability.

[31] This report has not attempted to quantitatively evaluate the costs or risks that ratepayers are being asked to take on, or to quantify the benefits that they will receive. Instead the paper outlines qualitatively how IGCC and the 3Party Covenant benefit ratepayers and quantifies the direct economic savings associated with 3Party Covenant financing. A comprehensive cost/benefit assessment is beyond the scope of the paper, but may be an appropriate future line of investigation.

[32]The cost risks to the ratepayer of a new IGCC plant would also be significantly diluted by the fact that the plant would constitute a small percentage of the total sources of power (generation and purchases) used by a utility. Typical large electric utilities in the U.S. have total sources of power that range between about 50 and 150 million MWh per year. (For example, in 2002 the total sources of power for Cincinnati Gas & Electric were 133 million MWh; Florida Power and Light, 105 million MWh; and PSI Energy, 63 million MWh (see EIA Form 861.) A new 550 MW IGCC facility would generate about 4 million MWh per year if operating at an 85 percent capacity factor. Therefore, in a worse case scenario, if the cost of energy from an IGCC facility ended up 20 percent more than the cost of energy of an alternative PC plant, it would represent a 0.5 to 1.6 percent increase in the overall cost of power procurement by the utility, due to the single plant’s relatively small share of the total sources of power.

Figure ES-6. Federal Budget Cost of 1 cent/kWh Support for 3,500 MW of IGCC under Different Policy Approaches



[1] PTC = Production Tax Credit equal to 1.0 cent/kWh of generation (10-year PTC program provides significantly less economic benefit than the other programs that provide about 1 cent/kWh over 30 years).
[2] Federal grant equal to 30 percent of total plant investment (equivalent to 0.96 cent/kWh of economic support for 30 years).
[3] Assumes 10 percent scoring of federal guarantees (equivalent to 1.06 cent/kWh of economic support for 30 years).

1. Payments by the Government to cover defaults and delinquencies, interest subsidies, or other payments; and
2. Payments to the Government, including origination and other fees, penalties and recoveries.

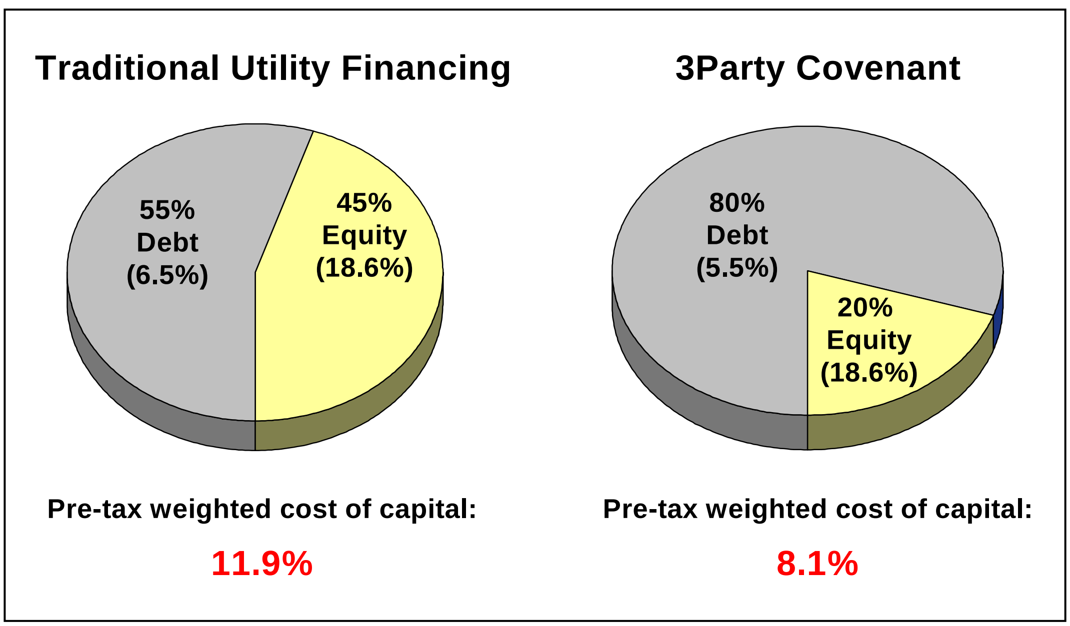
Payments by the Government are estimated based on the dollar amount guaranteed and the risk of loan default. Default risks are typically evaluated by Moody's or Standard & Poors. The risk of default provides for estimation of the expected payment (the risk of default times the amount guaranteed) to make the scoring determination. The Director of the Office of Management and Budget (OMB) is charged with making this determination, but may elect to delegate the OMB's authority to another agency. To the extent the rating agencies and OMB view the 3Party Covenant as reducing the risk of default by providing a state PUC approved revenue stream, the federal budget cost (scoring) of the loan guarantees should be reduced. If loan guarantees under the 3Party Covenant were scored at 10 percent of the principal amount guaranteed, then $5 billion of loan guarantees (enough for about 3,500 MW) would cost the federal budget $500 million.

This budget impact is significantly less than alternative grant or energy production tax credit based incentive programs. As illustrated in Figure ES-6, a one cent/kWh production tax credit provided over a 30 year period (approximately the same economic benefit as provided by the 3Party Covenant) for 3,500 MW of IGCC would cost the federal government $7.8 billion, or sixteen times more than the 3Party Covenant. If provided for only 10 years, the one cent/kWh production tax credit (providing the project significantly less economic benefit than the 3Party Covenant) would still cost $2.6 billion, or more than 5 times more than the 3Party Covenant. Similarly, if a 30 percent federal grant were offered to offset IGCC capital costs, the federal budget cost would be more than 3.5 times more than the budget cost of the 3Party Covenant. The 3Party Covenant loan guarantee approach is significantly less costly to the federal government than these alternative incentive approaches and has the advantage of addressing the major financial obstacles to deployment (e.g., capital availability) that would not be addressed by a production tax credit or grant program.[33]

The 3Party Covenant program reduces the cost of energy from an IGCC power plant approximately 17 percent. The cost of energy reductions result from:

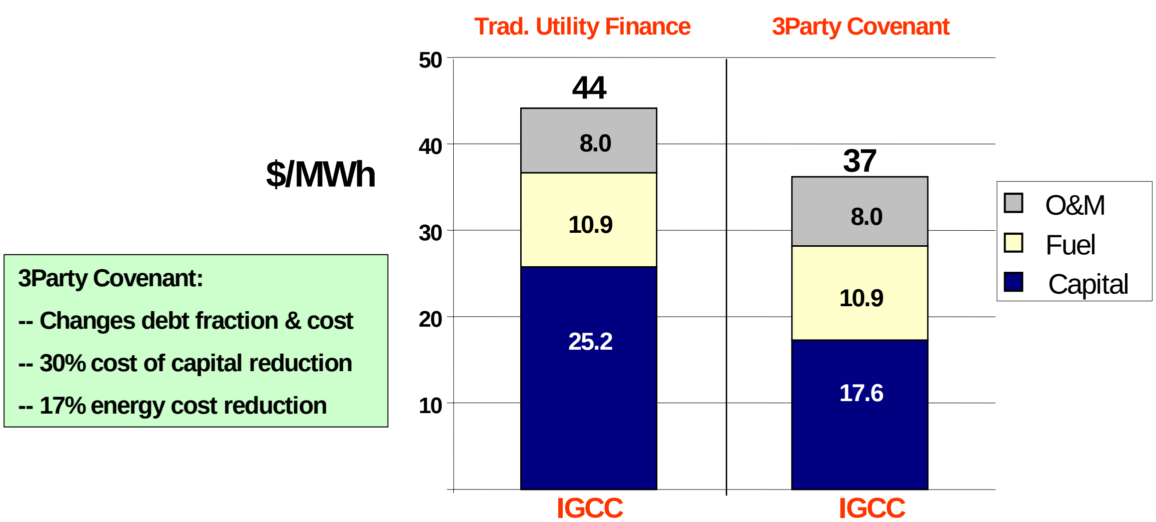
1. Providing for a significantly higher ratio of debt to equity than a traditional utility financing ratio (from 55/45 to 80/20 under the 3Party Covenant).
2. Lowering the cost of debt through the federal loan guarantee, which reduces

Figure ES-7. Cost of Capital Reduction under 3Party Covenant



[33] This is not to suggest that budget cost and capital availability are the only attributes that policy makers should consider. There may be other tradeoffs between a PTC and loan guarantee approach that policy makers may want to weigh, such as the requirements for administering the program and the risks associated with different approaches.

Figure ES-8. 3Party Covenant Impact on IGCC Cost of Energy



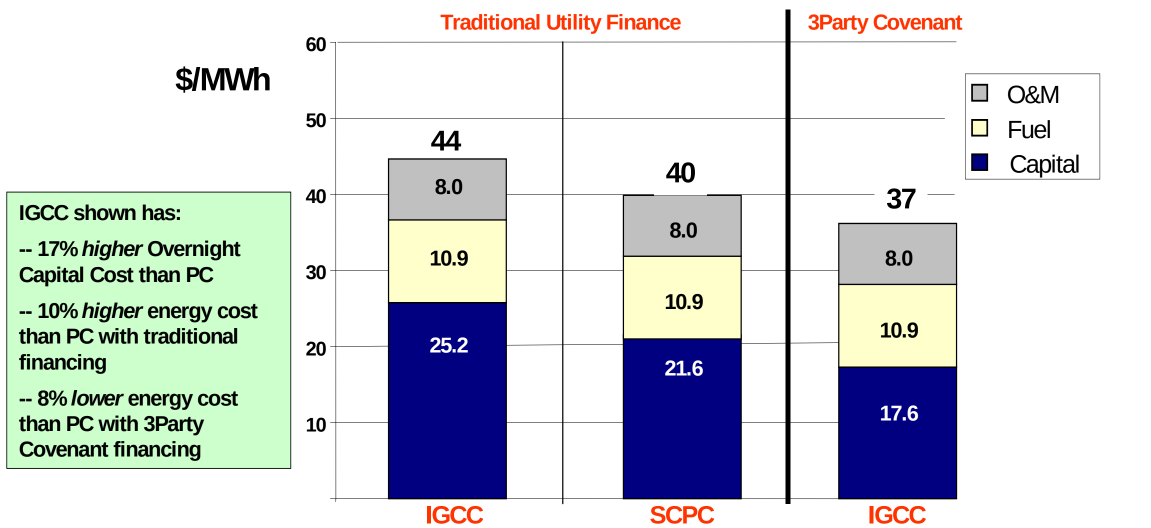
Overnight Capital Cost ($/kW)	$1,400	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25
Capacity Factor	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700
Debt Fraction	55%	80%
Debt Cost	6.5%	5.5%
Pre-Tax Equity Return	18.6%	18.6%

the interest charge from a typical 6.5 percent for a mid-grade utility bond to the 5.5 percent rate associated with a federal agency bond, in January 2004. Funding construction financing costs on a current basis by adding construction work in progress (CWIP) to the rate base and recovering these financing costs as they are incurred, rather than accruing these financing costs (which typically account for about 10 percent of Overnight Capital Costs) and recovering them as part of the capital investment.

As illustrated in Figure ES-7, these changes reduce the pre-tax, nominal weighted average cost of capital of an IGCC plant over 30 percent from about 12 percent (traditional utility financing) to 8 percent (3Party Covenant). Since the cost of capital accounts for over 60% of the total cost of energy in a capital intensive coal based PC or IGCC, this change in cost of capital (along with the reduction in construction financing costs) reduces the total energy cost about 17 percent.

The impact of the 3Party Covenant is demonstrated by comparing the cost of energy associated with a reference IGCC plant financed under a traditional utility financing scenario, with the same plant financed under the 3Party Covenant. As illustrated in Figure ES-8, the reference IGCC plant financed under traditional utility financing has a

Figure ES-9. IGCC Cost of Energy versus Super-Critical PC



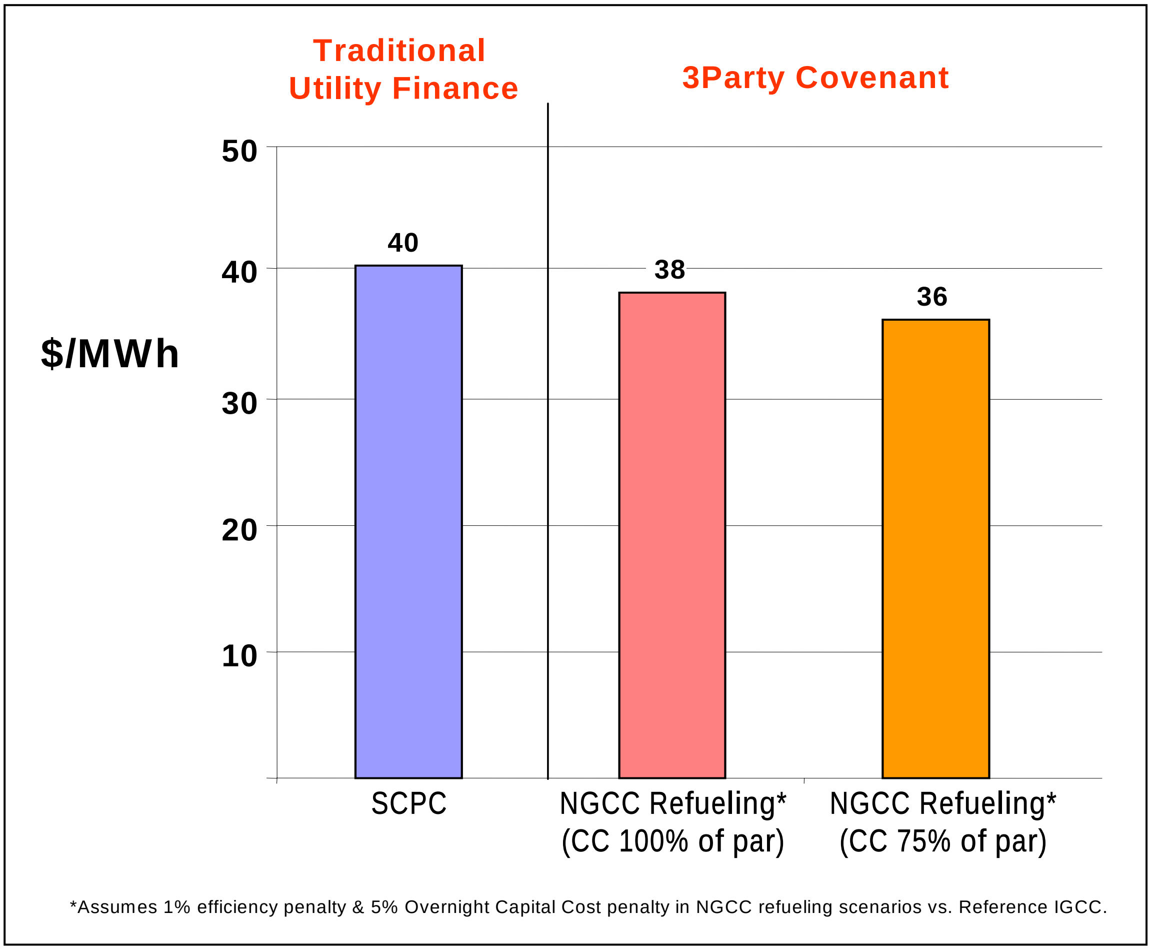
Overnight Capital Cost ($/kW)	$1,400	$1,200	$1,400
Fuel Cost ($/mmBtu)	$1.25	$1.25	$1.25
Capacity Factor	85%	85%	85%
Heat Rate (btu/KWh HHV)	8,700	8,700	8,700
Debt Fraction	55%	55%	80%
Debt Cost	6.5%	6.5%	5.5%
Pre-Tax Equity Return	18.6%	18.6%	18.6%

calculated cost of energy of 44 $/MWh, while the same plant financed under the 3Party Covenant has a cost of energy of 37 $/MWh. The 3Party Covenant reduces the cost of capital component of energy cost 30 percent and energy cost 17 percent.

Figure ES-9 illustrates how the 3Party Covenant affects the relative cost of energy of IGCC compared to PC. The figure illustrates the Reference IGCC plant assuming traditional utility financing and under the 3Party Covenant compared to a PC plant built with traditional utility financing. The figure illustrates that the Reference IGCC plant has a 17 percent higher Overnight Capital Cost than the PC plant, which results in a 10 percent higher cost of energy when both are financed traditionally. However, when 3Party Covenant financing is applied to the IGCC plant, its cost of energy is reduced to a level 8 percent below the PC plant.

Opportunities have recently emerged to create even more favorable IGCC economics by financing the refueling of distressed NGCC assets with coal gasification systems under the 3Party Covenant. Under the reference case IGCC, it is assumed that the gasifier island accounts for about 65 percent of the $1,400/kW EPC cost, or roughly $900/kW and that the combined cycle power block costs about 35 percent, or $500/kW. In a distressed NGCC refueling scenario, the combined cycle power block may be available at a significantly reduced price. If available for refueling at 75 percent of par, the cost is about $375/kW, and at 50 percent of par, it is $250/kW. If these costs are applied as the

Figure ES-10. Cost of Energy of NGCC Refueling under 3Party



combined cycle power block component of the IGCC EPC cost, the Overnight Capital Cost is reduced to $1,275/kW and $1,150/kW, respectively (well below the $1,400/kW reference case assumption).

In refueling scenarios, there is likely to be some inefficiency in design and construction of the gasification system and its integration due to retrofit requirements. For example, a $15/kW cost has been suggested by NETL for refitting the combustion turbine. Other costs might include the need for supplemental steam generation or site improvements. In addition, plant integration may be less than would be planned for a facility designed from the outset to be an IGCC, which may result in reduced efficiency. For this analysis, a five percent capital cost and one percent efficiency penalty is incorporated into the NGCC refueling scenarios to address these issues.

Figure ES-10 illustrates the cost of energy achieved in NGCC refueling scenarios assuming the combined cycle power block is contributed to the project at 75 percent of its original par value (assumed to be $500/kW). Figure ES-10 illustrates that combining 3Party Covenant financing and the potential cost savings associated with using existing distressed NGCC assets produces energy at levels below an all-new IGCC and at levels 10 percent below the reference PC plant built with traditional utility financing. Actual project savings will depend on the cost of the distressed asset to the project and the level of additional cost associated with retrofitting the combined cycle power block to work with a coal gasification system. For example, if the combined cycle power block were contributed to the project at 50% of par, the cost of energy would be about 14 percent below the traditionally financed PC, or $34.5/MWh.

ES-5. Implementation

Implementation of the 3Party Covenant requires federal legislation authorizing loan guarantees for qualifying IGCC projects. Consideration must be given to a number of implementation issues in developing legislation to ensure the program meets IGCC deployment objectives with minimal federal budget impact. Meeting deployment objectives will require determining the desired level of investment (in what timeframe), and ensuring that the economic and financial hurdles that have inhibited IGCC commercial deployment to date are adequately addressed. Section ES-7 below outlines recommended components of federal legislation for implementing the 3Party Covenant to stimulate 3,500 MW of IGCC deployment through authorization of $500 million of budget scoring appropriations to support $5 billion of federal loan guarantees.

The timing of 3Party Covenant implementation is dependent on enactment of federal legislation to establish a loan guarantee program. Proposed energy legislation debated by Congress in 2003 provided significant tax and loan guarantee incentives for clean coal technologies, including IGCC. Ongoing energy policy discussions and wide support for advancing clean coal technologies provide a window of opportunity for near term discussion and implementation. The sooner a program is put in place, the sooner the energy and environmental benefits of IGCC deployment (described in detail in Section 1 of this report) will be realized, a circumstance that should provide strong motivation for lawmakers to consider near-term legislative action.

Implementation of the 3Party Covenant also requires that states establish regulatory mechanisms for review, approval and recovery of IGCC project costs. Section 8 (Volume II) of this report, describes the status of state electric utility regulatory programs in three states with regulated retail electricity service (Indiana, Kentucky and New Mexico) and two states with competitive retail electricity markets (Ohio and Texas) to identify how the different regulatory programs affect 3Party Covenant implementation. Section 9 (Volume II) provides a model state regulatory mechanism for implementing the 3Party Covenant.

ES-6. Components of Federal Legislation for Implementing 3Party Covenant

The outline below describes recommended components of federal legislation to implement the 3Party Covenant. These components are designed to stimulate development of 3,500 MW of IGCC generation with federal loan guarantees of $5 billion. The program is targeted at stimulating deployment of IGCC technology, which is the focus of this paper. This or other incentive programs may be appropriate for IGCC and other advanced coal technologies.

<u>Purpose</u>

Establish a federal loan guarantee program that stimulates deployment of IGCC by reducing cost of capital, apportioning risk, and assisting with pre-development costs in order to:

- Support U.S. energy independence
- Promote homeland security
- Improve coal generation environmental performance
- Increase generation efficiency
- Refuel and revalue billions of dollars of financially distressed and underutilized natural gas combined cycle investments
- Reduce pressure on natural gas prices
- Provide affordable and reliable electricity supplies
- Position the U.S. as a global leader in advanced coal generation technology
- Minimize the burden to the federal budget

<u>Scope</u>

- $500 million appropriations to score up to $5 billion of federal loan guarantees for 3,500 MWs of base load capacity:
    - $450 million for scoring loan guarantees
    - $50 million revolving fund for pre-development engineering loans
    - Loan guarantees may be committed for a period of 10 years beginning with the first fiscal year the program is funded.
- Program shall be implemented through an accelerated rulemaking process to be completed within 12 months of enactment
- Program shall authorize the collection of application or other fees to cover administrative costs as well as insurance fees to the extent such fees are determined to be appropriate by the Secretary

Loan Guarantees

- Up to 80% of total plant Investment
- 30-year term, non-recourse, backed by full faith and credit of U.S. Government
- Owner contributes 20% equity investment

Qualifying Projects

- An IGCC or other coal-fueled power plant technology with the following performance characteristics:
    - Coal accounts for at least 75% of fuel heat input
    - In the case of IGCC, combustion turbine operates on syngas as primary fuel (natural gas or diesel may serve as an emergency back-up fuel only)
    - Design heat rate of 8,700 btu/kWh (HHV) or lower
    - New power plant, repowering of an existing coal power plant, or refueling of an existing natural gas combined cycle power plant
- Emissions Performance:
    - 99% sulfur reduction with SO_2 emission not to exceed 0.04 lb/mmBtu
    - NOx emissions not to exceed 0.025 lb/mmBtu
    - Particulate emissions from stack not to exceed 0.01 lb/mmBtu
    - 95% mercury emissions control
- Determination by DOE that the technology provides a technical pathway for CO_2 separation and capture and for the co-production of hydrogen slip-streams.
- To minimize federal budget scoring, qualifying projects shall have:
    - 3Party Covenant assured revenue stream through state PUC or other regulatory body providing upfront and ongoing regulatory determinations of prudence of project costs and approvals of pass-through of project costs (reflecting ongoing inclusion of approved capital investments in rate base and inclusion of approved operating costs in the cost of service, or reflecting purchased power costs incurred under a power purchase agreement) under federal and state enabling laws ("Regulatory Determinations"); or
    - Comparable credit (and budget scoring) as that provided by 3Party Covenant Regulatory Determinations, which might be created through insurance, industrial guarantees, or other credit enhancements.
- Projects shall include EPC contractor performance and delivery guarantees (full wrap) for project construction.
- Initial financing shall provide Line of Credit for additional draw of up to 15 percent of Capital Costs with an additional minimum matching equity contribution of 20 percent of the amount drawn.

- Secretary shall issue guarantees only for projects with budget scoring that does not exceed 10% of loan principal.
- Secretary shall develop criteria for issuing loan guarantee reservations (commitments prior to closing) for projects that have demonstrated feasibility and meet program qualifications

<u>Pre-development Engineering Loans</u>

- Non-recourse, interest-free loans shall be available for 75% of the cost of developing initial engineering and feasibility evaluations of potential projects
- Developer will be required to provide 25% cash match
- Loans not to exceed $5 million dollars
- Loans to be repaid out of long-term project loan disbursements and placed into a revolving loan fund
- Secretary shall develop criteria for selecting projects to receive Pre-development Engineering Loans, taking into account project timing, feasibility and ability to meet Project Selection Criteria (below)

<u>Project Selection</u>

- Secretary shall establish Project Selection Criteria, including consideration of the following elements:
    - Utilization of diverse coal supplies and types
    - Competitive electricity prices
    - Geographic diversity
    - Project feasibility
    - Financial strength of project
    - Environmental performance

Attachment 2

National Gasification Strategy Paper

National Gasification Strategy

Gasification of Coal & Biomass as a Domestic Gas Supply Option

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Dwight C. Alpern

Energy Technology Innovation Project
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May 2005 Revision

This paper is a revised version of the authors' January 2005 working paper. The update reflects adjustment of the equity return used in calculating levelized carrying charges and energy costs used in the report by reducing the modeled return from 18.6 percent to 11.5 percent. The update also includes some other minor changes, which reflect or result from the adjustment of the modeled equity return.

DISCLAIMER

EXECUTIVE SUMMARY

Natural gas provides 24 percent of the energy used by U.S. homes and businesses and is a vital feedstock for chemical, fertilizer, and other industries. Since 1999, natural gas prices in the U.S. have more than doubled,[1] adding about $70 billion annually to U.S. natural gas customers[2] and causing widespread adverse economic impacts, including high home heating bills, escalating commercial energy costs (affecting hospitals, schools, office buildings, and shopping centers), substantial job losses in chemicals, fertilizer, and manufacturing industries, and financial distress in the electric power sector.[3]

The root of the natural gas problem is that production in North America has hit a plateau and can no longer keep up with growing demand in the U.S. and Canada. As a result, the U.S. is facing a future with higher natural gas prices and a growing dependence on overseas imports of liquefied natural gas (LNG) for incremental supply. In December 2004, the Senate Energy and Natural Resources Committee, Chaired by Senator Domenici, requested “fresh ideas” to address the growing natural gas crisis in the U.S.

An option to supplement natural gas supply and reduce demand is for Congress to adopt the National Gasification Strategy to promote commercial investment in gasification technologies that manufacture gas from domestic coal, biomass, or petroleum coke. By providing federal loan guarantees and other incentives for industrial and electricity sector investments in gasification technology, the National Gasification Strategy could produce gas supplies equivalent to those expected from the Alaska Gas Pipeline (1.5 trillion cubic feet (TCF)), but in a more immediate time frame.

Loan guarantees (like the ones provided for the Alaska Gas Pipeline) are a preferred incentive approach because they can minimize federal budget costs. A $30 billion loan guarantee program for gasification would cost the federal budget approximately $3 billion spread over five years,[4] and could stimulate manufactured gas production equivalent to 1.5 TCF of natural gas. The manufactured gas could be produced for $4.0 per million Btu (mmBtu) and coal gasification power for 3.7 cents per kilowatt-hour (cents/kWh), well below current natural gas prices of $6 -7.00/mmBtu and natural gas power that costs over 6 cents/kWh.

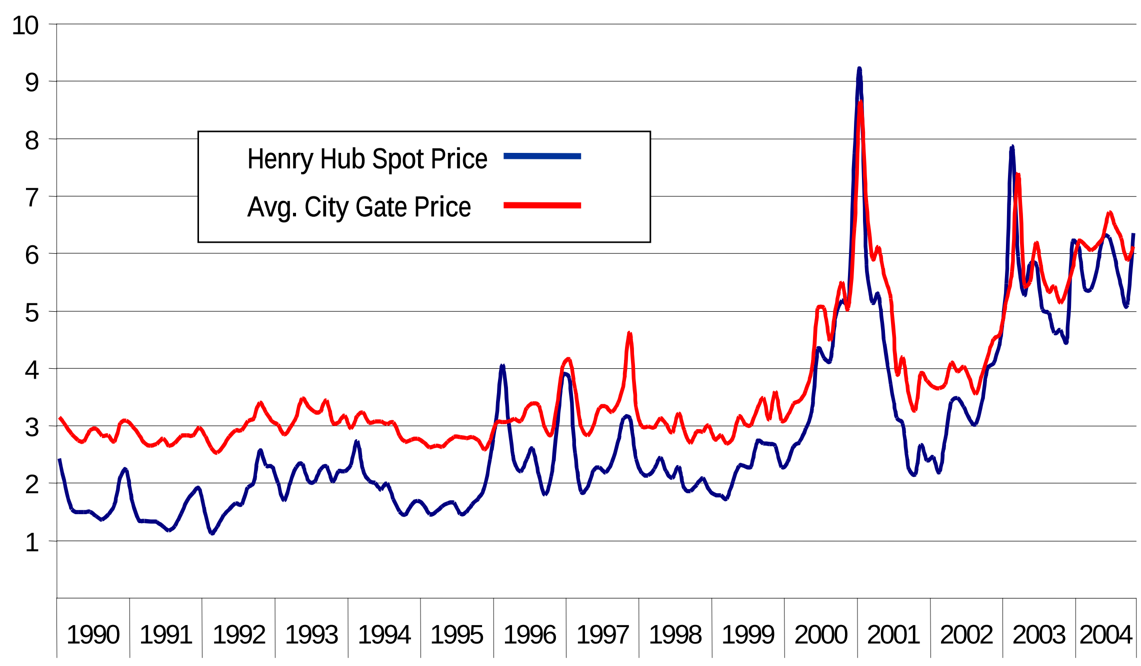
The National Gasification Strategy should also include funding for research, development, demonstration, and deployment of carbon capture and sequestration technologies that could leverage gasification investments under the program. Considering that every $0.50/mmBtu increase in natural gas prices adds about $10 billion in costs annually to U.S. businesses and consumers, investment in the National Gasification Strategy is justified to promote a more secure, predictable, and affordable national energy future.

U.S. NATURAL GAS CRISIS

For two decades (1980-1999), annual average wellhead natural gas prices in the U.S. remained between \$1.5/mmBtu to \$2.6/mmBtu.[5] However, in late 2000, gas prices began a steep rise, with December city gate prices reaching \$6.60/mmBtu and a spot market peak near \$10/mmBtu (Figure 1).[6] A combination of intense drilling activity and demand reductions (resulting from the high prices) brought prices partially back down by late 2001, leading many to assume that the 2000-2001 price increases were a short-term phenomenon. However, prices began to rise again in 2002 and continued to rise in 2003 and 2004. These sustained price increases led to a rethinking of past supply and price projections and a new understanding that supply constraints are likely to keep prices high for the foreseeable future. The National Petroleum Council noted in its September 2003 report:

> Current higher gas prices are the result of a fundamental shift in the supply and demand balance. North America is moving to a period in its history in which it will no longer be self-reliant in meeting its growing natural gas needs; production from traditional U.S. and Canadian basins has plateaued. Government policy encourages the use of natural gas but does not address the corresponding need for additional natural gas supplies. A status quo approach to these conflicting policies will result in undesirable impacts to consumers and the economy, if not addressed.[7]

Figure 1. Henry Hub & Average City Gate Natural Gas Prices 1990-2004.



Sources: Henry Hub Spot Price: Reuters, Wall Street Journal and Oil & Gas Journal; City Gate Price: EIA at: http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3m.htm

This fundamental shift in the supply/demand balance and the sustained rise in prices were not foreseen by industry or government forecasts prior to 2003. As late as 2002, most analysts agreed that expanding domestic natural gas production and Canadian imports would keep pace with growing demand and maintain wellhead prices below \$3.60/mmBtu through 2020.[8] For example, the average wellhead price projected for 2005 in the Annual Energy Outlook 2002 was \$2.60/mmBtu. However, wellhead prices in October 2004 were \$5.3/mmBtu[9] and are now expected to remain at that level through 2005, a level 106 percent higher than predicted in 2002,[10] and current estimates of 2005 production are 2.2 TCF below Energy Information Administration (EIA) estimates published between 1996 and 2002.[11]

Forecasters have now revised their natural gas price projections based on a new understanding that domestic production is unlikely to significantly increase to meet growing demand. The 2005 Annual Energy Outlook Reference Case projects the average delivered price of natural gas to remain above \$5.5/mmBtu through 2025[12] and that 96 percent of the incremental supply needed to meet growing U.S. demand must come from overseas imports of liquefied natural gas (LNG) (72 percent) and Alaska (24 percent).[13] The continuation of historically high natural gas prices and the potential for U.S. dependence on imports from countries such as Algeria, Malaysia, and Qatar for needed supply are cause for serious concern.

Impact of High Natural Gas Prices

High natural gas prices are seriously undermining the economic competitiveness of many U.S. industries. For example, the chemical industry, which is the largest industrial consumer of natural gas in the U.S., estimates it has lost \$50 billion in business to foreign competition and more than 90,000 jobs since 2000 due to high natural gas prices.[14] Similarly, the fertilizer industry, where 70 to 90 percent of the cost of producing ammonia for fertilizer is the cost of natural gas, reported in 2003 that 11 ammonia plants representing 21 percent of U.S. capacity had already been closed, that only 50 percent of the remaining U.S. capacity was operating, and that two major U.S. fertilizer producers had already filed for bankruptcy.[15] A chief executive officer of a leading fertilizer company stated in remarks to the Secretary of Energy in November 2003:

> If we are to prevent further decimation of the U.S. industry, we must enact policies that stabilize the supply/demand balance for natural gas. I can't overemphasize to you the urgency of the need to act decisively and immediately on this issue. U.S. natural gas markets are in a full-blown state of emergency.[16]

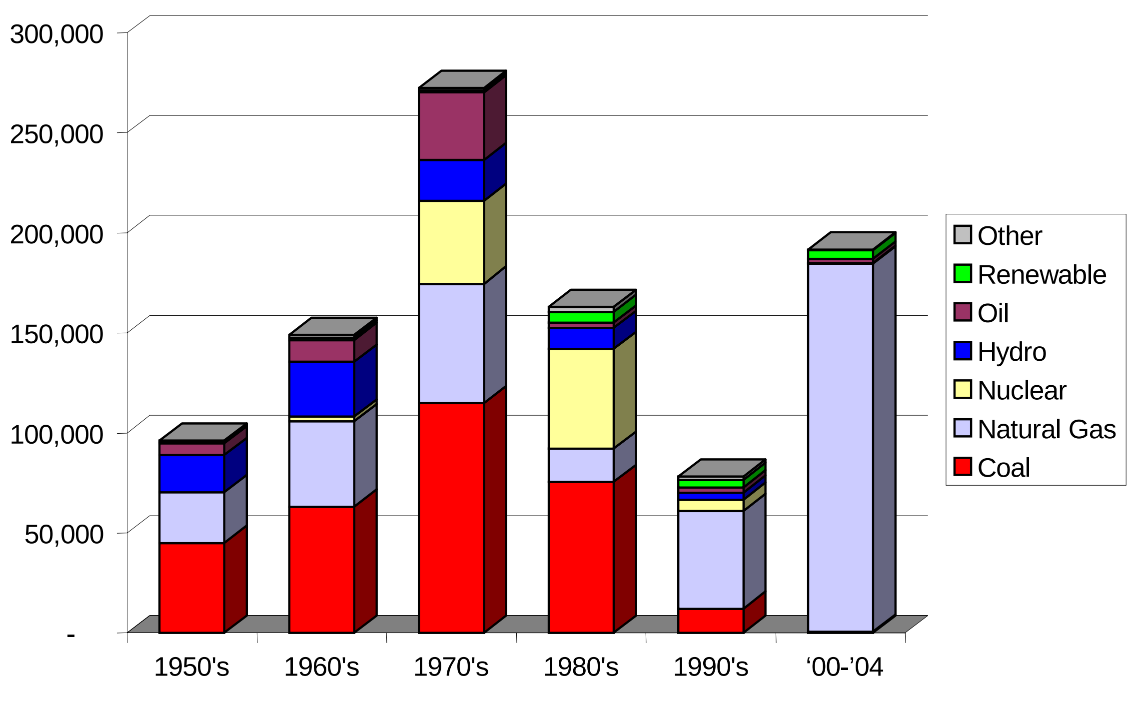
Despite this plea, natural gas prices continued to rise in 2004.

Another impact of the high prices has been to increase significantly the cost of generating electricity with natural gas. Low natural gas price assumptions in the late 1990's (based on industry and government projections indicating prices would remain at historic levels) led to an unprecedented surge in the construction of natural gas-fired power plants. Since

1995, over 230,000 mega-watts (MW) of new natural gas generating capacity came on line, including 184,000 MW since 2000, which is more natural gas capacity in four years than the total capacity (all fuels) added in any decade except the 1970's (Figure 2).

At current prices, operating this new fleet of natural gas generation is uneconomic most of the time. Consequently, natural gas power plants, specifically natural gas combined cycle (NGCC) facilities built to sell power into deregulated electricity markets, are operating at very low capacity utilizations and are in widespread financial distress. Some of these facilities financed with non-recourse debt have already been turned over to banks, and other facilities have been sold for less than 20 percent of their original cost.[17] NGCC facilities built by utilities in regulated electricity markets and approved by state utility commissions are still operating at higher capacity factors and passing high generating costs through to electric customers.[18] Thus, in some areas, high natural gas prices are forcing residential and business consumers to take a one-two punch from high natural gas and electricity prices.

Figure 2. U.S. Capacity Additions by On-line Date (MW)



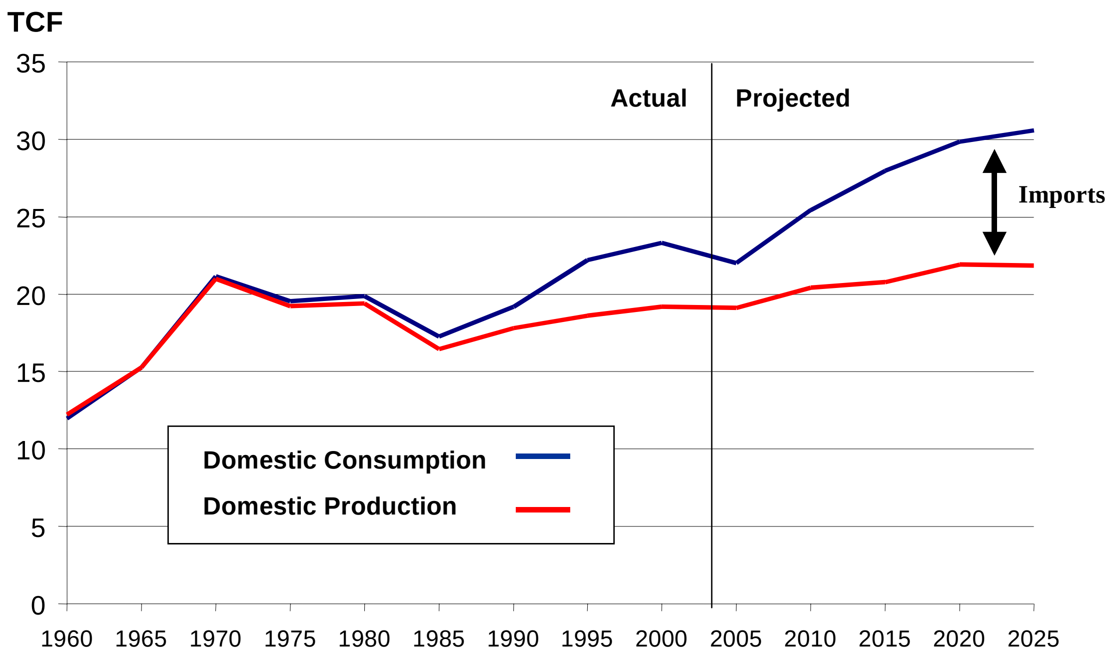
Sources: EIA, Form 860 for 2003; EIA, Electric Power Monthly, Nov. 2004, Table ES-3.

Natural Gas Supply Outlook

Historically, natural gas supplied to U.S. markets has come almost entirely from domestic production in the lower 48 states (both on and offshore) and, beginning in about 1985, from imports from Canada and Mexico. However, over the next 20 years, U.S. natural gas production from on and offshore wells in the lower 48 states is expected to grow by only 5 percent and net imports from Canada and Mexico are expected to decline slightly as those countries consume more for their own use.[19] At the same time, the share of U.S. imports is expected to increase significantly as domestic production lags further and further behind domestic consumption (Figure 4).

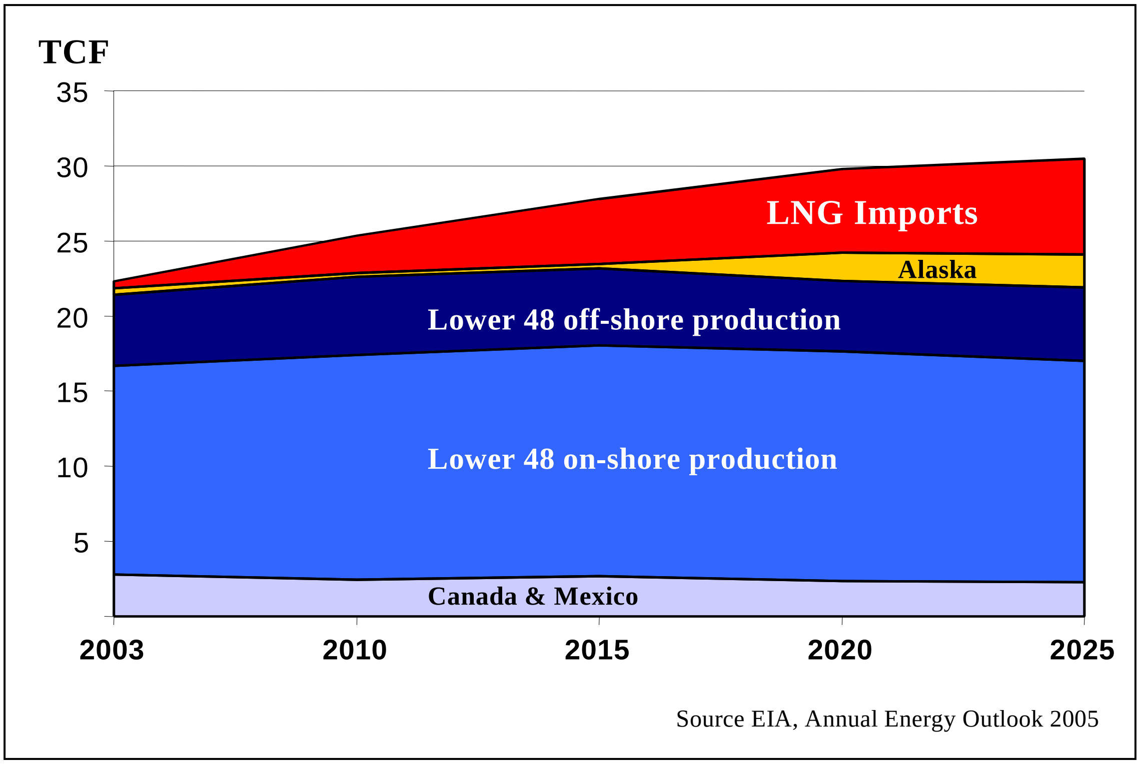
Natural gas production in the U.S. faces a constant battle to replenish (and expand) supplies by drilling new wells, which is evidenced by the fact that 28 percent of natural gas wellhead capacity in the U.S. is from wells that are less than a year old and 53 percent is from wells less than 3 years old.[20] Only the constant drilling of new producing wells allows domestic natural gas production to remain stable. Most analysts believe that domestic production has either already peaked, or will peak in the next decade before beginning a gradual decline.[21] The difficulty of expanding domestic production is illustrated by recent trends, with the number of wells drilled increasing significantly in response to higher prices but overall natural gas production remaining flat.[22]

Figure 3. Domestic Natural Gas Production is not Keeping Pace with Demand.



Sources: Historic data: EIA, Annual Energy Review 2003, Table 6-1; Projections: EIA, Annual Energy Outlook 2005, Table A-14.

Figure 4. Projected U.S. Natural Gas Supply



Due to the stagnation of domestic production, incremental supplies needed to meet growing demand are expected to come from additional production and pipeline capacity to deliver natural gas from Alaska (24%) and from the development of significantly expanded LNG terminal capacity to import gas (72%) from overseas (Figure 5).

Alaska Natural Gas Pipeline

In 2004, legislation was enacted to support construction of the Alaskan Gas Pipeline. The Alaska Gas Pipeline is expected to cover 3,500 miles and be completed around 2015.[23] When completed, it is expected to deliver 1.5 TCF per year of natural gas from Alaska, which one study estimated would reduce natural gas costs by about $0.50/mmBtu.[24] Pipeline construction is expected to cost about $20 billion.

Legislation enacted as part of the 2004 military spending bill established an 80% (not to exceed $18 billion) loan guarantee program to support and help finance the pipeline development. The legislation also includes provisions for expedited Federal Energy Regulatory Commission (FERC) permitting approvals (including putting FERC in charge of the Environmental Impact Statement required by the National Environmental Policy Act) and enhanced federal coordination.[25] In addition, separate legislation passed as part of the American Jobs Creation Act of 2004 allows for certain Alaska pipeline property to be treated as seven-year property and provides a tax credit for the cost of a needed gas conditioning plant on the North Slope of Alaska to process gas before it goes into the pipeline.[26]

LNG Terminal Expansion

LNG imports are projected to account for 72 percent of the incremental natural gas supplied to the U.S. between 2003 and 2025, raising the LNG share of total supply from less than 3 percent to 21 percent by 2025.[27]

There are currently four LNG import terminals in the U.S.[28] All four terminals were operational in 2003 for the first time since 1981 and supplied a record 507 Bcf of natural gas to U.S. markets.[29] The vast majority of the LNG was supplied from Trinidad and Tobago, which accounted for 75 percent of LNG exports to the U.S. The other suppliers were Algeria, Nigeria, Oman, Malaysia, and Qatar.[30]

Three of the existing LNG terminals have announced expansion projects that would approximately double LNG import capacity to about 1.7 TCF per year by 2008. In addition, the Energy Information Administration has tracked at least 35 LNG terminal proposals to supply North American markets. Several proposals are currently being considered by regulators, and at least three projects have been approved by FERC (one on-shore project) and the Maritime Administration (two off-shore facilities). Most LNG proposals face substantial public opposition that can hinder permitting and development.

LNG terminals cost between $400 and $600 million to construct and require multi-billion dollar upstream liquefaction investments to prepare the LNG for shipment to the U.S. A number of companies have announced intent to make these investments overseas.[31]

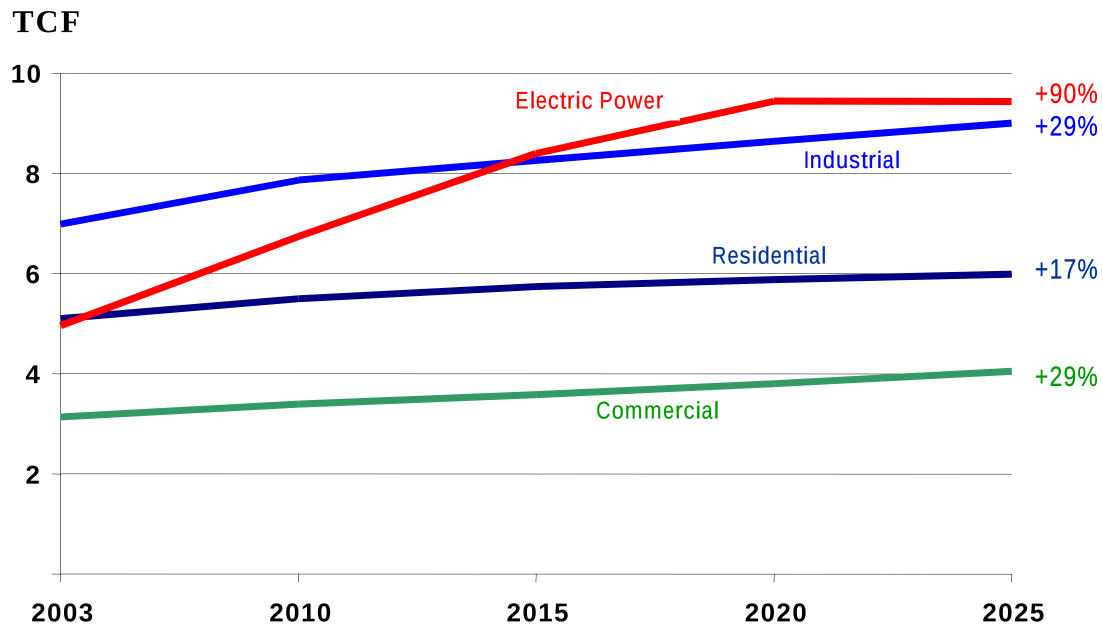
The growth of LNG imports is expected to play a major role in expanding natural gas supplies to meet growing demand in the U.S. However, the ability for LNG to fill this role remains uncertain and will be highly dependent on permitting and public acceptance, as well as the successful construction and safe operation of new domestic import terminals and overseas liquefaction facilities.

Electric Sector Natural Gas Demand Growth

In 2004, the U.S. consumed 22 TCF of natural gas. By 2025 demand is projected to grow 41 percent to 31 TCF. Demand growth is expected in all sectors, but demand from electric generators is expected to grow the fastest, increasing 90 percent by 2025 (Figure 3).

Beginning around 1997, electric generator natural gas demand growth began to accelerate as new natural gas-fired power plants came on-line. Between 1997 and 2004, demand from electric generators grew 1.1 TCF, or 27 percent, while natural gas demand from all other sectors decreased 1.8 TCF, or 10 percent (with industrial demand declining 16 percent).[32]

Figure 5. EIA Projected Natural Gas Consumption by Sector



Source EIA, Annual Energy Outlook 2005

Demand from the electric power sector is currently about 5.3 TCF (25 percent of total demand), but the existing fleet of natural gas power plants, particularly NGCC plants in deregulated markets, are operating well below their design capacities. The underutilization of these plants creates a demand overhang estimated to be 3.3 TCF and creates the potential for significant increases in natural gas use from the electric power sector without any additional capital investment.[33] This also indicates that any short to mid-term increase in natural gas supply (until the 3.3 TCF overhang demand is eliminated) will likely be absorbed by the electric power industry at prices exceeding those which other U.S. industries can afford to pay, resulting in additional job losses as those industries continue to move overseas where energy prices are lower. To help U.S. industry in the short to mid-term, natural gas demand must also be reduced by a combination of energy conservation and substitution of natural gas with gas produced from domestic feedstocks such as coal, petroleum coke, or biomass via gasification.

It has now become clear that under business as usual, North American natural gas production will not be able to keep up with projected demand growth (especially from power generation), which will keep pressure on prices and require significant LNG import expansions for incremental supply. Federal intervention to stimulate additional supply and ease demand pressure by expanding commercial gasification is a prudent national response to help domestic industry and improve natural gas affordability and security.

NATIONAL GASIFICATION STRATEGY

Gas supplies in the U.S. can be significantly enhanced by manufacturing gas from coal, biomass, and petroleum coke using commercially available gasification technologies. Federal incentives to stimulate investment in these technologies are critical if they are to come on line in substantial enough quantity to have a significant near-term impact on the natural gas supply/demand balance in the U.S. An aggressive but viable target for the National Gasification Strategy is to produce the equivalent of 1.5 TCF of natural gas per year within 10 years. This is an amount equivalent to the supply expected from the Alaska Gas Pipeline beginning around 2015. The supply from gasification could begin to come on-line in 5-7 years, providing a mid-term supply bridge to Alaska Gas Pipeline completion. Achieving 1.5 TCF of domestic gas production from gasification would require approximately $37 billion of capital investment in on-site gasification plants across the country (See Appendix A calculation).

The discussion below briefly describes gasification technology and its potential use in the industrial and electric power sectors, explains the federal budget and financing benefits of federal loan guarantees for stimulating investment, and recommends the National Gasification Strategy, which provides:

- Loan guarantees and other incentives to stimulate investment in gasification plants that produce synthesis gas for industrial and electrical use equivalent to 1.5 TCF of natural gas; and
- Funding for research, development, demonstration, and deployment of technology to capture and store carbon dioxide (CO_2) from gasification plants.

<u>Gasification Technology</u>

Gasification is the partial oxidation of a solid or liquid fuel feedstock to manufacture a gaseous product (synthesis gas or "syngas") made up of predominantly hydrogen (H_2) and carbon monoxide (CO).[34] Impurities, such as particulates, sulfur, nitrogen, and volatile mercury are easily removed from the syngas using commercially proven systems to produce synthesis gas that is almost as clean as natural gas. Synthesis gas has a lower heating value than natural gas,[35] but can be readily substituted in many industrial processes and in the generation of electricity with modern gas turbines. Synthesis gas can also be converted to synthetic natural gas (methane) using commercially-available methanation catalysts.[36]

According to a recent survey by the Gasification Technologies Council (GTC), there are 385 gasifiers in operation at 117 projects worldwide.[37] These gasifiers are used to produce liquid fuels in South Africa (Sasol facility), chemicals in the U.S. (Kingsport facility), electricity in the U.S., Europe and Japan (Polk, Wabash River, Puertollano, Buggenum, and Negishi facilities),[38] methane in the U.S. (Great Plains facility) and ammonia fertilizer in China and India. There are several different commercial gasifier designs available, including systems from GE Energy,[39] ConocoPhillips,[40] Shell,[41] Lurgi, and Noell. Each of these systems has been proven in commercial use around the world.

When a gasification plant is combined with a combined cycle power block to produce electricity, the process is called integrated gasification combined cycle (IGCC). The existing fleet of natural gas combined cycle (NGCC) power plants (over 100 GW) offers the potential for deploying gasification technology to refuel those plants to generate electricity at reduced cost. About 40 to 45 percent of the cost of an IGCC facility is the combined cycle power block, so using existing, underutilized NGCC infrastructure for the development of IGCC facilities could provide for significant cost savings. The conversion of NGCC facilities to utilize coal or other gasified fuels would also directly reduce natural gas demand.

Gasification also can be used to produce process fuel feedstocks, heat, steam, and electricity for a variety of industrial processes that currently use natural gas. For example, Eastman Chemical has successfully operated a GE Energy gasifer at its Kingsport, Tennessee facility since 1983 as the only source of gas for its chemical processes to produce film and other acetyl-based products. Similarly, Sasol operates one of the oldest and largest gasification operations in the world in South Africa, where high-ash coal is gasified with Lurgi gasifiers to produce a variety of liquid fuels and chemical products. Several players in the chemical industry are looking at new production technology to utilize syngas for the production of large volume commodity chemicals that are currently based on natural gas liquids. In addition, China is currently constructing nine gasification systems for ammonia fertilizer production based on the Shell technology.

Gasification technology is also important because it offers substantial environmental benefits in the use of coal. Direct combustion of coal (in pulverized coal power plants, for example) creates significant air emissions of pollutants regulated by the U.S. Environmental Protection Agency, including nitrogen oxides (NOx), sulfur dioxide (SO_2), particulates, and mercury (Hg). Unlike combustion processes that rely on combustion or post-combustion controls to reduce emissions, gasification cleans up the gas prior to combustion when there is a greater concentration of pollutants, lower mass flow rate, and higher pressure than is present in flue gas after combustion. Therefore, emissions control through syngas cleanup in gasification processes is generally more cost effective than post combustion treatments to achieve the same or greater emissions reductions.[42] Gasification facilities also use significantly less water and produce less solid waste than pulverized coal power plants.

Perhaps the most significant environmental benefit of gasification is that it provides a technical pathway for addressing carbon dioxide (CO_2) emissions. The National Commission on Energy Policy underscored the importance of gasification and IGCC technology for addressing CO_2 stating:

> Coal-based integrated gasification combined cycle (IGCC) technology, which—besides having lower pollutant emissions of all kinds—can open the door to

> economic carbon capture and storage, holds great promise for advancing national as well as global economic, environmental, and energy security goals. The future of coal and the success of greenhouse gas mitigation policies may well hinge to a large extent on whether this technology can be successfully commercialized and deployed over the next 20 years.[43]

By adding water-gas shift reactors and physical absorption processes to the syngas treatment system (processes that are commercially proven in industrial applications), CO_2 can be removed from syngas (and pure hydrogen produced) prior to combustion. Several studies have shown this to be a more cost-effective approach to CO_2 capture with proven technology than post-combustion CO_2 capture on conventional coal combustion technologies.[44]

Carbon-neutral biomass gasification technology is close to being ready for deployment. Much of the major benefit will come from gasification technology using spent pulping liquors, which are by-products of pulp and paper manufacturing operations. The syngas produced from the organic lignin in the spent pulping liquor is similar in composition to that produced coal or petroleum coke, and would come from a renewable source of energy that is carbon-neutral with regard to greenhouse gas emissions. An independently-reviewed study in 2003 estimated that spent pulping liquor and wood residuals gasification could potentially produce 25 Gigawatts of electric power by the year 2020.[45]

Incentives to stimulate gasification investment will create gasification infrastructure that can serve as a foundation to research, develop, demonstrate, and deploy carbon capture and storage technologies. For example, a commercial coal gasification plant could sell a percentage of syngas manufactured to a federally financed research project, which could then test a variety of technologies to separate CO_2, operate turbines and fuel cells on hydrogen-rich fuel, and store CO_2 in geologic formations. The research projects should be funded separately from the commercial gasification investments and user costs. This concurrent approach—incentives for gasification technology deployment and separate funding for carbon capture and storage demonstration and deployment—is consistent with recommendations from the National Commission on Energy Policy, which proposes a $4 billion program over ten years to stimulate IGCC deployment and $3 billion over ten years for commercial-scale demonstration of geologic carbon storage.[46] While analyzing the costs of capturing and storing incremental CO_2 emissions from converted units was beyond the scope of this paper, this option is worth evaluating, considering the benefits it would provide in reducing gas demand, providing practical experience with carbon capture and storage, and enabling the program to be carried out without an increase in CO_2 emissions.

Gasification is an established technology worldwide that offers the potential for supplying gas and reconciling coal use and environmental protection. Its application for industrial processes and power production in the U.S. has been modest due to historically low natural gas prices and the expectation that natural gas would be available for the foreseeable future at these low prices. The recent rise in natural gas prices has begun to stimulate commercial interest in gasification, but commercial development and utilization is likely to be a slow process that takes many years as companies, investors, and utility regulators become familiar with the technology. Government incentives to kick-start gasification deployment are required if it is to play a significant role in helping stabilize the natural gas supply/demand imbalance in the next decade.

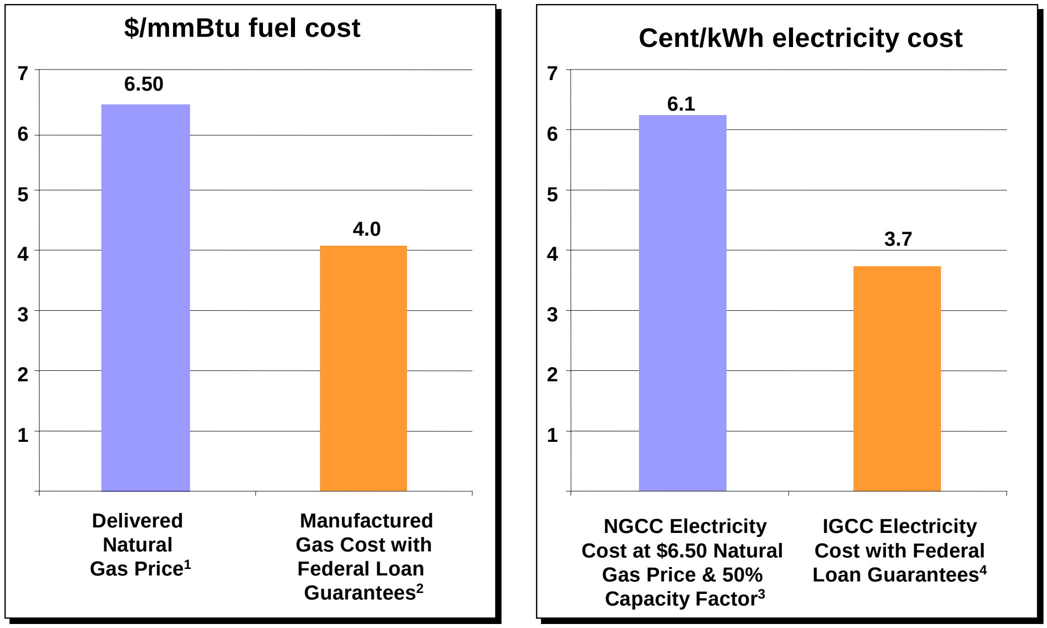
Loan Guarantees for Gasification

The federal government has a number of policy levers that could be incorporated in the National Gasification Strategy to stimulate investment in gasification technologies. The most significant policy options include credit financing support (loans, loan guarantees, performance guarantees, or lines of credit), tax incentives (investment tax credits, production tax credits, or accelerated depreciation treatment), or direct grants. As noted in the recent National Commission on Energy Policy report that recommends federal incentives to stimulate gasification investments, different incentives can be appropriate depending on the type of developer and development circumstances, suggesting that a suite of incentives may provide for the broadest participation.[47] At the same time, however, the federal budget impact of different approaches is a vital consideration given the current deficit and the focus in Washington on less, not more government spending. It is for this reason that loan guarantees provide a particularly attractive policy option for a National Gasification Strategy. Loan guarantees serve to provide access to capital markets, improve project economics, and minimize federal budget impacts.

A report by Rosenberg, et al.[48] describes how coal gasification power plants (IGCC) could be made commercially viable if utilities, state public utility commissions, and the federal government join together (an arrangement referred to as the "3Party Covenant") to finance a fleet of plants. Federal loan guarantees allow higher leverage and provide for lower cost debt, thereby reducing the cost of capital by 30%.[49] These savings can be passed on to industrial and residential customers in return for state public utility commissions (or municipal utilities in the case of public power) guaranteeing revenue to recover costs and prevent default on federally financed loans. Coal gasification power plants financed with federal loan guarantees as part of the 3Party Covenant would yield lower price power than conventionally financed new pulverized coal or natural gas plants operating in today's natural gas markets.[50]

Loan guarantees also enable debt investors to focus primarily on the federal guarantee to secure their investment rather than uncertain project economics and technology risks of an advanced technology deployment. Consequently, raising capital for a project becomes easier and less expensive for most developers, because debt investors protected by the federal guarantee can learn to become comfortable with technology and project risks in the future.

Figure 6. Cost of Manufactured Gas and IGCC Electricity with Loan Guarantees



Notes:
[1]YTD 2004 avg. electric generator natural gas price through August is 5.90 lb/mmBtu, see EIA: http://tonto.eia.doe.gov/dnav/ng/hist/n3045us3m.htm.
[2] See Appendix A for cost calculation. Assumes $475/MWth total plant investment (including construction financing), 9.4% capital charge rate with loan guarantees that includes 10% owners cost, 90% gasifier capacity factor, $1.25/mmBtu fuel price, 75% gasifier efficiency, and O&M of 4% of capital cost.
[3] NGCC cost of energy calculated based on $510/kW overnight capital, 16.9% capital charge that includes 10% owner's cost, 50% plant efficiency, $6.60/mmBtu gas, 50% capacity factor, and 0.25 cent/kWh O&M.
[4] See Rosenberg et. el. , *Deploying IGCC in this Decade with 3Party Covenant Financing,* May 2005 Revision, pg. 14. Calculated based on $1,400/kW overnight capital, 9.4% capital charge with 10% owner's cost, 85% IGCC capacity factor, $1.25 fuel cost, 39% IGCC efficiency, 0.80 cent/kWh O&M.

In the case of refueling existing natural gas combined cycle plants,[51] Independent Power Producer owners are generally not in a financial position to invest $500 million to $1 billion to construct gasification plants as a supply option. Federal credit support and upfront utility regulatory approval are necessary to enable a portion of this huge fleet of high natural gas demand plants to convert to gasification. Under the financing and regulatory proposal presented in the report by Rosenberg, et al., it is estimated that manufactured gas could be produced for $4.0/mmBtu and power could be produced for 3.7 cents/kWh, well below current gas prices of $6 -7.00/mmBtu and natural gas power that costs over 6 cents/kWh (Figure 6) (See Appendix A calculations).

Critical to the federal budget cost of any loan guarantee program is how the federal guarantee is secured. The budget cost of federal loan guarantees is governed by the Federal Credit Reform Act of 1990 (FCRA), which makes commitments of federal loan guarantees contingent upon prior budget appropriations ("budget scoring") of enough funds to cover the estimated present value cost of the guarantees. The present value cost is estimated based on the dollar amount guaranteed and the risk of loan default, which is typically evaluated by rating agencies and the Office of Management and Budget (OMB). Without any credit to protect the guarantee, the scoring cost will be based strictly on project risks, making the program more risky and expensive for the federal government.

The alternative is to secure strong credit enhancement to substantially mitigate default risks and protect the federal guarantor, which reduces the federal budget scoring and program cost.

The 3Party Covenant mitigates loan default risk by establishing an assured revenue stream to service debt obligations through utility rate determinations. For the electric power sector, this type of revenue stream can be created through a state public utility commission or other ratemaking body (e.g., a municipality or rural electric cooperative) providing up-front and ongoing determinations of prudence and approvals of timely pass-through of project (or power purchase agreement) costs to ratepayers. This is the mechanism recommended under the 3Party Covenant to provide revenue certainty to reduce the risk and budget scoring cost of a federal loan guarantee program. Under this program, the federal risk is only that the state assurances unravel, which is why a low budget scoring of 10 percent or less is expected. With 10 percent budget scoring, if a one billion dollar loan is guaranteed, the cost scored to the federal budget would be $100 million.

In the case of industrial gasification projects, strong credit (and low budget scoring) could also be accomplished with corporate guarantees, off-take agreements with creditworthy entities, insurance, or other credit enhancements. The key factor is ensuring that the federal risk is mitigated sufficiently to reduce the budget scoring to an acceptable level, such as 10 percent or less of the loan principal. At this level, a loan guarantee program will be very cost effective for the federal government and enable a gasification incentive program to have a substantial impact in producing additional gas supply and easing natural gas demand at reasonable federal cost.

It should be noted here that the Alaskan Gas Pipeline legislation specifically determined that the $18 billion of loan guarantees would *not have to provide credit enhancement.*[52] If the Congress decided to accept similar risks under the National Gasification Program, the level of credit enhancement could be specified at lower levels than those recommended here, but budget costs would then increase.

Incentives vs. Regulation

In the 1970’s after the Arab Oil Embargo, Congress enacted two regulatory programs to respond to natural gas shortages—the Fuel Use Act and the Coal Conversion Program. The Fuel Use Act prohibited utilization of natural gas in certain power plants and the Coal Conversion Program sought to convert, back to coal, natural gas electric generators that had previously used coal. Both programs had the unintended consequences of favoring coal-based generation without addressing resulting emissions of high polluting coal operations.

The National Gasification Strategy, on the other hand, advances deployment of the most advanced clean coal technologies and funds research, demonstration, and deployment of

CO_2 sequestration technologies. The National Gasification Strategy is based on government incentives to stimulate investment rather than regulatory mandates.

Recommended National Gasification Strategy Legislation

It is recommended that Congress enact the National Gasification Strategy to manufacture the equivalent of 1.5 TCF of natural gas per year, using domestic coal, biomass, and petroleum coke. The National Gasification Strategy should be targeted to stimulate gasification investments to substitute for natural gas demand from both industrial and electric power users and needed research, development, demonstration, and deployment of CO_2 sequestration options, and include the following elements:

- $3 billion authorization and appropriations ($600 million per year for five years) for federal budget scoring and authorization of $30 billion of loan guarantees for industrial and electric sector gasification projects;
- Loan guarantee program requirements:
    - Qualification for guarantees contingent on owner establishing strong credit support to minimize federal government risks and ensure federal budget scoring of 10 percent (or less) of loan principal. (the 3Party Covenant with state public utility commission or other rate-making body would qualify);
    - Administered by the Secretary of Energy, who shall promulgate regulations implementing the program within 12 months of the date of program enactment;
    - Loan guarantees available to cover up to 80% of total investment in each project, provided that the project owner(s) contributes at least 20 percent equity to the project;
    - Environmental conditions for power generation projects:
        - 99% removal (including any fuel pretreatment) of sulfur with total sulfur dioxide emissions not to exceed 0.04 lb/mmBtu.
        - 95% removal (including any fuel pretreatment) of mercury
        - Nitrogen oxides emissions not to exceed 0.025 lb/mmBtu.
        - Total particulate emissions not to exceed 0.01 lb/mmBtu.
    - Priority given first to projects that will start up operations by December 31, 2009 and then to projects that will commence construction by December 31, 2009.
- Consideration of investment tax credits, tax provisions for accelerated depreciation treatment, and performance guarantees for gasification investments to ensure broader participation;
- $1 billion in grants or other incentives to support research, development, and demonstration of technologies for the capture and storage of CO_2 from gasification facilities and demonstration of biomass gasification technology;
- $2 billion in tax credits, grants, and loan guarantee scoring to support commercial deployment of carbon capture and storage technologies on gasification facilities.

(More details of the program are provided in Appendix B “Legislative Concepts.”)

CONCLUSION

Natural gas production in North America has hit a plateau and can no longer keep up with growing demand in the U.S. As a result, the U.S. is facing a future with higher natural gas prices and a growing dependence on LNG imports for incremental supply. The National Gasification Strategy to manufacture synthesis gas from coal, biomass, and petroleum coke can provide additional domestic gas supply and ease natural gas demand to help alleviate price pressure and allow American industry to remain competitive. Federal loan guarantees backed by assured revenue streams, off take contracts, or corporate credit to substantially mitigate loan default risk, provide a cost-effective vehicle for government support for gasification technology investment. As part of a National Gasification Strategy, a $30 billion federal loan guarantee program, coupled with targeted tax incentives, will stimulate early industrial and electric sector investment in gasification projects across the country to manufacture the equivalent of 1.5 TCF per year of domestic gas supply. To address the expanded CO_2 emissions when coal or petroleum coke is the fuel, a concurrent research, development, demonstration, and deployment program focused on CO_2 capture and storage technology should be an integral part of the National Gasification Strategy.

APPENDIX A: SYNGAS COST CALCULATION

Plant Summary		
Gasifier Capacity (MWth)		1,000
IGCC Capacity (MWe)		500
Gasifier Syngas output (mmBtu/hour)		3,413
Gasifier Capacity Factor		90%
Annual syngas output (mmBtu)		26,908,092
IGCC Capital Cost		
Capital Cost ($/kWe)		1,596
Total Capital		798,000,000
Gasifier Capital Cost		
Capital Cost ($/kWth)	$	475
Total Capital	$	475,000,000
Capital Charge Rate		0.094
Annual Capital Cost	$	44,550,250.0
Syngas Capital Cost ($/mmBtu)		**1.66**
Fuel Cost		
Gasifier Efficiency		75%
Coal Cost ($/mmBtu)	$	1.25
Annual coal cost	$	44,846,820
Syngas Fuel Cost $/mmBtu		**1.67**
O&M		
Annual O&M	$	19,000,000
O&M ($/mmBtu)		**0.71**
Total Syngas Cost ($/mmBtu)		**4.03**
National Gasification Strategy		
Number of IGCC Plants		28
Cost of IGCC Plants		22,344,000,000
IGCC Loan Guarantee Program		17,875,200,000
IGCC Plants Syngas Production (mmBtu)		753,426,576
Number of Industrial Gasifiers		30
Cost of Industrial Gasifiers		14,250,000,000.0
Industrial Gasifier Loan Guarantee Program	$	11,400,000,000
Industrial Gasifier Syngas Production (mmBtu)		807,242,760
Total Investment under Program	$	36,594,000,000
Total Loan Guarantee Program	$	29,275,200,000
Program Total Syngas Production (mmBtu)		1,560,669,336
Natural Gas Equivalent (Mcf)		1,515,212,948

APPENDIX B: LEGISLATIVE CONCEPTS FOR NATIONAL GASIFICATION STRATEGY LOAN GUARANTEE PROGRAM

1. PURPOSE AND GOALS.

The purpose of this act is to establish a federal loan guarantee program as part of the National Gasification Strategy to stimulate commercial deployment of integrated gasification combined cycle and industrial gasification technology in order to:

a. Develop gasification as a gas supply option that provides the energy equivalent of 1.5 TCF of natural gas:

b. Promote the use of domestic coal and biomass and other domestic fuel resources;

c. Reconcile coal use and environmental protection;

d. Reduce the demand pressure on domestic natural gas prices and supply by promoting the use of gas derived from domestic coal and biomass and other domestic fuel resources for electric generation and industrial use;

e. Provide affordable and reliable electricity and gas supply;

f. Promote the position of the U.S. as a global leader in advanced gasification technology; and

g. Accomplish the goals in subsections (a) through (f) of this section while restricting the burden on the federal budget.

2. DEFINITIONS.

a. The term "carbon capture ready" shall mean, with regard to a project, having a design that is determined by the Secretary of Energy to be capable of accommodating the equipment likely to be necessary to capture the carbon dioxide that would otherwise to emitted in flue gas from the project.

b. The term "IGCC project" shall mean a project for which coal will account for at least 50% of annual heat input and any other liquid or solid fuel will account for the remainder, and electricity will account for at least 75% of annual useful energy output, during the term of the federal loan guarantee under section 3.

c. The term "industrial coal gasification project" shall mean a project for which coal, biomass, and any other liquid or solid fuel, in any combination, may account for annual fuel heat input, and electricity will account for less than 75% of annual useful energy output, during the term of the federal loan guarantee under section 3.

d. The term "project" shall include an IGCC project or an industrial coal gasification project and shall mean:

1. Any combination of equipment located at a specific site and used to gasify coal, biomass, or other liquid or solid fuel, and remove pollutants from the gas, for industrial purposes (except electric generation); or

2. Any combination of equipment used to gasify coal, biomass, or other liquid or solid fuel, burn the gas in a turbine, and generate electricity (including existing natural gas combined cycle plant refueled using gasification technology).

e. The term “Secretary of Energy” shall mean the Secretary of the United States Department of Energy.

f. The term “total plant investment” shall mean the total amount, for a project, of the engineering, procurement, and construction costs, the owner’s costs in developing and starting up the project, and the construction financing costs.

3. SCOPE AND DEADLINES.

a. The federal loan guarantee program will provide for a total amount of $30 billion of federal loan guarantees, with authorization of appropriations of $3 billion over 5 years for budget scoring under the Federal Credit Reform Act of 1990, such that:

1. Up to $12 billion of the total amount of federal loan guarantees will be issued for industrial coal gasification projects; and

2. The remaining portion of the total amount of federal loan guarantees will be for IGCC projects.

b. The federal loan guarantee program will be administered by the Secretary of Energy, who shall promulgate regulations implementing the program within 12 months of the date of enactment of this act and shall issue federal loan guarantees, and commitments for such federal loan guarantees, pursuant to such regulations. The Secretary of Energy may, to the extent he or she determines to be appropriate, require by regulation and collect application and other fees to cover administrative costs and insurance fees to reduce the burden on the federal budget.

c. The Secretary of Energy shall issue the federal loan guarantees under subsection (b) of this section for projects selected under section 6, and shall require construction to commence on such projects, within ten years after the deadline under subsection (b) of this section for promulgation of implementing regulations. In issuing such federal loan guarantees, the Secretary of Energy shall give priority first to projects that will commence operation by December 31, 2009 and then to projects that will commence construction by December 31, 2009.

4. PROVISIONS OF FEDERAL LOAN GUARANTEES.

Each federal loan guarantee under section 3 shall:

a. Cover up to 80% of the total plant investment in each project selected under section 6, provided that the project owner must provide equity investment in such project of at least 20% of the total plant investment;

b. Apply to the project’s long-term debt obligations, which may, at the discretion of the Secretary of Energy, be non-recourse and shall have a term of up to 30 years; and

c. Be backed by the full faith and credit of the United States.

5. QUALIFYING PROJECTS.

a. The Secretary of Energy shall establish, by regulation, the submission requirements and procedures for an application for a federal loan guarantee under section 3.

b. In order to be considered by the Secretary of Energy for a federal loan guarantee, the owner of a proposed project must demonstrate, in an federal loan guarantee application submitted to the Secretary of Energy, that:

1. For a proposed IGCC project, the project will meet the following requirements:

A. Coal will account for at least 50% of annual fuel heat input, and any other liquid or solid fuel will account for the remainder, during the term of the federal loan guarantee;

B. Electricity will account for at least 75% of annual useful energy output during the term of the federal loan guarantee;

C. To the extent that electricity will be generated at the project, the generation portion of the project will have a design heat rate of 8,900 btu/KWh (HHV) or lower. To the extent that the project gasifies coal, biomass, or other fuel, and removes pollutants from the gas, for industrial purposes (except electric generation), the non-generation portion of the project will have a design efficiency of [TO BE DETERMINED]; and

D. The project will be a new power plant, a repowering of an existing coal power plant, or a refueling of an existing natural gas combined cycle power plant; and

2. For a proposed industrial coal gasification project, the project will meet the following requirements:

A. Coal, biomass, or other liquid or solid fuel, in any combination, will account for annual fuel heat input during the term of the federal loan guarantee; and

B. To the extent that electricity will be generated at the project, the generation portion of the project will have a design heat rate of 8,900 Btu/KWh (HHV) or lower (except in the case of facilities using biomass). To the extent that the project gasifies coal, or other fuel, and removes pollutants from the gas, for industrial purposes (except electric generation), the non-generation portion of the project will have a design efficiency of [TO BE DETERMINED] (except in the case of facilities using biomass).

3. To the extent that electricity will be generated at the project, the project will comply with the following enforceable emission limitation requirements, in addition to any other applicable federal or state emission limitation requirements:

A. 99% removal (including any fuel pretreatment) of sulfur from the coal-derived gas, and any other fuel, burned in the generation of electricity and total sulfur dioxide emissions in flue gas from the electric generation portion of the project not exceeding 0.04 lb/mmBtu;

B. 95% removal (including any fuel pretreatment) of mercury from the coal-derived gas, and any other fuel, burned in the generation of electricity;

C. Total nitrogen oxides emissions in the flue gas from the electric generation portion of the project not exceeding 0.025 lb/mmBtu; and

D. Total particulate emissions in the flue gas from the electric generation portion of the project not exceeding 0.01 lb/mmBtu.

4. To the extent that the project gasifies coal, biomass, or other fuel, and removes pollutants from the gas, for industrial purposes (except electric generation), the project will comply with the following enforceable emission limitation requirements, in addition to any other applicable federal or state emission limitation requirements:

A. 99% removal (including any fuel pretreatment) of sulfur from the coal-derived gas, and any other fuel, used in the non-electric generation portion of the project and total sulfur dioxide emissions in the flue gas from the non-electric generation portion of the project not exceeding [TO BE DETERMINED];

B. [95% or TO BE DETERMINED] removal (including any fuel pretreatment) of mercury from the coal-derived gas, and any other fuel, used in the non-electric generation portion of the project;

C. Total nitrogen oxides emissions in the flue gas from the non-electric generation portion of the project not exceeding [TO BE DETERMINED]; and

D. Total particulate emissions in the flue gas from the non-electric generation portion of the project not exceeding [TO BE DETERMINED].

5. The project will be carbon capture ready (except for biomass projects which are assumed to be net zero carbon emissions).

6. The project will have an assured revenue stream (acceptable to the Secretary of Energy, consistent with the purpose and goals in section 1) covering the project capital and operating costs (including the costs of servicing all debt obligations covered by the federal loan guarantee) through:

A. Procedures established by the State public utility commission or commissions, or by the other governmental body or bodies, with jurisdiction over the prices charged for the electricity produced by the project and providing:

i. Upfront review, and ongoing periodic review (starting during construction), of the prudence of project capital and operating costs; and

ii. Timely recovery of those project capital and operating costs determined to be prudent; or

B. Insurance, customer guarantees, or other credit enhancements that provide credit and federal budget scoring acceptable to the Secretary, consistent with the purpose and goals in section 1.

<u>6. PROJECT SELECTION AND ISSUANCE OF FEDERAL LOAN GUARANTEES.</u>

a. The Secretary of Energy shall establish, by regulation, the review and approval criteria and procedures for selecting a proposed project for a federal loan guarantee under section 3.

b. The review and approval criteria applied to each proposed project shall include the following:

1. A determination that the project meets the application demonstration requirements in subsection (b) of section 5 and the budget scoring requirement in subsection (d) of this section;

2. A determination that the project is technically and economically feasible;

3. An evaluation of the financial strength of the project;

4. An evaluation of the environmental performance of the project;

5. The project priorities in subsection (c) of section 3; and

6. Any other criteria determined by the Secretary of Energy to be consistent with the purpose and goals in section 1.

c. In applying the review and approval criteria to each proposed project, the Secretary of Energy shall ensure that, to the extent practicable, the portfolio of projects issued federal loan guarantees under section 3 will result in gasification of a diversity of coal types and other fuel types and in a geographic diversity of projects.

d. The Secretary of Energy shall issue a federal loan guarantee to a proposed project only if the federal loan guarantee for such project has a budget scoring under the Federal Credit Reform Act of 1990 that does not exceed a percentage level established by the Secretary of Energy, consistent with the purpose and goals specified in section 1.

<u>7. ADDITIONAL REQUIREMENTS AND PROCEDURES.</u>

The Secretary of Energy is authorized to adopt by regulation:

a. Conditions for the disbursement of funds subject to a federal loan guarantee under section 3;

b. Procedures and requirements for monitoring and reporting the status of projects issued federal loan guarantees under section 3; and

c. Procedures for taking actions to restrict the impact on the federal budget in the event of foreclosure of a project issued a federal loan guarantee under section 3.

8. CARBON REDUCTION.

The Secretary of Energy is authorized to provide:

a. $1 billion in grants or other incentives to support research, development, and demonstration of technologies for the capture and storage of carbon from projects for which federal loan guarantees under section 3 are issued and for research, development, and demonstration of biomass gasification technologies; and

b. $2 billion in tax credits, grants, and loan guarantee scoring to support commercial deployment of technologies for capture and storage of carbon from projects for which federal loan guarantees under section 3 are issued.

NOTES

[1] Energy Information Administration, *Natural Gas Monthly*, Nov. 2004, Table 4.
[2] Based on $3.30/mmBtu applied to current national consumption of 22 TCF.
[3] The economic consequences of high prices are described broadly in the 2003 House Speaker's Task Force for Affordable Natural Gas report. See House Energy and Commerce, Task Force for Affordable Natural Gas, *Natural Gas: Our Current Situation,* (Sept. 30, 2003).
[4] This cost assumes low federal budget scoring of the loan guarantees based on a program requirement that the guarantees are secured with strong credit backing.
[5] See Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3a.htm
[6] See Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3M.htm; See also National Petroleum Council, Balancing Natural Gas Policy—Fueling Demands of a Growing Economy (Sept. 2003, National Petroleum Council, Washington DC), pg. 22.
[7] National Petroleum Council (Sept. 2003) pg. 5.
[8] See Energy Information Administration, *Annual Energy Outlook 2002*, Table 23, Comparison of Natural Gas Forecasts (showing that the range of projected natural gas wellhead prices in 2020 was between $2.94/Mcf to 3.65/Mcf).
[9] Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3m.htm indicating October 2004 wellhead prices were $5.45/Mcf, which equates to $5.3/mmBtu.
[10] See Energy Information Administration, *Short-term Energy Outlook*, December, 2004.
[11] Annual Energy Outlook Reference Case forecasts between 1996 and 2002 projected U.S. dry gas production in 2005 would be between 19.7 and 22.7 TCF, with the average across the projections being 21.3 TCF. The December 2004 Short-Term Energy Outlook now projects 19.1 TCF of production, which is 2.2 TCF below the average of the projections during the seven year period prior to 2002.
[12] Energy Information Administration, *Annual Energy Outlook 2005*, Table A3.
[13] Id. Table A13, A14.
[14] American Chemistry Council, "Energy Costs Destroying Chemical Manufacturing Competitiveness," (Nov. 3, 2004 news release).
[15] The Fertilizer Institute, "Fertilizer Industry Weights in on Energy Crisis at Natural Gas Summit, (June 26, 2003 news release).
[16] Id.
[17] For example, on May 4, 2004, Duke Energy announced the sale of 5,325 MW of eight natural gas-fired power plants in the Southeast U.S. for $475 million, or about $90/MW, which is less than one-fifth of their original cost. In a related matter, Duke Energy announced in January, 2004 that it was taking a $3 billion write off from 2003 earnings, in large part because of the decline in value of its natural gas generation fleet in the Southeast U.S. See http://www.dukeenergy.com/news/releases/2004/jan/2004010701.asp. As of April 2004 as much as 33,000 MW of distressed natural gas capacity was for sale, and many natural gas-fired power plants had already been repossessed by lending institutions, including Citibank (4,150 MW), Societe Generale (5,550 MW) and BnP Paribas (3,400 MW). See NETL, "Potential for NGCC Plant Conversion to a Coal-Based IGCC Plant - - A Preliminary Study," May 2004.
[18] In the regulated Florida market, for example, combined cycle power plants operated at 50% capacity factors in 2003 despite high natural gas prices. See Florida Public Service Commission, *Statistics of the Florida Electric Utility Industry 2003*, Sept. 2004.
[19] See Energy Information Administration, *Annual Energy Outlook 2005*, Table A14.
[20] Based on 2003 data. See Energy Information Administration, Office of Oil and Gas, Reserves and Production Division at:
http://www.eia.doe.gov/pub/oil_gas/natural_gas/analysis_publications/ngcap2003/ngcap2003.html
[21] For example, the Annual Energy Outlook 2005 production forecast indicates lower 48 production will peak around 2015. See Energy Information Administration, *Annual Energy Outlook 2005*, Table A14.
[22] See National Commission on Energy Policy (NCEP), *Ending the Energy Stalemate, A Bipartisan Strategy to Meet America's Energy Challenges* (Washington DC, National Commission on Energy Policy, Dec. 2004) Figure 4-4.
[23] Dow Jones Newswire, "Alaska Gas Pipeline Project Aided by Gov't Help," Oct. 27, 2004.

[24] NCEP (Dec. 2004) pg. 46; citing National Commission on Energy Policy, Increasing U.S. Natural Gas Supplies: A Discussion Paper and Recommendations (Washington, DC National Commission on Energy Policy, 2003).
[25] See H.R.4837, *Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act*, 2005.
[26] See H.R. 4520, American Jobs Creation Act of 2004, Sec. 706-707.
[27] Energy Information Administration, *Annual Energy Outlook 2005*, Table A13.
[28] The terminals are located in Cove Point, Maryland; Elba Island, Georgia, Everett, Massachusetts, and Lake Charles, Louisiana.
[29] Energy Information Administration, *U.S. LNG Markets and Uses*, June 2004.
[30] Id.
[31] For example, ExxonMobil announced in December 2004 they had arranged $12 billion of financing to move forward with their joint venture Qatargas II project (See Dallas Business Journal, December 15, 2004) and Shell announced in March 2004 an agreement with Libya to develop LNG resources (See BBC News, March 25, 2004).
[32] Energy Information Administration at: http://tonto.eia.doe.gov/dnav/ng/hist/n3045us2a.htm; Energy Information Administration, *Short-term Energy Outlook*, December 2004.
[33] In the last 5 years, 115,000 MW of NGCC power plant capacity was built that was designed to operate about 65 percent of the time. On average, these plants are now reportedly running less than 15 percent of the time. At an average of 15 percent capacity factor, the NGCC plants use about 1 TCF/year of natural gas, if they operated at the expected 65% capacity factor they would use 4.3 TCF/year, resulting in a 64 percent increase in electric generator natural gas demand without additional capital investment.
[34] Syngas also contains some carbon dioxide (CO_2), moisture (H_2O), hydrogen sulfide (H_2S) and carbonyl sulfide (COS) as well as small amounts of methane (CH_4), ammonia (NH_3), hydrogen chloride (HCI) and various trace components from the feedstock. See SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 7.
[35] The heat content of syngas can vary depending on the gasifier type and fuel feedstock. Typical heat content of syngas produced from large gasification systems is around 250 Btu/cf, which is 24 percent of the 1,028 Btu/cf heating value of dry natural gas.
[36] Methanation is a process for removing carbon monoxide from gas streams or for producing methane by the reaction CO + 3H2 $\rightarrow$ CH4 + H2O.
[37] Presentation by James Childress, "2004 World Gasification Survey: A Preliminary Evaluation," Gasification Technologies Conference, Washington, DC (Oct. 4-6, 2004).
[38] In addition to the two integrated gasification combined cycle (IGCC) facilities operating in the U.S., American Electric Power and Cinergy Corporation have both announced intentions to develop new IGCC power plants in the U.S. and Excelsior Energy and Southern Company received funding grants in 2004 from the Department of Energy to develop IGCC facilities.
[39] GE Energy Gasification Technologies acquired the ChevronTexaco process July 1, 2004.
[40] ConocoPhillips acquired the patents and intellectual property rights to Global Energy's proprietary E-GAS gasification process in 2003. This technology was originally developed by Dow Chemical Company and later transferred to Destec, a partially held subsidiary of Dow Chemical. In 1997, Destec was purchased by Houston-based NGC Corporation, which became Dynegy, Inc. in 1998. In December 1999, Global Energy Inc. purchased the gasification technology from Dynegy and in 2003 ConocoPhillips purchased the technology from Global Energy (see DOE, Clean Coal Technology Topical Report Number 20, "The Wabash River Repowering Project—an Update," Sept. 2000, p. 4).
[41] The performance and economics of the Shell gasification system are described in a paper presented by Shell at the 2004 Gasification Technology Conference in Washington DC. See H.V. van der Ploeg, T. Chhoa, P.L. Zuideveld, *The Shell Coal Gasification Process for the US Industry* (Oct. 2004).
[42] See NETL, *Major Environmental Aspects of Gasification-Based Power Generation Technology*, Dec. 2002, citing DOE—EPRI Report 1000316, Dec. 2000. See also Jeremy David and Howard Herzog, "The Cost of Carbon Capture," 2000.
[43] NCEP (2004).
[44] See NETL, *Major Environmental Aspects*, Dec. 2002, citing DOE—EPRI Report 1000316, Dec. 2000. See also Jeremy David and Howard Herzog, *The Cost of Carbon Capture*, 2000.

[45] Larson, E. D., S. Consonni, and R. Katofsky, "A Cost-Benefit Assessment of Biomass Gasification Power Generation in the Pulp and Paper Industry," Final Report, 8 October 2003 (available at: http://www.princeton.edu/~energy/publications/texts.html#2003).
[46] NCEP (2004), p. 55.
[47] Id.
[48] Rosenberg, William G., Dwight C. Alpern, Michael R. Walker, *Deploying IGCC Technology in this Decade with 3Party Covenant Financing*, Kennedy School of Government, Harvard University, May 2005 Revision (available at: www.ksg.harvard.edu/bcsia/enrp).
[49] Id. Vol. I, pg. 14.
[50] Id. Vol. I, Table 5-7, Table 5-8.
[51] The devaluation and market availability of underutilized natural gas generation assets presents an important opportunity for early and cost-effective coal gasification refueling. The combined cycle power block associated with new NGCC power plants can be converted to use synthesis gas from a coal gasifier for a nominal cost that could be more than made up for by the savings associated with using a distressed, devalued NGCC asset.
[52] The legislation states: "The Secretary shall not require as a condition of issuing a Federal guarantee instrument under this section any contractual commitment or other form of credit support of the sponsors (other than equity contribution commitments and completion guarantees), or any throughput or other guarantee from prospective shippers greater than such guarantees as shall be required by the project owners." See H.R.4837, Military Construction Appropriations and Emergency Hurricane Supplemental Appropriations Act, 2005, Sec. 116(b)(3).

Attachment 3

Article in Forbes Magazine

Forbes, November 1, 2004: **The Other Gas Crunch: How coal can help reduce soaring natural gas prices--and satisfy environmentalists**
http://www.forbes.com/forbes/2004/1101/044_print.html

By William G. Rosenberg

Prices at the pump have gotten a lot of attention lately, but it's time to focus on another gas price crunch.

The price of natural gas has more than doubled in the last four years. This presents a prime opportunity to make widespread use of a long-overlooked technology: producing gas from coal.

The U.S. is the Saudi Arabia of coal: While we have only 3% of the world's natural gas reserves, we have a quarter of the world's coal. In the late 1980s, however, investments in coal fell as cheaper and cleaner gas plant technology came on line; over the last ten years power companies have invested $100 billion in natural-gas-powered plants but very little in coal-powered ones. The expectation was that gas would remain inexpensive and U.S. and Canadian supplies would meet demand. But today gas that was supposed to cost $2.50 per million Btu costs $5 or more. Higher prices have caused chemical and fertilizer companies to cut back production and lay off workers. And home-heating costs will rise this winter.

The natural gas price squeeze gives us the opportunity to usher in the return of coal power--not power from conventional high-polluting plants but from a new generation of much cleaner technology. Processes that first gasify coal--adding steam and oxygen under pressure to produce hydrogen, carbon monoxide and other gases, turning it into fuel that can be burned like natural gas--remove more than 90% of toxic mercury emissions as well as impurities such as sulfur, nitrogen and particulates.

Moreover, technology makes it possible to separate out carbon dioxide, the chief culprit in global warming, before it's released into the atmosphere. Instead, the separated CO_2 could be piped underground. This process has yet to be developed for use commercially, but the science is promising.

Manufacturers like Eastman Chemical have used technologies like these for 21 years, and the Department of Energy has successfully demonstrated coal-gasification electricity plants in Indiana and Florida. Gasified coal, though, is not without financial obstacles. It costs 20% more to build coal-gasification plants than traditional coal plants. That means the electric customer is going to pay a bit more. There are still operating uncertainties associated with the early adoption of the technology on a commercial scale.

In a report released by Harvard's John F. Kennedy School of Government, my colleagues Dwight Alpern and Michael Walker and I spell out how the new coal technology might be made commercially viable if utilities, state public utility commissions and the Department of Energy join together to finance an initial fleet of plants. Federal loan guarantees will allow higher leverage and lower interest rates, thereby reducing cost of capital by 38%. These savings would be passed on to industrial and residential customers in return for state public utility commissions guaranteeing revenue streams to recover costs. Coal-gasification power plants financed and regulated under this covenant would yield lower-price power than either new conventional coal or natural gas plants. Once half a dozen plants are built and operating, future construction and operating costs should decline.

Interest is already building. Recently American Electric Power, the nation's largest electric utility, committed to invest in a large coal-gasification plant, pending financing and regulations. At this point the waste carbon dioxide would be released into the atmosphere. Cinergy has made a similar announcement; in June GE purchased the gasification business developed by ChevronTexaco, joining RoyalDutch/Shell and ConocoPhillips as active technology vendors; other companies are looking to revive idled natural gas power plants by refueling them with cheaper gasified coal. Environmentalists are cautiously optimistic that clean coal technologies deployed here can be used in China and India, which will inevitably be burning their enormous coal reserves to fuel industrial expansion.

Coal gasification will not eliminate our need for additional natural gas, but it could help reduce our energy costs and preserve American jobs. Clean coal is the solution hidden inside the crisis of natural gas prices, if only we seize it.

William G. Rosenberg is a Senior Fellow at the Kennedy School of Government, Harvard University. His career has included 14 years as corporate lawyer and energy and environmental consultant, 11 years as real estate developer and venture capitalist, and 13 years of public service. In the public sector, he served as Chairman, Michigan Public Service Commission; Assistant Administrator, Federal Energy Administration for Energy Resource Development; and Assistant Administrator, Environmental Protection Agency for Air and Radiation.

Attachment 4

April 21, 2005 Senate Energy Committee Testimony

HARVARD UNIVERSITY
JOHN F. KENNEDY SCHOOL OF GOVERNMENT

William G. Rosenberg
Senior Fellow

Belfer Center for Science & International Affairs
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TESTIMONY

Senate Energy & Natural Resources Committee
William G. Rosenberg
April 21, 2005

Chairman Domenici, Senator Bingaman, Members of the Committee: Thank you for this opportunity to appear today.

My name is William G. Rosenberg and I am a Senior Fellow at the Belfer Center for Science and International Affairs at Harvard's Kennedy School of Government.

The country stands at the brink of a decision on whether a proven technology can be expanded to unleash the potential that our vast coal resources become a clean source of energy and, at the same time, help reduce the upward spiral of energy costs that consumers and industry are experiencing today. High natural gas prices are causing tens of thousands of layoffs and production cutbacks across the country.

If Congress jumpstarts investment in gasification to produce new supplies of "syngas" for electricity generation and industrial gas, natural gas demand and prices would fall, LNG imports would moderate, new coal power plants would be less polluting and technology would be commercially established that facilitates CO_2 capture and storage. Widespread gasification of coal and biomass is one of the few near-term actions that can make a difference.

Senators Alexander and Johnson recently introduced natural gas bills with gasification incentives that could meet those objectives.

Over the past 2 years, my colleagues and I at the Kennedy School have developed a proposal to jumpstart financing and construction of a fleet of gasification projects. The proposal focuses on a federal loan guarantee incentive approach, because loan guarantees minimize federal budget costs.

Our proposal works like this:

- 80% Loan guarantees would make capital available to finance IGCC and Industrial Gasification projects that meet economic and environmental performance standards and deploy commercially available technology.
- Cost of capital would be reduced by almost 40% for IGCC projects, which would offset the impact of higher construction costs and make IGCC power cost competitive with power from new PC plants.

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- For electric projects, State Public Utility Commissions would assure that sufficient revenues are collected to pay debt service and minimize federal risk of default.
- For industrial gasification, purchase contracts would be signed for industrial by credit worthy companies..
- These credit enhancements would prevent the type of losses incurred by the Synfuels Corporation and would limit budget "scoring" to 10% of the loan.

The accompanying chart compares budget costs for a $1 billion IGCC plant under the loan guarantee program with grant or investment tax credit incentives.

The chart compares federal budget costs for a $1 billion IGCC plant:

- Blue—loan guarantees cost $80 million
- Orange—20% grants and investment tax credits cost $200 million
- Red—50% direct subsidies cost $500 million

Bottom line, direct grants and tax credits would be 2 1/2-5 times more expensive than loan guarantees.

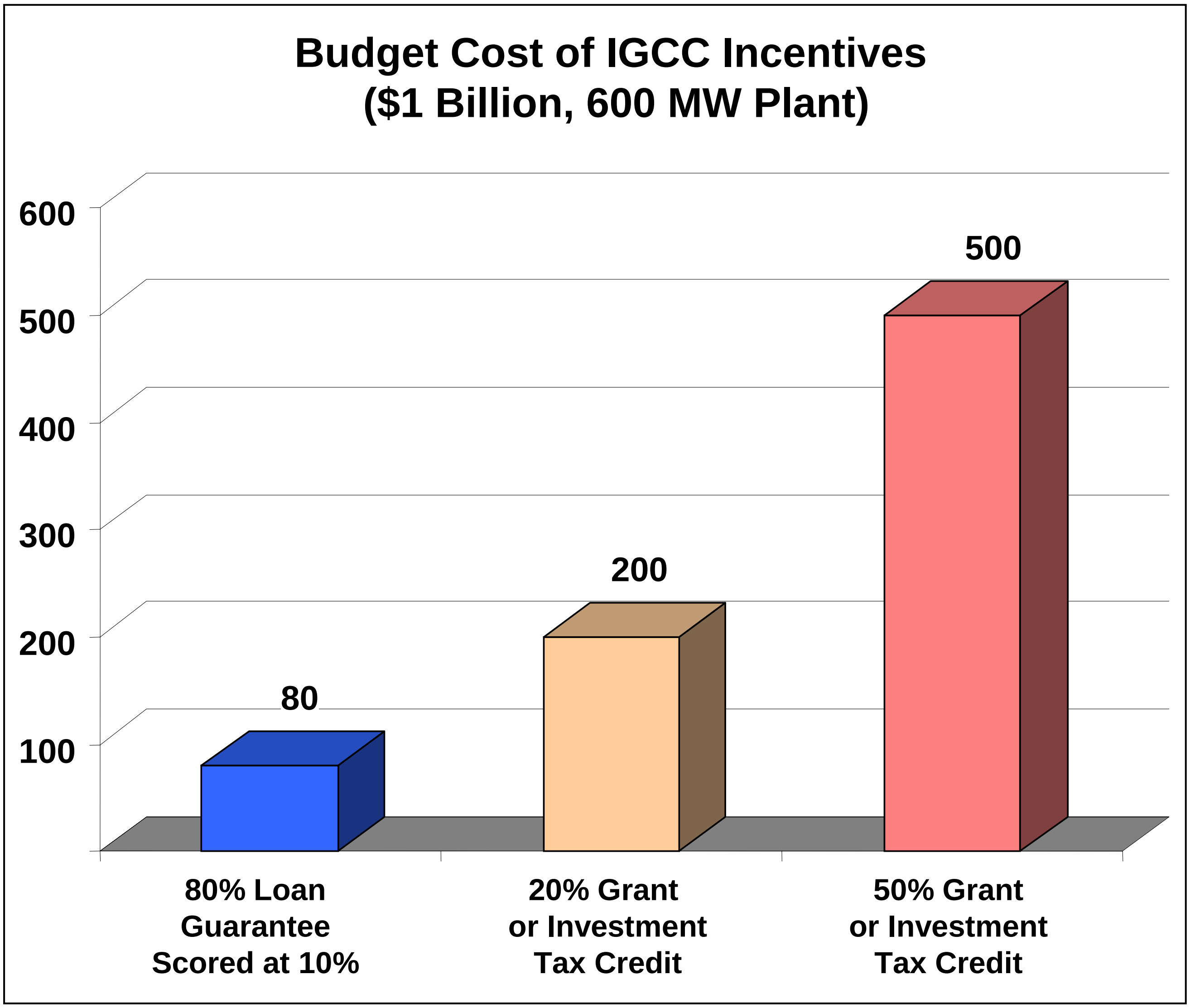
Flexibility for direct incentives would be appropriate where loan guarantees are not feasible, like public and coop utilities.

The loan guarantee program would provide adequate incentive to construct a robust fleet of gasification projects, while allowing this Committee to remain within practical budget constraints. For $1 billion of scoring authorization, 20 projects, divided between electricity and industrial gasification, could produce syngas with the energy equivalent of 500 bcf of natural gas. $3 billion would yield the energy equivalent of the Alaskan Gas Pipeline.

Federal loan guarantees could make gasification technology broadly available across the country, delivering affordable syngas at $4.50/mmBtu in today's $7 natural gas market.

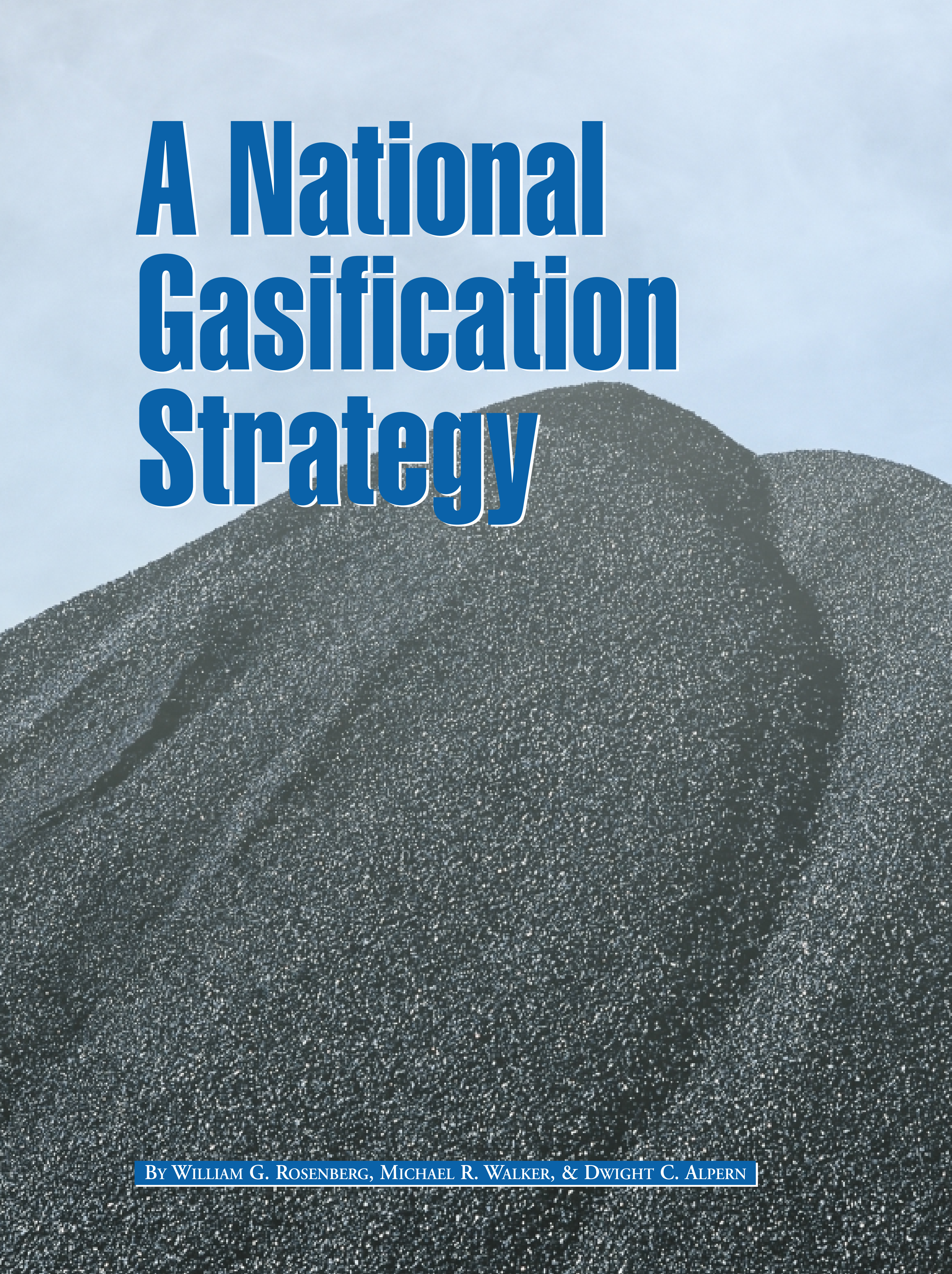
Thank you.

More detailed descriptions of the ideas presented in this testimony are provided in: Rosenberg, William G., Dwight C. Alpern, Michael R. Walker, *Deploying IGCC Technology in this Decade with 3Party Covenant Financing*, Kennedy School of Government, Harvard University, July 2004; and Rosenberg, William G., Dwight C. Alpern, Michael R. Walker, *National Gasification Strategy: Gasification of Coal & Biomass as a Domestic Gas Supply Option*, Kennedy School of Government, Harvard University, January 2005. Both papers are available at: www.ksg.harvard.edu/bcsia/enrp.


Budget Cost of IGCC Incentives
($1 Billion, 600 MW Plant)
600
500
400
300
200
100
80
200
500
80% Loan
Guarantee
Scored at 10%
20% Grant
or Investment
Tax Credit
50% Grant
or Investment
Tax Credit

Attachment 5

Article in Public Utility Fortnightly



A National Gasification Strategy

By William G. Rosenberg, Michael R. Walker, & Dwight C. Alpern

Presenting a program to stimulate robust coal-gasification technology deployment at low federal cost.

Near-term deployment of gasification technologies can supplement natural-gas supply, reduce demand, and promote long-term U.S. energy security and affordability. But near-term deployment must overcome high capital costs that affect commercial competitiveness and capital availability.

A national gasification strategy that provides federal loan guarantees and other incentives for industrial and electricity sector investments in gasification technology can overcome these hurdles and stimulate a robust deployment. By relying on federal loan guarantees as the primary initial incentive approach, federal budget costs can be minimized while jump-starting construction of significant capacity.

An important policy choice faces the U.S. Congress as it considers where gasification fits into U.S. energy policy. Would the national interest be best served by facilitating a limited number of prototype gasification facilities, or by boldly helping investors finance a substantial fleet of gasification projects to counter the natural gas shortfall and substitute for higher polluting direct coal-combustion facilities?

We propose a robust program leading to 50 commercial, industrial, and integrated gasification combined-cycle (IGCC) power plants that will deploy a variety of gasification technologies using coal, biomass, and petroleum-waste fuels. These plants also will help relieve high natural-gas demand and prices, support a move toward greater energy independence (and away from overreliance on imports of liquefied natural gas), and create multiple commercial platforms for demonstrating carbon capture, sequestration, and hydrogen-fueled technologies.[1]

Deployment Challenge

Despite substantial environmental benefits and a growing commercial interest in gasification technologies, commercial IGCC power plants and industrial gasification facilities have not yet materialized in the United States because of concerns over financing, cost, and financial risk. Most estimates suggest that the capital costs associated with the first generation of commercial IGCC power plants will be about 20 percent higher than the cost of a new pulverized coal plant, with IGCC operating and construction costs less certain. A recent filing by American Electric Power, which is seeking to build an IGCC power plant if the right regulatory treatment and incentives are available, indicated capital costs could be as high as $2,000/kW, well above most previous estimates for pulverized coal (PC) or IGCC. Unlike PC power plants, IGCC technology is not perceived to have sufficient commercial experience for developers to be comfortable with its operating performance, which has been demonstrated only at a handful of facilities.

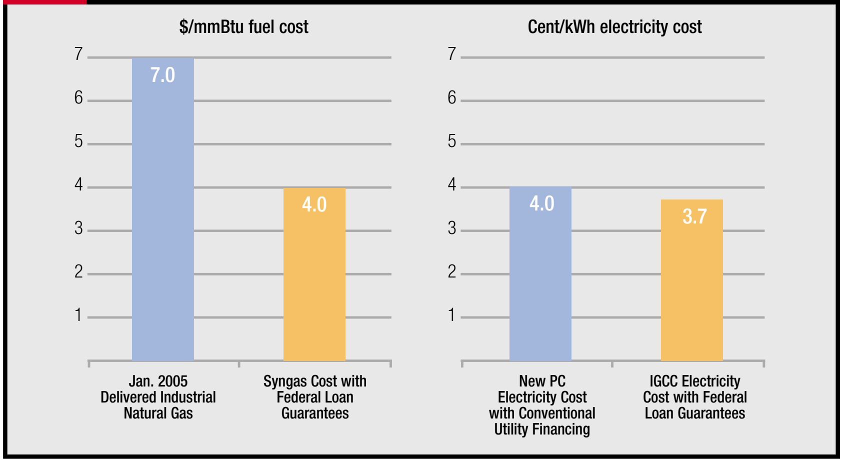
A 2003 decision by the Wisconsin Public Service Commission approving a WEPCO proposal to build two PC power plants, but rejecting the company's proposed IGCC facility, illustrates the chicken and egg problem facing IGCC technology. In Wisconsin, the commission determined that "IGCC technology, while promising, is still expensive and requires more maturation. For these reasons, the application to construct the IGCC unit is denied."[2] For IGCC technology to become commercially mature and economic it must be deployed, but to be deployed it needs to be perceived as mature and economic. The National Gasification Strategy described below is designed to overcome this dilemma.

Federal Incentives

Our National Gasification Strategy to stimulate investment in commercially available technology could improve natural gas affordability and security, help domestic industry, and reconcile coal use and environmental protection. A 5- to 10-year federal incentive program designed to stimulate commercial investments in 50 gasification plants across the country could provide the energy equivalent of the 1.5 Tcf of natural gas—equal to the projected Alaskan Gas Pipeline delivery—and deploy a technology capable of addressing the environmental concerns associated with expanded coal use, including climate change. Adding domestic supplies equivalent to 1.5 Tcf could reduce the projected need for LNG imports by 35 percent in 2015.

The federal government has a number of policy levers that could be incorporated into a National Gasification Strategy to stimulate investment in gasification technologies, including credit financing support (*i.e.*, loans, loan guarantees, performance guarantees, or lines of credit), tax incentives (*i.e.*, investment tax credits, production tax credits, or accelerated depreciation treatment), or direct grants. In April, 2005, Sen. Lamar Alexander, R-Tenn., introduced legislation that calls for a national strategy to deploy gasification technologies in the face

Fig. 1 Cost of Syngas and IGCC Electricity with 80% Federal Loan Guarantees



of surging natural gas prices. Alexander's bill authorizes DOE to make direct grants to six IGCC projects, providing a 40 percent federal cost share for the first three plants and a 30 percent federal cost share for the next three, plus up to 20 percent investment tax credits for all of the plants.[3] The bill also provides $2 billion of authorization for industrial gasification incentives, which could be in the form of direct loans, loan guarantees, price supports, or federal purchase agreements, plus up to 20 percent investment tax credits. For electric generators, 50 to 60 percent of total incentives would amount to $400 million to $600 million per project.

Benefit of Loan-Guarantee Incentives

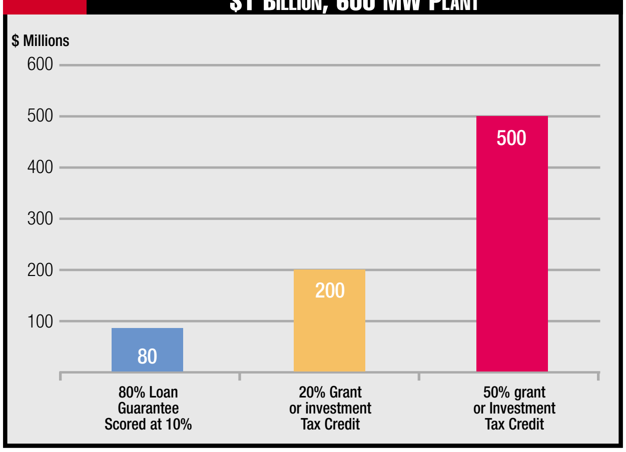
Loan guarantees provide a particularly attractive policy option for stimulating robust gasification deployment as part of a National Gasification Strategy, because they serve to provide access to capital markets, improve project economics, and, most important, minimize federal budget impacts. Reports by Rosenberg, *et al.*[4] describes how IGCC plants could be made commercially viable if utilities, state public utility commissions, and the federal government join together (an arrangement referred to as the "3Party Covenant") to finance a fleet of plants. Federal loan guarantees allow higher leverage and provide for lower cost debt, thereby reducing the cost of capital by 30 percent and the cost of energy by 17 percent.[5] These savings are sufficient to incorporate redundant components, while still enabling IGCC plants to produce energy at prices competitive with conventionally financed PC and for industrial gasifiers to produce syngas on site at prices well below delivered natural gas prices (*see Figure 1*).

The federal budget impact of different federal incentive approaches is a vital consideration given the current deficit and the focus in Washington on less government spending. Loan guarantees can minimize the federal budget cost of providing federal incentives, thereby enabling a given level of federal spending to achieve more gasification deployment and energy policy benefit.

The budget cost of federal loan guarantees is governed by the Federal Credit Reform Act of 1990 (FCRA), which makes commitments of federal loan guarantees contingent upon prior budget appropriations (budget scoring) of enough agency appropriations to cover the estimated present value cost of the guarantees. The present-value cost is estimated based on the dollar amount guaranteed and the risk of loan default, which typically is evaluated by rating agencies and the Office of Management and Budget. Without high creditworthiness to protect the guarantee, the scoring cost will be based strictly on project risks, making the program more risky and expensive for the federal government. The alternative is to secure strong credit enhancements to substantially mitigate default risks and protect the federal guarantee, which reduces the federal budget scoring and program cost.

A powerful way to mitigate loan-default risk is to establish an assured revenue stream to service debt obligations. In the electric power sector, this type of revenue stream can be created through a state public utility commission or other ratemaking body (*e.g.*, a municipality or rural electric cooperative) providing up-front and ongoing determinations of prudence of project costs and approvals of timely pass-through of project (or power purchase agreement) costs to ratepayers. This is the mechanism incorporated into the 3Party Covenant to provide revenue certainty to reduce the risk and budget scoring cost of

Fig. 2 Budget Cost of IGCC incentives for a $1 Billion, 600 MW Plant



the federal loan guarantee program. Similar risk-sharing arrangements are being proposed by major utilities considering IGCC projects when they require "full cost recovery," which assures debt and equity authorized returns will be covered in all events. Comparable credit (and budget scoring) could be created for industrial gasification projects through long-term off-take agreements (agreements to purchase syngas or electricity) with creditworthy purchasers, insurance arrangements, or other credit enhancements. The key factor is ensuring that the federal risk is mitigated sufficiently to reduce the budget scoring to an acceptable level, recommended as 10 percent or less of the loan principal. At this level, a loan guarantee program will be significantly less costly for the federal government than alternative policy options, such as tax credits or direct federal grants (*see Figure 2, p. 68*).

The decision to focus on a loan-guarantee program is largely a decision as to whether to promote a robust near-term deployment program, or a limited program for a few prototype projects. The primary advantage of loan guarantees is that they cost the federal government significantly less than grants or tax incentives to achieve the same level of project support. The savings are critical if Congress wants to pursue a national gasification program designed to help address natural gas supply and price concerns and improve energy independence and security.

A more affordable and secure energy future *(Cont. on p. 71)*

Gasification Technology

Gasification is the partial oxidation of a solid or liquid fuel feedstock to manufacture a gaseous product (synthesis gas or "syngas") made up of predominantly hydrogen (H_2) and carbon monoxide (CO).[1] Impurities, such as particulates, sulfur, nitrogen, and volatile mercury are cost-effectively removed from the syngas prior to combustion, using commercially proven systems to produce syngas that is almost as clean as natural gas. Synthesis gas has a lower heating value than natural gas,[2] but can be substituted readily in many industrial processes and in the generation of electricity with modern gas turbines. Synthesis gas also can be converted to synthetic natural gas (methane) using commercially available methanation catalysts.[3] By producing gas on site, gasification eliminates the need for additional pipeline capacity for fuel delivery.

According to a recent survey by the Gasification Technologies Council (GTC), there are 385 gasifiers in operation at 117 projects worldwide.[4] These gasifiers are used to produce liquid fuels in South Africa (Sasol facility); chemicals in the United States (Kingsport facility); electricity in the United States, Europe, and Japan (Polk, Wabash River, Puertollano, Buggenum, and Negishi facilities);[5] methane in the United States (Great Plains facility); and ammonia fertilizer in China and India. There are several different commercial gasifier designs available, including systems from GE Energy,[6] Conoco Phillips,[7] Shell,[8] Lurgi, and Noell. Each of these systems has been proven in commercial use around the world.

Gasification can be used to produce feedstocks, heat, steam, and electricity for a variety of industrial processes that currently use natural gas. For example, Eastman Chemical successfully has operated a GE Energy gasifier at its Kingsport, Tenn., facility since 1983 as the only source of gas for its chemical processes to produce film and other acetyl-based products. Similarly, Sasol operates one of the oldest and largest gasification operations in the world in South Africa, where high-ash coal is gasified with Lurgi gasifiers to produce a variety of liquid fuels and chemical products. Several players in the chemical industry are looking at new production technology to utilize syngas for the production of large-volume commodity chemicals based on natural gas liquids. In addition, China is constructing nine gasification systems for ammonia fertilizer production based on the Shell technology.—***WGR, MRW, and DCA***

Endnotes

1. Syngas also contains some carbon dioxide (CO_2), moisture (H_2O), hydrogen sulfide (H_2S), and carbonyl sulfide (COS) as well as small amounts of methane (CH_4), ammonia (NH_3), hydrogen chloride (HCl), and various trace components from the feedstock. See SFA Pacific, Inc., "Evaluation of IGCC to Supplement BACT Analysis of Planned Prairie State Generating Station," May 11, 2003, p. 7.
2. The heat content of syngas can vary depending on the gasifier type and fuel feedstock. Typical heat content of syngas produced from large gasification systems is around 250 Btu/cf, which is 24 percent of the 1,028 Btu/cf heating value of dry natural gas.
3. Methanation is a process for removing carbon monoxide from gas streams or for producing methane by the reaction $CO + 3H_2 \rightarrow CH_4 + H_2O$.
4. Presentation by James Childress, "2004 World Gasification Survey: A Preliminary Evaluation," Gasification Technologies Conference, Washington, D.C., Oct. 4-6, 2004.
5. In addition to the two integrated gasification combined cycle facilities operating in the United States, American Electric Power and Cinergy Corp. both have announced intentions to develop new IGCC power plants in the United States, and Excelsior Energy and Southern Co. received funding grants in 2004 from the Department of Energy to develop IGCC facilities.
6. GE Energy Gasification Technologies acquired the ChevronTexaco process on July 1, 2004.
7. ConocoPhillips acquired the patents and intellectual property rights to Global Energy's proprietary E-GAS gasification process in 2003. This technology was originally developed by Dow Chemical Co. and later transferred to Destec, a partially held subsidiary of Dow Chemical. In 1997, Destec was purchased by Houston-based NGC Corp., which became Dynegy Inc. in 1998. In December 1999, Global Energy Inc. purchased the gasification technology from Dynegy, and in 2003 ConocoPhillips purchased the technology from Global Energy (see DOE, Clean Coal Technology Topical Report Number 20, "The Wabash River Repowering Project—an Update," Sept. 2000, p. 4).
8. The performance and economics of the Shell gasification system are described in a paper presented by Shell at the 2004 Gasification Technology Conference in Washington, D.C. See H.V. van der Ploeg, T. Chhoa, P.L. Zuideveld, *The Shell Coal Gasification Process for the U.S. Industry*, Oct. 2004.

Coal: America's Great Resource

For two decades (1980-1999), annual average wellhead natural gas prices in the United States remained between \$1.5/MMBtu to \$2.6/MMBtu.[1] However, natural gas prices spiked in late 2000 above \$9/MMBtu and began a steady climb again in 2002 that has resulted in average delivered prices in the \$6-\$7/MMBtu range (*see Figure 1*).[2]

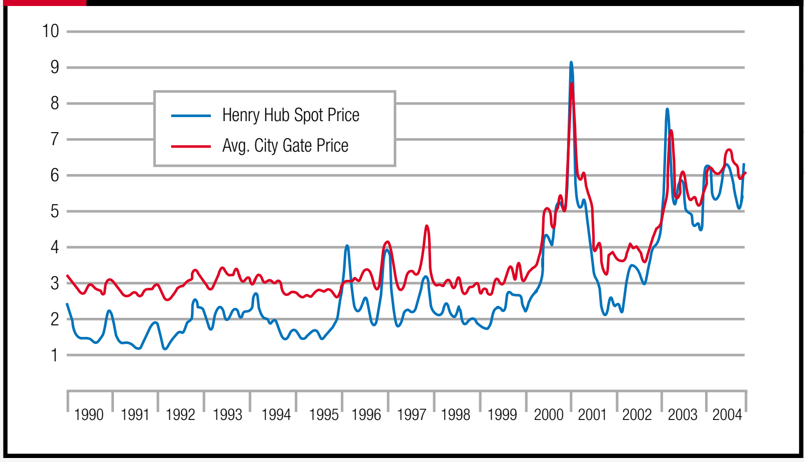
Over the next 20 years, U.S. natural gas demand is expected to grow by almost 40 percent, but production from on- and off-shore wells in the lower 48 states is expected to increase only 5 percent. Net imports from Canada and Mexico are expected to decline slightly as those countries consume more for their own use.[3] Consequently, the average delivered price of natural gas is predicted to remain above \$5.50/MMBtu through 2025, and 96 percent of the incremental supply needed to meet growing U.S. demand is forecast to come from overseas LNG imports (72 percent) and Alaska (24 percent) (*see Figure 2*). The continuation of historically high natural gas prices and the potential for U.S. dependence on overseas imports for needed supply also are cause for concern.

The pressure to increase natural gas supplies is being driven largely by growth in demand for natural gas from the electric power sector. More than 200,000 MW of new natural-gas generating capacity came on line between 1990 and 2004 (85 percent of all new capacity), and 180,000 MW came on line between 2000 and 2004 (96 percent of all new capacity)[4] (*see Figure 3*). Natural-gas demand in the electric power sector is projected to far outpace demand growth in other sectors, becoming the largest natural gas consuming sector by 2015 (*see Figure 4*).

Price trends driven by the combination of production constraints and demand growth are adversely affecting investors and consumers looking to natural gas as the clean, affordable answer to U.S. energy needs. Skyrocketing prices have undermined the economic viability of natural-gas generating stations built in competitive markets, hurt consumers dependent on natural gas to heat their homes, and are adversely affecting the U.S. economy and economic competitiveness.[5] The chemical industry, which is the largest industrial consumer of natural gas in the United States, estimates it has lost \$50 billion in business to foreign competition and more than 90,000 jobs since 2000 due to high natural gas prices.[6] Similarly, the fertilizer industry, where 70 to 90 percent of the cost of producing ammonia for fertilizer is the cost of natural gas, reported in 2003 that 11 ammonia plants representing 21 percent of U.S. capacity already had been closed, that only 50 percent of the remaining U.S. capacity was operating, and that two major U.S. fertilizer producers had already filed for bankruptcy.[7]

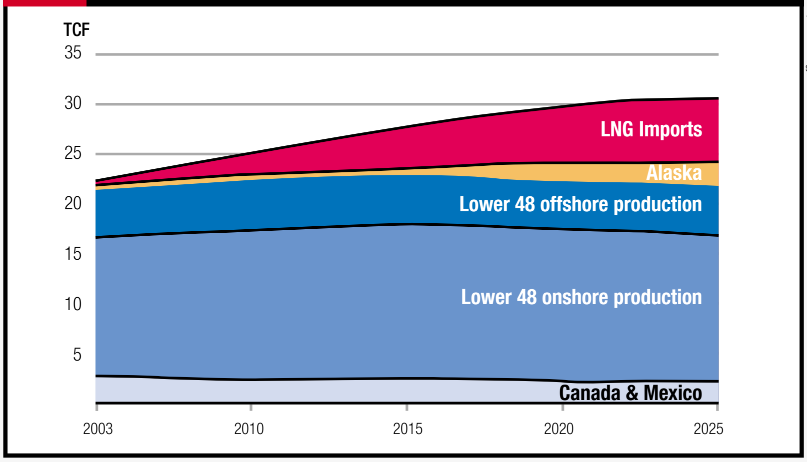
In contrast to natural gas, delivered coal prices have declined over the past decade, increasing the spread between coal and natural gas prices to more than \$4.00/MMBtu and sparking a renewed interest in coal power-plant development. According to the Department of Energy (DOE), as of September 2004, 100 new coal plants had been proposed in the United States, representing 63,000 MW of new coal capacity and \$73 billion of potential investment.[8] Although the United States holds less than 2 and 3 percent of world oil and natural gas reserves, it has more coal than any other country in the

Fig. 1 — Natural Gas Price Trends (1990-2004)



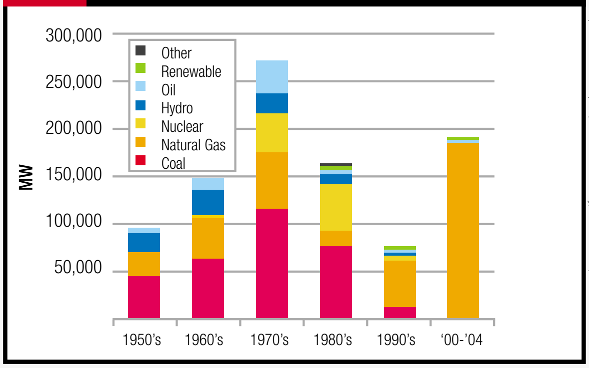
Sources: Henry Hub Spot Price: Reuters, *Wall Street Journal* and *Oil & Gas Journal*; City Gate Price: EIA at: *http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3m.htm*

Fig. 2 — Projected U.S. Natural Gas Supply



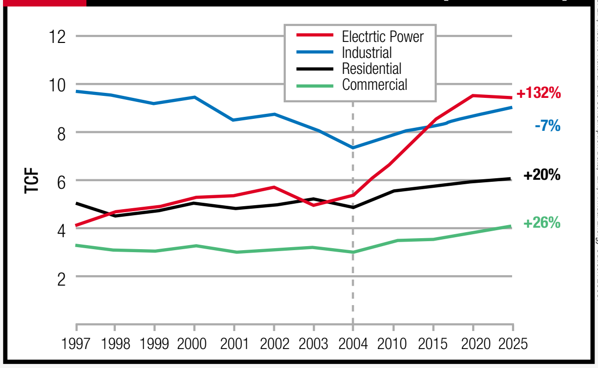
Source: EIA, *Annual Energy Outlook 2005*

FIG. 3 **U.S. CAPACITY ADDITIONS BY ON-LINE DATE**



Sources: EIA, Form 860 for 2003; EIA, *Electric Power Monthly*, November 2004, Table ES3.

FIG. 4 **NATURAL GAS CONSUMPTION BY SECTOR (1997-2025)**

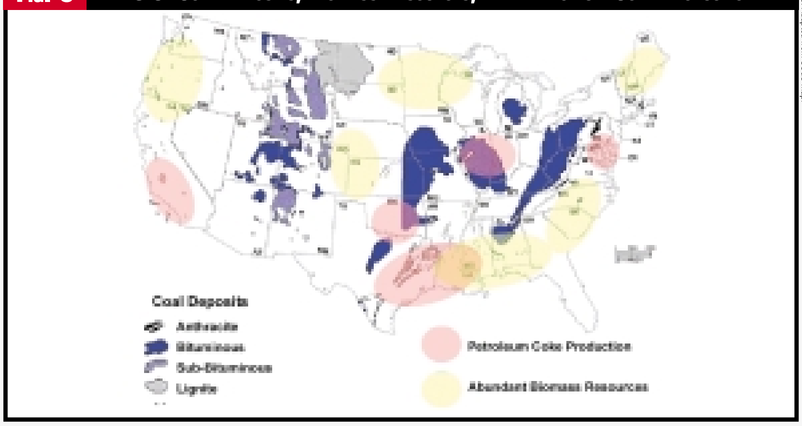


Sources: EIA, Historic Natural Gas Consumption Data; EIA, *Annual Energy Outlook 2005*.

world—approximately 25 percent of world supplies and more than a 250-year supply at current consumption rates.[9] The United States also has abundant biomass resources and produces large quantities of petroleum coke residue from refinery operations (*see Figure 5*).

Effectively using these domestic resources to fuel gasification technology is critical for supporting U.S. energy security and fulfilling the national need for secure, clean, and affordable electricity.— ***WGR, MRW, and DCA***

FIG. 5 **U.S. COAL DEPOSITS, BIOMASS RESOURCES, AND PETROLEUM COKE PRODUCTION**



Source: Adapted from USGS map.

Endnotes

1. See Energy Information Administration at: *http://tonto.eia.doe.gov/dnav/ng/hist/n9190us3a.htm*
2. See Energy Information Administration at: *http://tonto.eia.doe.gov/dnav/ng/hist/n3050us3M.htm*; see also *National Petroleum Council, Balancing Natural Gas Policy—Fueling Demands of a Growing Economy*, Washington, D.C., Sept. 2003, p. 22.
3. See Energy Information Administration, *Annual Energy Outlook 2005*, Table A14.
4. Energy Information Administration, Form EIA 860, Annual Electric Generator Report, 2002.
5. The economic consequences of high prices are described in the *House Speaker's Task Force for Affordable Natural Gas* report, which states: "Because domestically produced natural gas is so vital to our nation's energy balance, rising prices make our nation less competitive. When prices rise, factories close. Good, high-paying jobs are imported overseas. Today's high natural gas prices are doing just that. We are losing manufacturing jobs in the chemicals, plastics, steel, automotive, glass, fertilizer, fabrication, textile, pharmaceutical, agribusiness and high tech industries." House Energy and Commerce, The Task Force for Affordable Natural Gas, *Natural Gas: Our Current Situation*, Sept. 30, 2003.
6. American Chemistry Council, "Energy Costs Destroying Chemical Manufacturing Competitiveness," (Nov. 3, 2004 news release).
7. The Fertilizer Institute, "Fertilizer Industry Weights in on Energy Crisis at Natural Gas Summit,"(June 26, 2003 news release).
8. Department of Energy, National Energy Technology Laboratory, "Tracking New Coal-Fired Power Plants: Coal's Resurgence in Electric Power Generation," Sept. 3, 2004.
9. National Mining Association, "Fast Facts About Coal," *http://www.nma.org/statistics*, Sept. 9, 2003.

A National Gassification Strategy

(Continued from p. 69)

is at our fingertips, but it will require Congress to recognize and act on its need for greater energy independence and adopt a National Gasification Strategy that stimulates robust, near-term investment. [*Sidebar, endnotes cont. p.72*]

William Rosenberg is a senior fellow at the Kennedy School of Government, Harvard University, and professor in the Department of Engineering and Public Policy, Carnegie Mellon. Previously, he served as chairman, Michigan Public Service Commission; assistant administrator for Energy Resource Development, Federal Energy Administration; and assistant administrator for Air and Radiation, EPA. Michael Walker is a consultant who has spent the past 11 years working on environmental and regulatory issues affecting the electric power industry. Dwight Alpern is an attorney advisor at the Clean Air Markets Division, EPA, and previously was an attorney at FERC and the DOE.

RECONCILING COAL AND ENVIRONMENTAL PROTECTION

The environmental concerns associated with coal-fired power plants are well documented and a significant factor that stands in the way of new pulverized coal (PC) power plant permitting and construction. PC power plants emit high levels of sulfur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM), mercury (Hg), and carbon dioxide (CO_2). These emissions contribute to local and regional air pollution problems and global climate change concerns. IGCC technology offers the potential to address these air-quality and climate-change concerns.

The emissions performance for pollutants regulated by EPA of the current generation of IGCC plants is better than the performance of the cleanest PC technology, and future generations of IGCC plants will be even cleaner and more efficient. However, perhaps the most significant environmental benefit of gasification is that it provides a technology pathway for addressing CO_2 emissions. The need for progress on climate change is a theme being echoed by major electric generating companies. For example, Cinergy's 2004 annual report was largely dedicated to the issue of global warming, and in April, 2005, Duke Energy indicated its support for an economy-wide federal carbon tax.[1]

The National Commission on Energy Policy underscored the importance of gasification and IGCC technology for addressing CO_2 emissions, stating:

> Coal-based integrated gasification combined-cycle (IGCC) technology, which—besides having lower pollutant emissions of all kinds—can open the door to economic carbon capture and storage, holds great promise for advancing national as well as global economic, environmental, and energy security goals. The future of coal and the success of greenhouse gas mitigation policies may well hinge to a large extent on whether this technology can be successfully commercialized and deployed over the next 20 years.[2]

By adding water-gas shift reactors and physical absorption processes to the syngas treatment system (processes that are commercially proven in industrial applications), CO_2 can be removed from syngas (and pure hydrogen produced) prior to combustion. Several studies have shown this to be a more cost-effective approach to CO_2 capture with proven technology than post-combustion CO_2 capture on conventional coal combustion technologies.[3]

In addition, because it can easily produce streams of pure hydrogen, gasification could be a vital bridge for moving toward advanced hydrogen technologies such as fuel cells and zero-emissions fossil-fuel power generation that may ultimately provide the keys to addressing global climate change.

DOE's FutureGen and Vision 21 programs aim to develop technologies of the future that will provide for coal-fueled facilities that are 60 percent efficient (compared with the 38 to 42 percent efficiency of new coal power plants today) and have zero emissions. Gasification is a foundation technology for achieving these goals because it can produce pure hydrogen to power zero-emissions fuel cell technologies.— ***WGR, MRW, and DCA***

Endnotes

1. See Cinergy 2004 Annual Report; Greenwire, "Duke Energy Endorses Carbon Dioxide Tax," April 7, 2005.
2. National Commission on Energy Policy (NCEP), Ending the Energy Stalemate, A Bipartisan Strategy to Meet America's Energy Challenges, Washington, D.C., Dec. 2004, p. 51.
3. See NETL, Major Environmental Aspects, Dec. 2002 (citing DOE—EPRI Report 1000316, Dec. 2000.) See also Jeremy David and Howard Herzog, The Cost of Carbon Capture, 2000.

Endnotes

1. More detailed descriptions of the ideas presented in this article are provided in: Rosenberg, William G., Dwight C. Alpern, Michael R. Walker, Deploying IGCC Technology in this Decade with 3Party Covenant Financing, Kennedy School of Government, Harvard University, May 2005 Revision; and Rosenberg, William G., Dwight C. Alpern, Michael R. Walker, *National Gasification Strategy: Gasification of Coal & Biomass as a Domestic Gas Supply Option*, Kennedy School of Government, Harvard University, May 2005 Revision. Both papers are available at: *www.ksg.harvard.edu/bcsia/enrp*.
2. *Wisconsin Electric Power Co., 228 PUR4th 444, 2003 WL 22663829 (Wisc. P.S.C. Nov. 10, 2003).*
3. See S.726, The Natural Gas Price Reduction Act, introduced April 6, 2005; See also S.727, Tax Incentives For The Natural Gas Price Reduction Act Of 2005, introduced April 6, 2005.
4. Rosenberg, William G., Dwight C. Alpern, Michael R. Walker, Deploying IGCC Technology in this Decade with 3Party Covenant Financing, Kennedy School of Government, Harvard University, May 2005 Revision. (available at: *www.ksg.harvard.edu/bcsia/enrp*).
5. *Id.* at Vol. I, p. 14.

Attachment 6

Salazar National Gasification Strategy Bill

109TH CONGRESS
1ST SESSION

S. ______

To establish a Federal incentive program as part of a national gasification strategy to stimulate commercial deployment of integrated gasification combined cycle and industrial gasification technology.

IN THE SENATE OF THE UNITED STATES

Mr. SALAZAR introduced the following bill; which was read twice and referred to the Committee on ______________

A BILL

To establish a Federal incentive program as part of a national gasification strategy to stimulate commercial deployment of integrated gasification combined cycle and industrial gasification technology.

Be it enacted by the Senate and House of Representatives of the United States of America in Congress assembled,

SECTION 1. SHORT TITLE.

This Act may be cited as the "National Gasification Strategy Act of 2005".

SEC. 2. PURPOSE.

The purpose of this Act is to establish a Federal incentive program as part of a national gasification strategy to stimulate commercial deployment of integrated gasification combined cycle and industrial gasification technology in order to—

(1) develop gasification as a gas supply option that provides the energy equivalent of 1,500,000,000,000 cubic feet of natural gas;

(2) promote the use of domestic coal, biomass, petroleum coke, and other domestic fuel resources;

(3) reconcile coal use and environmental protection;

(4) reduce the demand pressure on domestic natural gas prices and supply by promoting the use of gas derived from domestic coal and biomass and other domestic fuel resources for electric generation and industrial use;

(5) provide affordable and reliable electricity and gas supply;

(6) promote the position of the United States as a global leader in advanced gasification technology and carbon capture and storage technology; and

(7) accomplish the goals described in paragraphs (1) through (6) while minimizing the burden on the Federal budget.

SEC. 3. DEFINITIONS.

In this Act:

(1) BIOMASS.—

(A) IN GENERAL.—The term ''biomass'' means—

(i) an animal, agricultural, or plant waste; and

(ii) forestry materials, including wood wastes, forest thinnings, and the residuals and byproducts of wood harvest or conversion.

(B) EXCLUSION.—The term ''biomass'' does not include paper that is commonly recycled.

(2) CARBON CAPTURE READY.—The term ''carbon capture ready'' means, with respect to a project, having a design that is determined by the Secretary to be capable of accommodating the equipment likely to be necessary to capture the carbon dioxide that would otherwise be emitted in flue gas from the project.

(3) IGCC PROJECT.—The term ''IGCC project'' means an integrated gasification combined cycle project with respect to which, during the term of the loan guarantee under the program for the project or,

in the case of a grant, the useful life of the project, as determined by the Secretary—

(A) except as provided in section 4(c)(4), coal will account for at least 75 percent of annual heat input; and

(B) electricity will account for at least 75 percent of annual useful energy output.

(4) INDUSTRIAL GASIFICATION PROJECT.—The term "industrial gasification project" means a project with respect to which, during the term of the loan guarantee under the program for the project or, in the case of a grant, the useful life of the project, as determined by the Secretary—

(A) coal, biomass, or petroleum residues, in any combination, may account for annual fuel heat input; and

(B) electricity will account for less than 75 percent of annual useful energy output.

(5) NATURAL GAS COMBINED CYCLE POWER PLANT.—The term "natural gas combined cycle power plant" means a system that—

(A) comprises 1 or more combustion turbines, heat recovery steam generators, and steam turbines; and

(B) combusts at least 90 percent natural gas for the annual fuel heat input of the system for any year.

(6) PROGRAM.—The term ''program'' means the Federal incentive program established under section 4(a).

(7) PROJECT.—The term ''project'' means—

(A) any combination of equipment located at a specific site for an IGCC project or industrial gasification project that is used—

(i) to gasify coal, biomass, or petroleum residues;

(ii) to remove pollutants from the resulting gas;

(iii) to use the resulting gas for industrial purposes or burn the resulting gas in a turbine to generate electricity; and

(iv) to remove pollutants from the resulting flue gas;

(B) a combined cycle power plant refueled using the equipment described in subparagraph (A) that is in existence on the date of enactment of this Act; or

(C) an industrial gasification project that uses the equipment described in subparagraph (A).

(8) SECRETARY.—The term ''Secretary'' means the Secretary of Energy.

(9) TOTAL PLANT INVESTMENT.—The term ''total plant investment'' means, with respect to a project, the aggregate amount of—

(A) engineering, procurement, and construction costs;

(B) costs incurred by the owner of the project in developing and starting up the project;

(C) construction financing costs; and

(D) any contingency reserves.

SEC. 4. FEDERAL INCENTIVE PROGRAM.

(a) ESTABLISHMENT.—Not later than 1 year after the date of enactment of this Act, the Secretary shall establish a Federal incentive program under which the Secretary shall provide loan guarantees and grants for projects selected in accordance with this Act.

(b) ELIGIBLE PROJECTS.—The owner of a proposed project that seeks to receive a loan guarantee or grant for a project under the program shall submit to the Secretary, in accordance with such procedures as the Secretary shall establish by regulation, an application that demonstrates that the project—

(1) if the proposed project is an IGCC project, will be—

(A) a new power plant;

(B) a repowering of an existing coal-fired power plant; or

(C) a refueling of an existing natural gas combined cycle power plant;

(2) will comply with enforceable emission limitation requirements, in addition to any other applicable Federal or State emission limitation requirements, that the project attain at least—

(A) total sulfur dioxide emissions in flue gas from the project that do not exceed 0.04 lb/mmBtu;

(B) a 95-percent removal rate (including any fuel pretreatment) of mercury from the coal-derived gas, and any other fuel, combusted by the project;

(C) total nitrogen oxide emissions in the flue gas from the project that do not exceed 0.05 lb/mmBtu; and

(D) total particulate emissions in the flue gas from the project that do not exceed 0.01 lb/mmBtu;

(3) will be carbon capture ready;

(4) in the case of an application for a loan guarantee, will have an assured revenue stream and other credit enhancements that provide credit and Federal budget scoring that is acceptable to the Secretary and the Office of Management and Budget (in accordance with the purpose and goals described in section 2); and

(5) has obtained—

(A) approval by the appropriate regulatory commission of the recovery of the cost of the project; or

(B) a power purchase agreement, or a letter of intent relating to such an agreement, that has been approved by the board of directors or appropriate oversight authority of, and executed by, a creditworthy purchasing party, as determined by the Secretary.

(c) SELECTION OF PROJECTS.—

(1) IN GENERAL.—The Secretary shall—

(A) establish, by regulation, review and approval criteria and procedures for selecting a proposed project to receive a loan guarantee or grant under the program; and

(B) select projects for receipt of loan guarantees and grants in accordance with those criteria.

(2) DIVERSITY.——In applying the review and approval criteria to each proposed project, the Secretary shall ensure, to the maximum extent practicable, that the portfolio of projects for which loan guarantees or grants are provided under the program will result in—

(A) gasification of a diversity of coal types (including subbituminous coal) and other fuel types; and

(B) a geographic diversity of projects.

(3) LIMITATION.—The Secretary shall issue a loan guarantee for a proposed project only if the loan guarantee for the project under the program has a budget score under the Federal Credit Reform Act of 1990 (2 U.S.C. 661 et seq.) that, as determined by the Office of Management and Budget, does not exceed the product obtained by multiplying—

(A) an amount equal to the total plant investment in the project; and

(B) such percentage level for budget scoring as shall be established by the Office of Management and Budget in accordance with the purpose of this Act.

(4) CERTAIN IGCC PROJECTS.—The Secretary may select under this subsection not more than 2 IGCC projects with respect to which, during the term of the loan guarantee under the program for the project or, in the case of a grant, the useful life of the project, as determined by the Secretary, biomass or petroleum residues may account for at least 75 percent of annual heat input.

(d) COMMENCEMENT OF CONSTRUCTION.—The Secretary shall require construction on a project for which a loan guarantee or grant is provided under the program to commence not later than the date that is 3 years after the date of issuance of the loan guarantee or grant.

(e) PROVISION OF LOAN GUARANTEES AND GRANTS.—

(1) LOAN GUARANTEES.—Each loan guarantee provided for a project under the program shall—

(A) cover up to 80 percent of the total plant investment in a project selected under subsection (c), on the conditions that—

(i) the owner of the project provides equity investment in the project of at least 20 percent of the total plant investment; and

(ii) for purposes of applying the percentage requirements under clause (i), the amount of the total plant investment shall be reduced by the dollar amount of any Federal grant provided for the project under the program;

(B) apply to the long-term debt obligations for the project, which obligations—

(i) may, at the discretion of the Secretary, be nonrecourse obligations; and

(ii) shall have a term of up to 30 years; and

(C) be backed by the full faith and credit of the United States.

(2) GRANTS.—

(A) IN GENERAL.—Each Federal grant provided for a project under the program shall—

(i) be provided for a project only to the owner of the project, in whole or in part, that is a Federal, State, or local governmental entity or rural electric cooperative; and

(ii) cover not more than 20 percent of the portion of total plant investment contributed by the Federal, State, or local governmental entity or rural electric cooperative for the project.

(B) EXCEPTION.—The limitation described in subparagraph (A)(ii) shall not apply to any portion of investment or operating costs relating to the capture and storage of carbon dioxide.

(3) LIMITATIONS.—The Secretary may provide, or certify an eligible project to receive, loan guarantees or grants for a project if the aggregate scored value (as determined by the Office of Management and Budget) of incentives made available to IGCC projects and industrial gasification projects does not exceed—

(A) $200,000,000 for each project receiving incentives under this title; and

(B) 20 percent of the total plant investment of each project receiving incentives under this title.

(f) REGULATIONS.—Not later than 1 year after the date of enactment of this Act, the Secretary shall issue regulations to carry out the program, including, at the discretion of the Secretary, regulations that establish—

(1) conditions for the disbursement of funds for loan guarantees or grants provided under the program;

(2) procedures and requirements for monitoring and reporting the status of projects, or of research, development, demonstration, or commercial deployment under projects, for which loan guarantees or grants are provided under the program;

(3) procedures for taking actions to restrict the impact on the Federal budget in the event of foreclosure of a project provided a loan guarantee or grant under the program; and

(4) application, insurance, and other fees, including schedules for the payment or collection of the fees, to cover administrative costs incurred, and the burden placed on the Federal budget, in carrying out the program.

(g) AUTHORIZATION OF APPROPRIATIONS.—

(1) CARBON CAPTURE AND DEMONSTRATION PROJECTS.—

(A) IN GENERAL.—Subject to subparagraph (B), there is authorized to be appropriated for providing loan guarantees or grants for projects involving the capture or storage of carbon dioxide under the program—

(i) $250,000,000 for fiscal year 2006;

(ii) $150,000,000 for each of fiscal years 2007 through 2009; and

(iii) $100,000,000 for each of fiscal years 2010 through 2012.

(B) SPECIFIC PROJECTS.—Of each amount made available under subparagraph (A) for a fiscal year—

(i) ⅓ of the amount shall be used for providing loan guarantees or grants for projects involving research, development, and demonstration of technology for—

(I) the capture and storage of carbon dioxide;

(II) biomass gasification; or

(III) gasification of subbituminous or lignite coals; and

(ii) ⅔ of the amount shall be used for providing loan guarantees or grants to support the commercial deployment of technology for capture and storage of carbon dioxide from projects for which loan guarantees or grants are provided under the program.

(2) IGCC AND INDUSTRIAL GASIFICATION PROJECTS.—

(A) AUTHORIZATION OF APPROPRIATIONS.—Subject to subparagraph (B), there is authorized to be appropriated for providing loan guarantees or grants for IGCC projects and industrial gasification projects under the program—

(i) $500,000,000 for fiscal year 2006;

(ii) $300,000,000 for each of fiscal years 2007 through 2009; and

(iii) $200,000,000 for each of fiscal years 2010 through 2012.

(B) SPECIFIC PROJECTS.—Of each amount made available under subparagraph (A) for a fiscal year—

(i) not more than 50 percent shall be used for providing loan guarantees for industrial gasification projects; and

(ii) the remaining amount shall be used for providing loan guarantees or grants for IGCC projects, of which—

(I) at least ⅓ of the amount shall be used for providing loan guarantees or grants for IGCC projects that involve existing natural gas combined cycle power plants refueled using gasification of coal, biomass, or petroleum residues; and

(II) not more than $30,000,000 may be used for providing Federal grants for IGCC projects.

SEC. 5. INTEGRATED WESTERN COAL/HIGH ALTITUDE CARBON MINIMIZATION-SEQUESTRATION ENERGY SYSTEM.

(a) IN GENERAL.—Subject to the availability of appropriations, the Secretary shall provide financial assistance (including grants and loan guarantees) for a project to produce energy from coal mined in the western United States using appropriate advanced integrated gasification combined cycle technology, including repowering of existing facilities, that minimizes and offers the potential to sequester carbon dioxide emissions.

(b) SPECIFICATIONS.—The project—

(1) may be built in stages;

(2) shall have a combined output of at least 100 megawatts;

(3) shall be located in a western State at an altitude greater than 4,000 feet; and

(4) shall use coal with an energy content of not more than 9,000 Btu/lb.

(c) FEDERAL SHARE.—The Federal share of the cost of the project shall not exceed 50 percent.

(d) TECHNICAL CRITERIA.—Technical criteria for a project under a clean coal power initiative carried out by the Secretary shall apply to the construction of the project.

(e) FEES.—The Secretary may establish by regulation application, insurance, and other fees, including schedules for the payment or collection of the fees, to cover administrative costs incurred, and the burden placed on the Federal budget, in carrying out this section.

Attachment 7

Summary of Energy Policy Act of 2005 Gasification Incentives

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Gasification Incentives in Energy Policy Act of 2005

On August 8, 2005 President Bush signed the Energy Policy Act of 2005 into law. The Act contains significant incentives to accelerate deployment of gasification technologies for both power generation and industrial use. As summarized below, the primary incentives include cost share programs (up to 50% direct grants), investment tax credits (20%), and federal loan guarantees (up to 80%) that in some cases (specifically the tax credits and loan guarantees) can be used in combination.

The loan guarantee and tax credit deployment incentives will make production of syngas extremely competitive with natural gas for industrial uses and enable integrated gasification combined cycle (IGCC) power plants to produce electricity at prices below conventionally financed pulverized coal or natural gas power plants (see attached charts). Gasification technology deployment will enable the U.S. to take advantage of its vast domestic resources of coal, biomass, and petroleum residues, enhance energy security, and establish a technological pathway for addressing CO_2 emissions.

We are grateful to the many people that have assisted our project at the Kennedy School of Government over the past two years to develop and refine ideas around a 3Party Covenant loan guarantee program and National Gasification Strategy. We are thrilled to see the fundamental principals behind those proposals incorporated into the final bill and look forward to working with our many colleagues to assist in their timely implementation.

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Overview of Key Incentive Provisions

TITLE IV--COAL

- **Subtitle A--Clean Coal Power Initiative: A**uthorizes $200 million per year from 2006 to 2014 ($1.8 billion) to continue the CCPI, which is a federal government cost share program to demonstrate advanced clean coal technologies. Of the 1.8 billion authorized, 70% of the funds are to be used on coal-based gasification technologies ($1.26 billion). Federal cost-share grants are available under this program for up to 50 percent of the cost of projects involving demonstration of commercial applications of technology and for up to 80% for research and development projects. DOE is required to submit a report to Congress by March 31, 2007 that details how proposals will be solicited and evaluated and that establishes technical milestones for the program.
- **Subtitle B—Clean Power Projects:** Identifies a number of specific gasification projects to receive federal assistance, as follows:

  Sec. 411—Loan guarantees for a project using coal of less than 7,000 btu/lb located in the Upper Great Plains;

  Sec. 412—A direct loan not to exceed $80 million to place a clean coal technology facility in service near Healy, Alaska;

  Sec. 413—Up to a 50 percent cost share for a Western IGCC demonstration project designed to use western coals and located at an elevation above 4,000 feet;

  Sec. 414—Loan guarantees for an IGCC project of at least 400 MW that will produce power at competitive rates in a deregulated energy market without any ratepayer subsidies; and

  Sec. 415—Authorization to provide loan guarantees for 5 petroleum coke gasification projects.

  Sec. 417—$85 million in grant support to three Universities to develop facilities to evaluate commercial and technical viability of producing transportation fuels using Illinois basin coal and to develop a Gasification Products Text Center to test systems to produce 500 gallons of Fischer-Tropsch transportation fuels per day.
- **Subtitle C--Clean Air Coal Program**: Amends the Energy Policy Act of 1992 to create a new Title XXXI—Clean Air Coal Program. The new Title authorizes $2.5 billion for a program to assist commercial deployment of advanced coal technologies through loans, cost sharing, or cooperative agreements. Projects can include gasification technologies and advanced combustion technologies. Cost-sharing is not to exceed 50% of project costs and projects selected are to include processes the Secretary determines will be cost-effective and could substantially contribute to meeting national environmental or energy needs. Priority is to be given to projects that use processes that have been developed and demonstrated, but are not yet cost competitive, and achieve greater efficiency and environmental

performance. To the extent practical, between 25 and 75% of the funding should support projects for the sole purpose of producing electricity.

TITLE V—INDIAN ENERGY: This Title creates a new Office of Indian Energy Policy and Programs in DOE to promote and facilitate Indian energy development and efficient use. The Title provides authorization of an unspecified amount for the Secretary of Interior to make grants and loans to assist in development of energy resources and provides authorization of $220 million for Director of the new Office of Indian Energy Policy and Programs to make grants to facilitate energy resource development. It also provides for DOE to make up to $2 billion of loan guarantees for up to 90% of any unpaid principal and interest due on any loan made to an Indian tribe for energy development. The Title does not specify use of gasification or any other technology, but gasification projects on Indian lands undertaken in cooperation with Indian tribes could qualify for grant or loan guarantee assistance under the title.

TITLE IX—RESEARCH & DEVELOPMENT: Establishes funding for a Research and Development programs for a variety of technologies, including advanced coal and power systems and carbon capture technologies. Authorizations for funding the coal and related technologies program total $1.137 billion in years 2007-2009. Significant gasification related technology research and development should occur under this program.

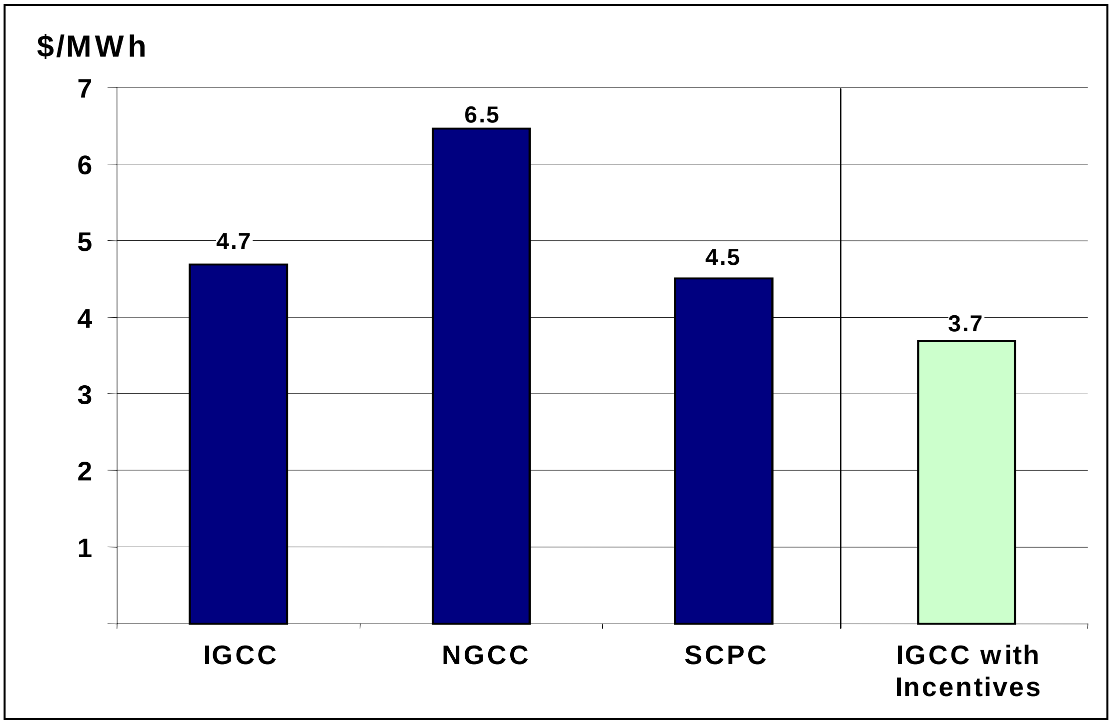
TITLE XIII—ENERGY POLICY TAX INCENTIVES: Section 1307 of Title XIII creates investment tax credits (ITC) for IGCC, industrial gasification, and advanced coal combustion facilities by inserting two new sections after section 48 of the tax code. The incentives enable IGCC projects to receive a 20 percent ITC (the language specifically indicates eligible investments are those made for gasification and coal handling equipment, which may not be interpreted to include investments in turbines or other IGCC power block equipment). The program may provide up to $800 million of credits to IGCC projects (thereby supporting $4 billion of project investment). Industrial gasification projects may receive a 20% ITC and the program may provide up to $350 million of credits (supporting $1.75 billion of project investment).

TITLE XVII INCENTIVES FOR INNOVATIVE TECHNOLOGIES: Establishes a loan guarantee program to provide up to 80% federal loan guarantees to gasification and other eligible technologies. The Title includes eligibility requirements for IGCC projects, including emissions performance criteria, availability of an "assured revenue stream" to cover project capital and operating costs, and a design capable of accommodating carbon capture equipment. In addition to IGCC, the Title identifies industrial gasification projects and petroleum coke gasification projects as priorities. It also includes provisions for project owners to pay for the federal cost of scoring their loan guarantee, which will enable the program to provide guarantees even in the absence of appropriations. No cap is established on the amount of funds that could be used to score loan guarantees under the Title, but specific appropriations will be required for budget scoring.

Summary of Energy Policy Act of 2005 Gasification Incentives

Title	Section	Type of Incentive	Authorization
Title IV— Coal	*Subsection A—* Clean Coal Power Initiative	Cost-share grants up to 50%	$1.26 billion (for gasification technologies)
	Subsection B— Clean Power Projects	Loan guarantees and grants for specific projects	Authorized funding as needed ($80 million specified for 1 project)
	Subsection C— Coal & Related Programs	Cost-share grants up to 50%	$2.5 billion (available for gasification and advanced combustion technologies)
Title V— Indian Energy	Sections 501-503	Grants, direct loans, loan guarantees	$220 million for grants Authorizations for additional funding for grants, direct loans and loan guarantees (total guaranteed not to exceed $2 billion)
Title XI— Research & Development	Sections 961-962	Grants for research, development, demonstration and commercial applications	$1.137 billion (available in 2007-2009)
Title XIII— Energy Policy Tax Incentives	Section 1307 (Adding new Sections 48A & 48B to tax code)	20% ITC for IGCC gasification island investments 20% ITC for industrial gasification investments	$800 million for IGCC $350 million for industrial gasification
Title XVII— Incentives for Innovative Technologies	Sections 1701-1703	80% federal loan guarantees	Authorized funding as needed. (In absence of appropriations, owners can cover cost of loan guarantees)

Estimated Energy Costs of IGCC with 80% loan guarantee and 20% ITC vs. conventionally financed fossil plants



Cost of Syngas with Federal Incentives vs. Natural Gas Price