Opportunities to Expedite the Construction of New Coal-Based Power Plants

Chair:
Thomas G. Kraemer
Burlington Northern Santa Fe Railway Co.

Vice Chair:
Georgia Nelson
Midwest Generation EME, LLC

Study Co-Chairs:
Robert Card
U.S. Undersecretary of Energy

Dr. E. Linn Draper, Jr.
American Electric Power Co.

Technical Work Group Chair:
Michael J. Mudd
American Electric Power Co.

Library of Congress Catalog # 2005920127

THE NATIONAL COAL COUNCIL

Thomas G. Kraemer, Chairman

Robert A. Beck, Executive Director

U.S. DEPARTMENT OF ENERGY

Spencer Abraham, Secretary of Energy

OPPORTUNITIES TO EXPEDITE THE CONSTRUCTION OF NEW COAL-BASED POWER PLANTS

Table of Contents

Preface

The National Coal Council is a private, nonprofit advisory body, chartered under the Federal Advisory Committee Act.

The mission of the Council is purely advisory: to provide guidance and recommendations as requested by the U.S. Secretary of Energy on general policy matters relating to coal. The National Coal Council is forbidden by law from engaging in lobbying or other such activities. The National Coal Council receives no funds or financial assistance from the Federal Government. It relies solely on the voluntary contributions of members to support its activities.

The members of The National Coal Council are appointed by the Secretary of Energy for their knowledge, expertise and stature in their respective fields of endeavor. They reflect a wide geographic area of the U.S. and a broad spectrum of diverse interests from business, industry and other groups, such as:

- large and small coal producers;
- coal users such as electric utilities and industrial users;
- rail, waterways, and trucking industries as well as port authorities;
- academia;
- research organizations;
- industrial equipment manufacturers;
- state government, including governors, lieutenant governors, legislators, and public utility commissioners;
- consumer groups, including special women's organizations;
- consultants from scientific, technical, general business, and financial specialty areas;
- attorneys;
- state and regional special interest groups; and
- Native American tribes.

The National Coal Council provides advice to the Secretary of Energy in the form of reports on subjects requested by the Secretary and at no cost to the Federal Government.

Abbreviations

AEO	Annual Energy Outlook
AFBC	Atmospheric fluidized bed combustion
AMM	Abandoned mine methane
API	American Petroleum Institute
ABCT	Best available control technology
Bcf	Billion cubic feet
Btu	British thermal units
Btu/kWh	British thermal units per kilowatt-hour
CAA	Clean Air Act
CBM	Coalbed methane
CCS	CO_2 capture and storage
CCT	Clean Coal Technology
CDM	Clean Development Mechanism
CFB	Circulating fluidized bed
CMM	Coal mine methane
CO	Carbon monoxide
CO_2	Carbon dioxide
COE	Cost of electricity
DOE	Department of Energy
DSM	Demand side management
EEI	Edison Electric Institute
EHE	External heat exchanger
EIA	Energy Information Administration
EIIP	Emission Inventory Improvement Program
EPA	Environmental Protection Agency
EPRI	Electric Power Research Institute
FBC	Fluidized bed combustor
FE	Fossil energy
FGD	Flue gas desulfurization
FY	Fiscal year
GCCI	Global Climate Change Initiative
GDP	Gross domestic product
GHG	Greenhouse gas
GW	Gigawatts
GWP	Global warming potential
H_2	Hydrogen
IGCC	Integrated gasification combined cycle
IPCC	Intergovernmental Panel on Climate Change
JI	Joint implementation
KW	Kilowatt
kWh	Kilowatt-hour
lb/MBtu	Pounds of emissions per million Btu of heat input
lb/MWh	Pounds of emissions per megawatt-hour generated
LHV	Lower heating value
LNB	Low NO_x burners
LNG	Liquified natural gas
MBtu	Million Btu
MMTCE	Million metric tons carbon

$MTCO_2$	Million tons of carbon dioxide
MW	Megawatts
MWh	Megawatt-hour
N_2O	Nitrous oxide
NCC	National Coal Council
NETL	National Energy Technology Laboratory
NGCC	Natural Gas Combined Cycle
NMA	National Mining Association
NO_x	Nitrogen oxides
NSR	New Source Review
O&M	Operating and maintenance
PC	Pulverized coal
PFBC	Pressurized fluidized bed combustion
PFBCwTC	Pressurized fluidized bed combustion with topping combustor
PPM	Parts per million
PPMV	Parts per million by volume
PSI	Pounds per square inch
R&D	Research and development
RD&D	Research, Development and deployment
SC	Supercritical
SCR	Selective catalytic reduction
SNCR	Selective non-catalytic reduction
SO_2	Sulfur dioxide
TPY	Tons per year
UNFCCC	United Nations Framework Convention on Climate Change
USC	Ultra-supercritical
VAC	Ventilation air methane
WBCSD	World Business Council for Sustainable Development
WRI	World Resources Institute

Principle Contributors

Sy Ali, Clean Energy Consulting Group

Tom Altmeyer, Arch Coal, Inc.

Dan Arvizu, CH2M Hill

Eric Balles, Babcock Borsig Power, Inc.

Janos Beer, Massachusetts Institute of Technology

George Booras, Electric Power Research Council

Fred Bush, Savage Industries

Hank Courtright, Electric Power Research Council

Stu Dalton, Electric Power Research Institute

David Denton, Eastman Gasification Services Co.

Bill DePriest, Sargent & Lundy

E. Linn Draper, American Electric Power Co.

Michael Durham, ADA Environmental Services

Richard Eimer, Dynegy Marketing & Trade

Joel Friedlander, The North American Coal Corporation

Janet Gellici, American Coal Council

Tom Grahame, Department of Energy

Mike Gregory, The Northern American Coal Corporation

Jerry Hollinden, URS Corporation

Neville Holt, Electric Power Research Institute

Steve Jenkins, URS Corporation

Judy Jones, Public Utilities Commission of Ohio

Jeff Knitter, WeEnergies

Klaus Lambeck, Ohio Public Utilities Commission

Ron Litzinger, Edison Mission Energy

John Long, Constellation Energy

Mike Mudd, American Electric Power Company

Ram Narula, Bechtel Power Corporation

Georgia Nelson, Midwest Generation

Fredrick Palmer, Peabody Energy

Jack Parkes, Electric Power Research Institute

Bob Pearson, CH2M Hill

Robert Purgert, Energy Industries of Ohio

Peter Rigby, Standard & Poor’s

Lars Scott, Peabody Energy

John Vella, Edison Mission Energy

Jerry Weeden, NiSource

Kim Wissman, Ohio Public Utilities Commission

Mona Yee, Fitch Ratings

Executive Summary

Purpose

By letter dated December 3, 2003 (see Appendix E), U.S. Secretary of Energy Spencer Abraham requested that The National Coal Council prepare a study identifying "which opportunities could expedite the construction of new coal-fired electricity generation." He also requested that the Council "examine opportunities and incentives for additional emissions reduction including evaluating and replacing the oldest portion of our coal-fired power plant fleet with more efficient and lower emitting coal-fired plants."

The Secretary expressed his belief that this report "will serve as a blueprint for industry while acting as a guide to promote the construction of new coal-fired facilities."

The Council accepted the Secretary's request and formed a study group of experts in the field to conduct the work and prepare a report. The list of participants on this group can be found in Appendix D of this report.

Findings

The National Coal Council finds the following. Each finding is of equal importance.

***Coal is the fuel of choice now, and will remain so into the future*.**

Coal-based power plants produce greater than 50% of all the electricity in the United States. It will remain the primary fuel source for electricity generation for the foreseeable future. It is secure, affordable and environmentally compatible. The country has about 250 years of supply in reserve at the present rate of consumption. Through continued research, development and deployment of new technologies, coal will continue to fuel low-cost electricity and to demonstrate continued environmental improvements.

Natural gas has been the dominant fuel for new power plants in the last decade.

Over the past decade, the availability of low cost natural gas and increased competition in the electric generation market, when combined with certain federal energy polices of the 1990s promoting the use of natural gas, has resulted in the choice of natural gas over coal as the fuel for most new generating plants. The net effect of the 1990s policies was to stimulate natural gas demand through its use to generate electricity to the detriment of American citizens who use it for home heating purposes and industries which rely on natural gas for their primary feedstock or other uses.

Coal provides a pathway for greater energy independence.

As the demand for electricity continues to increase, the Energy Information Administration (EIA) and others have forecasted large increases in electricity generation using natural gas as a fuel. With the United States' best prospect for increasing natural gas supplies coming from foreign sources including Canadian imports and liquefied natural gas (LNG), a better alternative for energy independence would be to build more new, domestically supplied coal-based power plants.

There is renewed interest in using coal to fuel new power plants.

Increases in the price and historical volatility of natural gas supplies, the long-term stability of coal prices, and the financial impacts from a number of financially distressed investments in natural-gas combined-cycle power plants have led to a renewed interest in coal-based electricity generation. Forecasts of natural gas supplies and prices have become more accurate. Supply difficulty and price volatility that have occurred since 2000 and the revised estimates of natural gas reserves by some companies have resulted in more realistic assessments of natural gas supplies and a more reasoned projection of natural gas prices. The National Petroleum Council's 1999 and 2003 reports provide good examples of this increasing accuracy. The higher price forecasts and other warnings in turn make the economic models used to support natural gas-based power plants less attractive.

Generators are expected to remain credit worthy.

Experts in the financial community believe that the outlook for investor-owned electric utilities (IOUs), rural electric cooperative and municipal generators (gencos), and independent generation companies, diversified energy merchants and energy traders, is generally stable. While many IOUs and gencos have either maintained creditworthiness or are well on their way to financial recovery, the investment community believes that many in the merchant or independent power sectors will need time to recover. There are structural differences between the various power producers, and financial issues that impact decisions about whether or not to construct new coal-based facilities differ between the segments.

Permitting delays have been an impediment to building new coal plants.

The length of permitting time, as well as redundant permitting requirements, has created impediments to new construction. These delays are a result of an inefficient permitting process – including a lengthy permitting appeals process – that can delay plants to the point of causing plant cancellations. Even with new coal-based generation meeting, and in some cases exceeding, the most stringent emissions control requirements and efficiency standards, the time from project initiation to start-up is routinely extended due to delays in the permitting process that do not result in any changes to the plant's emissions control systems. These delays result in increased costs and cause uncertainty in the investment community (with higher perceived risks related to developing new coal-based plants).

Environmental regulatory approaches have been an impediment to building new coal plants.

Over the past three decades, the prevailing environmental regulatory approaches have led to the retrofit of high capital cost emissions control technologies at existing coal-based generating plants. In order to avoid the risk of stranded investments and the uncertainty of investing in new plants, power plant operators have taken steps to extend the lives of existing plants. This has also made it more difficult for new plants to enter the electricity market at a price competitive with the overall cost of electricity from older, coal-based plants where the capital cost component of electricity is much less.

Uncertainty about CO_2 emission reductions has been an impediment to the construction of new coal-based power plants.

The uncertainty of future environmental regulations, especially associated with CO_2, has complicated decisions about whether or not to repower or replace existing coal-based generation. This situation is exacerbated by the uncertainty surrounding the broader issue of carbon management.

Incentives are still needed to facilitate the construction of advanced coal-based power plants.

Past incentives have facilitated research, development and demonstration of advanced, clean and efficient coal-based technologies leading to significant advancements in both environmental performance and generation efficiency. However, these technologies require additional support for deployment to achieve significant market penetration.

Lack of a regional planning approach has been an impediment to the construction of new coal-based power plants.

The transitional state-by-state changes in the electric utility industry have resulted in a lack of regional planning. This lack of regional planning has resulted in a short-term focus with small, incremental capacity additions such as natural gas combined cycle plants, rather than coal-based plants that provide enhanced energy security, long-term sustainability and lower overall electricity prices for our nation.

Infrastructure hurdles are impediments to the construction of new coal-based power plants.

Opportunities to install new coal-based power plants in both the short term and in the future are inhibited by several factors that warrant attention on a national environmental and energy policy basis. These factors include the continued failure of the Federal Energy Regulatory Commission (FERC) and the states to deal with transmission congestion, declining engineering resources in the United States, limited availability of skilled construction labor to build new coal-based power plants, declining manufacturing infrastructure in the United States for the fabrication of steel and steel components required for new coal plants, and growing regulatory hurdles to permit and construct new coal mines.

Recommendations

The National Coal Council makes the following recommendations:

Streamline the permitting process.

The Department of Energy, in concert with other appropriate agencies and stakeholders, should develop an integrated, flexible and streamlined approach to environmental regulations and permitting for new, advanced coal-based generation. Operating permits issued under this approach should include assurances that new regulations will not change the permit for a certain fixed period of time after the start-up of the new plant. The Department of Energy (DOE) should then work with the U.S. Environmental Protection Agency (EPA) and others to implement this approach. The goal is to encourage the development and deployment of a domestic, reliable, clean and affordable energy supply. This approach will create incentives and certainty for investments in advanced coal-based generation, while allowing appropriate time for capital stock turnover.

Recognize the strategic importance of integrated gasification combined cycle (IGCC) technology.

The Department of Energy, in concert with other agencies, should create incentives that recognize and reward the potential for integrated gasification combined cycle to replace the use of natural gas in the electricity generation market, produce synthetic gas for poly-generation, and to accelerate progress of the Hydrogen Initiative. This would help stabilize the price of natural gas and free more of it for use in the chemicals, fuels and fertilizer industries, thereby saving domestic jobs in those industries. Also, coal gasification could provide additional feedstock for these industries at a competitive cost.

Recognize the importance of other coal-based technologies.

While IGCC technology is strategically important to the future of coal, the Department of Energy should also support R&D for other advanced coal-based technologies, including advanced pulverized coal-based technology and circulating fluidized bed technology, especially in the areas of carbon capture and ultra-supercritical designs and other efficiency improvements, so that investors in coal-based power plants can choose from a portfolio of attractive technologies.

Encourage regional planning.

The Department of Energy should explore the viability of and encourage a regional planning approach for capacity additions. The regional approach should consider a mechanism to reward investment in efficient and environmentally superior coal-based plants that would have widespread regional benefits and transcend the individual territory of any one state or IOU.

Continue with meaningful R&D.

The Department of Energy should continue research and development work on advanced, efficient and lower-emitting coal-based technologies to ensure that technology continues to keep pace with the goals set forth in the DOE/CURC/EPRI Roadmap. In addition, this effort should include adequate funding and support for flagship programs such as FutureGen and the Hydrogen Initiative.

Continue with technology demonstration.

The Department of Energy should ensure that proper mechanisms and incentives are in place to allow not-yet-mature and first-of-a-kind technologies to be demonstrated in the marketplace so that promising coal-based technologies can be ready for wide-scale deployment through programs such as the Clean Coal Power Initiative.

Provide meaningful incentives for the commercialization and deployment of new advanced coal-based technologies.

The Department of Energy should develop incentives to overcome the risk-adjusted cost differential between options of conventional technologies and new, more efficient, lower-emitting advanced coal-based plants so that these advanced plants can be more expeditiously deployed in the marketplace. The menu available for such incentives includes, but is not limited to, tax incentives, production incentives, public/private cost-sharing, accelerated depreciation, loan guarantees, and federal credit.

Maintain a balanced portfolio of Research & Development, Demonstration and Deployment.

The Department of Energy should recognize the importance of properly funding Research & Development, Demonstration and Deployment and must ensure that proper funding is allocated to all three elements of technology development.

Work with state regulators for cost recovery of new advanced coal-based plants.

The Department of Energy should facilitate the development of a clear regulatory mechanism that will allow investors to recover added costs of replacing some of the older, less efficient existing power plants with new advanced coal-based power plants. Innovative cost recovery proposals should address both state and regional concerns. Additional vehicles could be developed to insure recovery of new capital investment as well as any stranded capital from un-recovered investments associated with the retirement of older facilities. This mechanism would have the opportunity to provide a new incentive to facilitate the construction of new coal-fueled power plants with minimal impact on the federal deficit.

Continue to be a champion for coal.

The Department of Energy should continue to strongly reinforce as often as possible that coal is a vital resource for our country. Coal must be utilized to provide an adequate measure of energy security and reliability, and it has been and will continue to be the major fuel for electricity generation in the country. The use of coal should be encouraged as an alternative feedstock for chemicals and fuels (especially those that are imported), and appropriate incentives and regulatory approaches should be provided to encourage its use in as clean a manner as possible. The use of clean coal technologies should be fostered, encouraged and promoted in other countries where coal is a vital resource. Ever-changing environmental regulations create an impediment to new coal plants. Investment in new plants involves hundreds of millions of dollars and the investment community needs clear and stable rules as a foundation for that investment. Regulations can be and are reinterpreted over time. Stability can only be achieved through legislation.

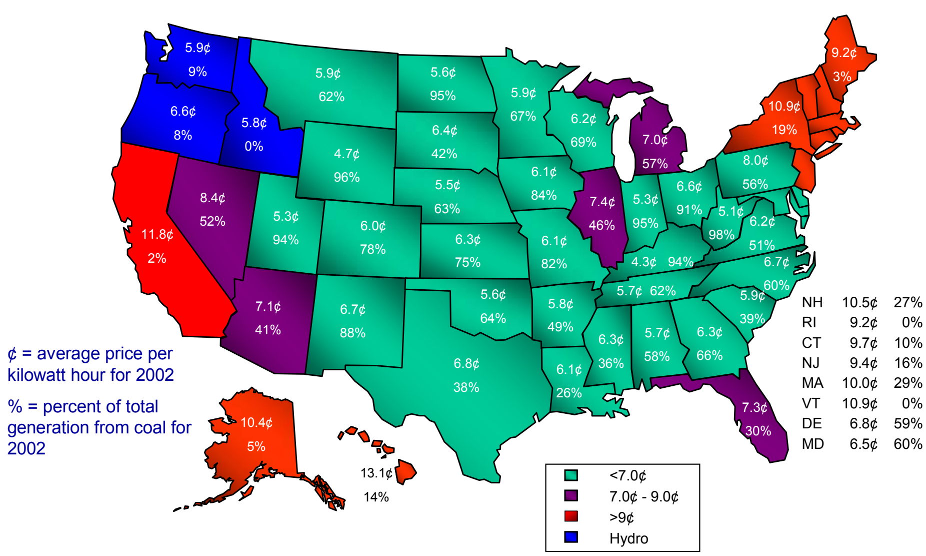
Section 1: Introduction

The nation's energy sector is facing a challenge: increasing stress is being placed on the production, delivery and consumption of energy, especially electricity. Throughout the 1980s and 1990s, American citizens were provided with, and came to expect, secure, reliable, affordable, and environmentally sound energy. This fueled dramatic economic growth and improved human health and welfare, even as environment quality steadily improved. It was assumed that energy would continue to be readily available at low prices, due primarily to low-cost electricity generated using inexpensive coal and nuclear fuels, along with relatively inexpensive natural gas and, for the most part, stable world oil supplies.

The past four years have seen dramatic changes to this longstanding reality. The 1990s resulted in reduced energy investments, lack of balanced policymaking, utilization of excess generating reserves from low-cost nuclear plants, depletion of low-cost natural gas supplies, aggressive litigation and regulation toward coal-based electricity generation, increasing reliance on foreign energy sources, over-reliance in scarce domestic natural gas resources, and under-investment in new coal-based generation and the nation’s transmission system.

The policy and investment neglect has in turn brought about rolling energy shocks marked by sharp natural gas shortages and price increases, high fuel oil, heating oil and gasoline prices, electricity blackouts in the northeast and California, and strained energy infrastructure. There is every indication that these energy shocks will continue and intensify. Since 1990, for instance, reserves of inexpensive coal and nuclear electricity generation capacity have been cut in half. Lacking investment in new coal-based generation, the nation is most likely to rely upon scarce natural gas and other expensive fuels for generating electricity. Statistics show that states that choose coal for generation are rewarded by low-cost electricity. In the United States, the 10 states that use the highest percentage of coal enjoy electricity rates that are 40% lower than the 10 states that use the largest percentage of other fuels. [See Figure 1.1.]

Figure 1.1
Low-Cost Electricity Comes From Coal



The momentum of flawed energy policymaking and underinvestment poses enormous threats to the U.S. economy and its citizens. High energy prices amount to a regressive tax, most severely affecting those least able to gain a voice and most likely to be hurt if proper policies aren't enacted. Consider that 60% of American households earn less than $32,000 per year. They average $400 per month in discretionary income that can quickly be consumed by rising energy costs from natural gas (which, during the winter of 2003, more than doubled from the prior year). During the last U.S. energy crisis, middle-class Americans faced average energy costs equaling 4.6% of their incomes while low-income Americans were forced to pay 19.5% of their income on energy.

The result of relying more heavily on natural gas to cover the growth in electricity demand has negatively impacted the nation's manufacturing sector. In June 2000, the rising cost of natural gas marked the beginning of a negative trend in the number of U.S.-based manufacturing jobs. Between July 2000 and February 2004, the number of domestic factory jobs decreased by over 2.8 million. Most of these jobs have been "outsourced" to other nations with lower energy costs.

American citizens need low-cost energy, and coal provides energy with low and stable costs.

Against this backdrop of rolling U.S. energy shocks related to natural gas, gasoline and oil, increased use of vast U.S. coal resources represents the single most effective step that the United States can take to ensure domestic energy security, low-cost energy, reliability and sustained economic growth.
In order to face this challenge and be responsive to the needs of our citizens, any future energy plan will need to balance production and consumption – both of which are tied to economic and population growth – in an environmentally acceptable way. Supply and demand need to be viewed in a time frame that looks beyond today in order to shape our research and regulatory agendas.

Economic development will require enormous investments in all aspects of energy infrastructure and in all phases of the energy sector; from production to generation, storage to transmission, and distribution to end use efficiency. Any expansion of power supplies must recognize that no single energy source can meet our growing energy needs. Economic security will require a focus on the development of reliable power plants which can serve the growing demand for electricity at stable prices - <u>with adequate domestic fuel sources.</u>

The United States has the largest coal reserve in the world, and America has more coal than any nation has of any single energy resource. Coal makes up 85% of our nation's fossil fuel reserves and fuels over half of our nation's electricity generation. At current consumption rates, these coal reserves make up a 250-year supply of domestically available fuel, which is far greater than our nation's reserves of natural gas and oil combined. Additionally, many of our natural gas and oil reserves are located in areas where drilling is restricted or in areas where most of the low-cost reserves have been substantially depleted. It has been suggested by many economists that liquefied natural gas (LNG) can and must be imported to stabilize natural gas prices. The import of LNG is clearly contrary to our nation's stated goal of energy independence and security. The United States should <u>encourage the utilization of domestic coal to help reduce our future reliance on foreign supplies of fuel</u>.

The United States has the largest coal reserves in the world, and America has more coal than any nation has of any single energy resource. Coal makes up 85% of our nation's fossil fuel reserves and fuels over half of our nation's electricity generation.

Figure 1.2
U.S. Fuel Resources

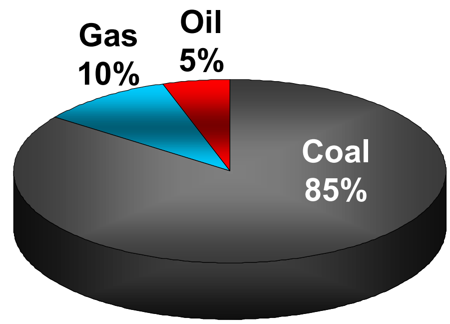
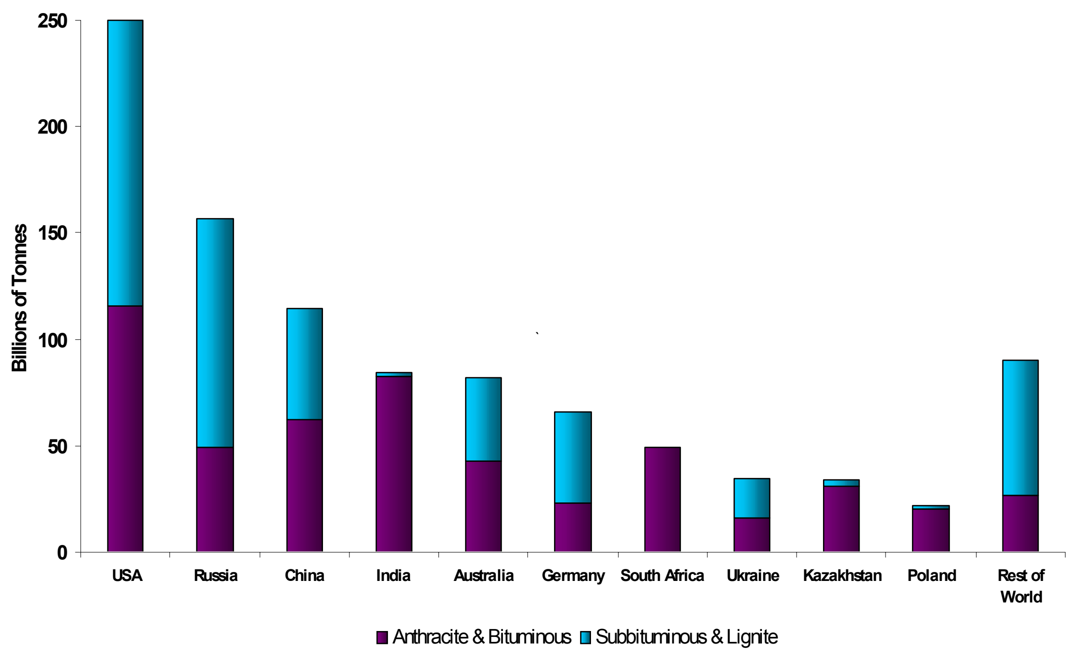
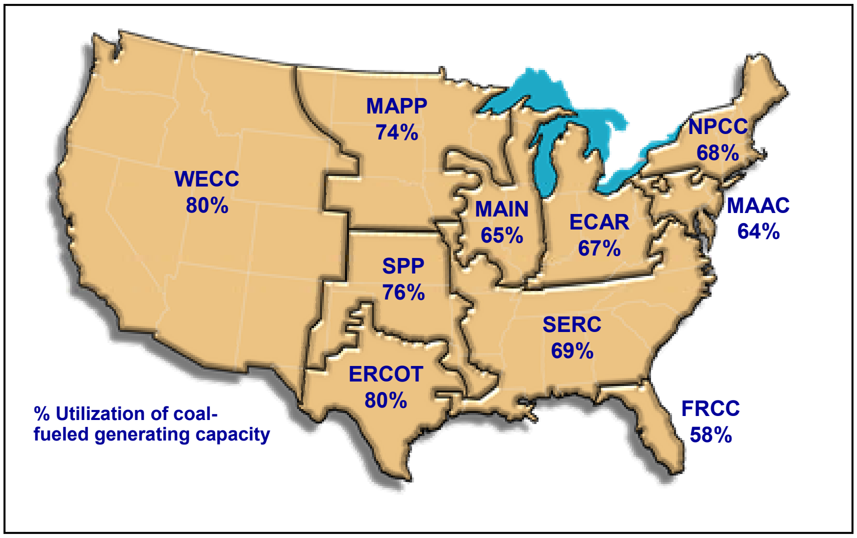


Figure 1.3
World Coal Reserves



From 1980 to 2000, our nation's economy greatly benefited from the development of large coal-based power plants. In 1990, the average capacity utilization factor of a coal plant was 59%; by 2000, with increased demands for low-cost electricity, this factor had grown to 70%. Similarly, nuclear power plant capacity factors have increased from 66% in 1990 to 90% in 2000. The existing nuclear fleet has effectively reached its limit, and the existing coal fleet will soon reach its effective limit of 80-85% utilization. When this occurs, the nation will be short of low-cost, baseload electric generating capacity.

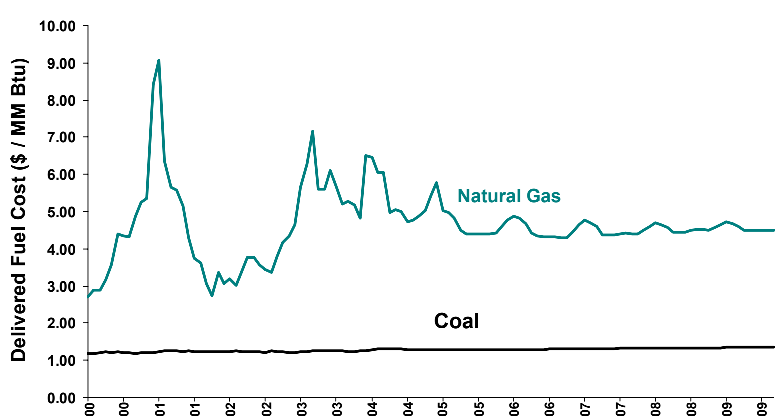
Figure 1.4
Coal Capacity Utilization by Region
Sources: Platts RDI/CoalDat, U.S. Department of Energy



Since very little new baseload capacity had been built in the 1990s, some areas of the country began to experience electric generation capacity shortfalls. This immediate need, combined with easy credit from lenders and the false assumption that natural gas prices would remain low for the foreseeable future, led to a massive overbuild of natural gas-fueled power plants. By default, the energy policy of the United States encouraged the building of natural gas-fueled power plants. From 1998 to 2003, over 140 GW of new natural gas-fired generation capacity was completed. Because the price of natural gas is now at record high levels, much of this capacity is significantly underutilized because its cost of producing electricity is significantly higher than coal or nuclear power plants. If no new capacity is built to take advantage of lower-cost fuels, these new

Most of the natural gas-fueled plants that were built in the past decade are in financial distress because of high gas prices.

Figure 1.5
Historical and Forecasted Fuel Prices



Delivered cost of fossil fuel at steam electric utility plants.

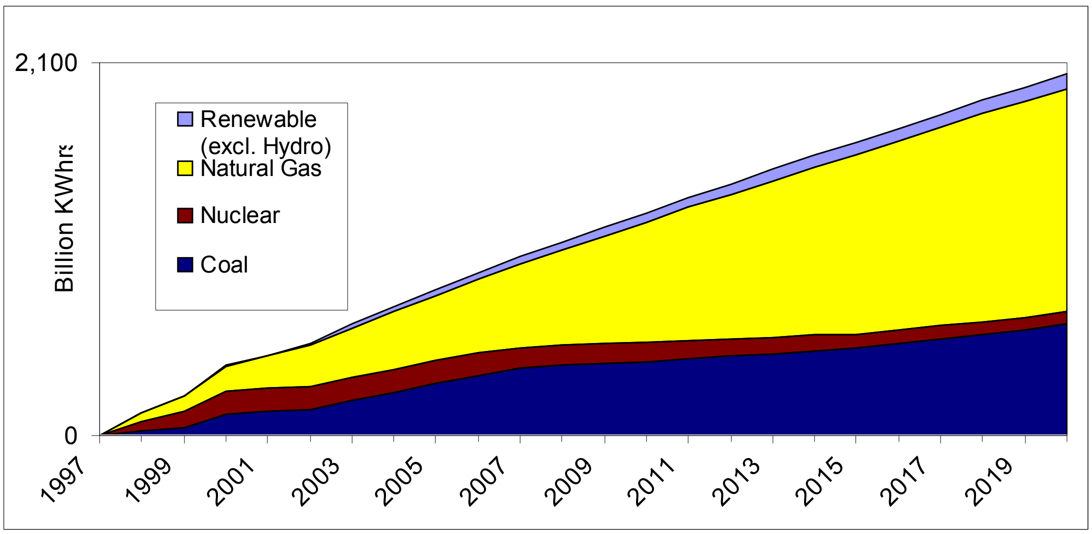
Source*:* RDI Fossil-Fuel Receipts at Steam-Electric Utility Plants through August 2003 to 2009*; U.S. Energy Information Administration, December 2003* Short Term Energy Outlook *and Peabody estimates September – November 2003.* NYMEX Henry Hub, September 2003 – 2009.

gas-fueled plants will eventually run, even in the face of higher gas prices, and at the added expense of those who rely on natural gas for home heating, manufacturing, chemicals, fertilizers and numerous other high-value uses.

According to the EIA, between 1992 and 2002, the demand for natural gas increased by 2.23 billion cubic feet (bcf)/day. Of this increase, 93.6% was due to using natural gas for electricity generation. Since June 2000, when the price of natural gas started its climb, the nation lost over 2.7 million manufacturing jobs. These high paying jobs have fled the country due to the price of natural gas and many will not return. No amount of new import LNG facilities will help to change the cost differential that U.S. industry faces between foreign supplies of natural gas and what can be delivered to their door. What can be relied on is the utilization of U.S. coal for the generation of electricity.

High natural gas prices also hurt other domestic industries and resulted in a loss of jobs.

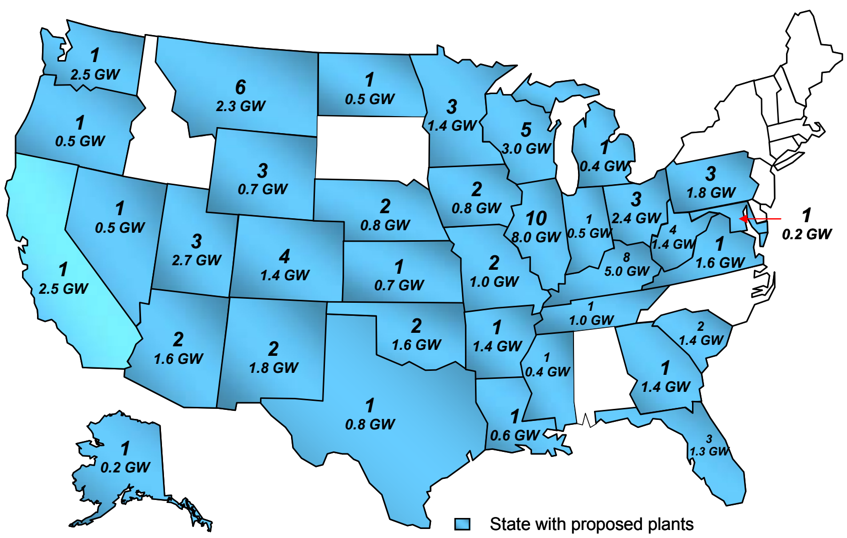
Figure 1.6
Forecasted Growth in Fuel Demand for Electricity Production



Source: EIA Annual Outlook 2004

Building new coal-based plants and increasing the use of coal is the solution to the natural gas shortage and price problem. Using coal for electricity generation frees natural gas for use on higher value applications. A large, new 1,500 MW coal-based plant would displace 0.22 bcf/day of natural gas. If 120 new 1,500 MW coal-based power plants were constructed over the next 30 years, coal-based electricity generation could displace 10 Tcf/year of natural gas demand. The capital cost of this construction would be less than $300 billion (2004$). Figure 1.7 shows a partial representation of the new coal-based power plants proposed in the United States. Announcements of new coal-based plants are occurring at a rapid pace. While it is unlikely that all announced power plants will be built, a reasonable percentage would mitigate the growth in demand for natural gas for electricity generation, and would conserve natural gas for industrial, chemical, and home heating demands where gas provides a premium value.

Figure 1.7
New Coal-based Plants Announced Since 2000

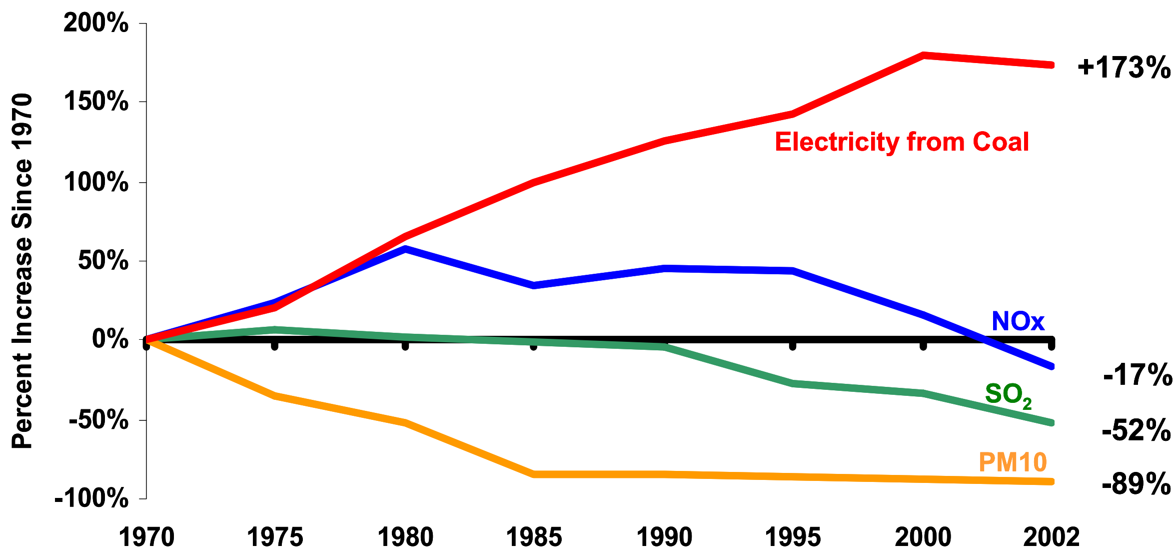


Number of proposed new coal-fueled generating plants and gigawatts of capacity. Source: U.S. Department of Energy, National Energy Technology Laboratory, February 24, 2004.

Energy and environmental issues have become inextricably linked. This linkage is both broad and deep, and involves concerns about air quality, toxic wastes and global climate change. Promoting the economic efficiency and reliability of a competitive energy market, while advancing appropriate environmental policies, is a major challenge. When trying to balance energy needs with societal goals, sound scientific and economic analysis is needed. Cost-benefit and risk analyses are critical tools to be used when reviewing and developing environmental laws and regulations. Industry has made enormous improvements in the environmental performance of coal-based power plants. Emissions from the existing fleet of coal-based power plants are lower today than they were in 1970 even as power produced from coal plants has increased by 173%. With the proposed Interstate Air Quality Rule and the Utility Mercury Rulemaking, the reductions in emissions will accelerate.

Emissions from the existing fleet of coal-based power plants are lower today than they were in 1970 even as power produced from coal-based plants has increased by 173%.

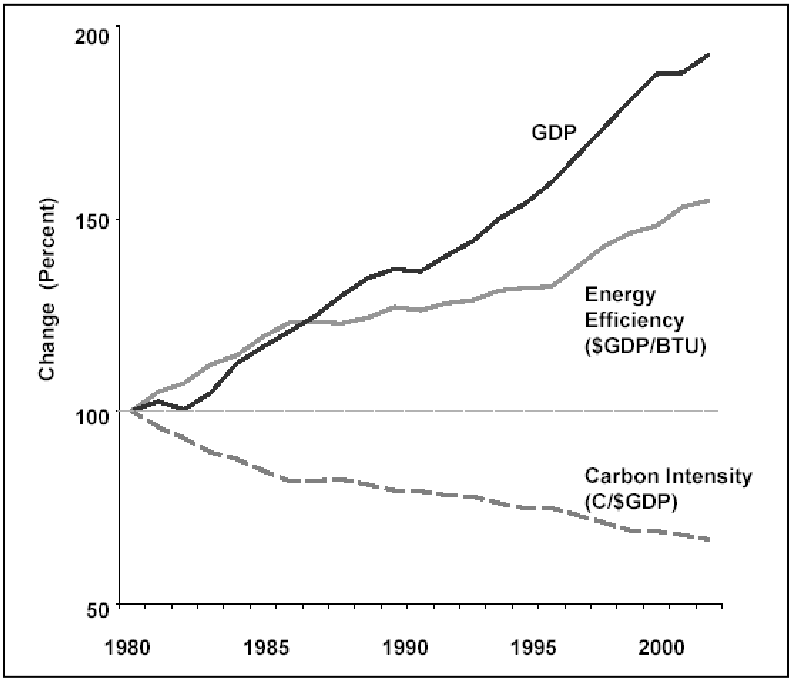
Figure 1.8
Changes in Coal-Based Electricity & Emissions Since 1970



** Estimated*
Source: EPA National Air Pollutant Emission Trends, EIA Annual Energy Review 2002 (October 2003).

One of the long-term, potential concerns with coal use is that it releases more carbon dioxide than other forms of energy production. While it is not the purpose of this report to debate whether or not global climate change is occurring, it is important to note three things about carbon dioxide emissions from coal-based power plants. First, improvements in power generation efficiency make it possible to reduce emissions, including those of carbon dioxide, by using less coal to produce the same amount of electric energy. Second, research and development is ongoing to find ways to economically remove and sequester carbon dioxide emissions from coal-based power plants. The President and the Department of Energy are leading the effort with the proposed FutureGen project. Third, low cost energy, when coupled with end-use technologies that use electricity instead of fossil fuels, allows for more productive use of energy.

Figure 1.9
Low Cost Electricity Leads to Lower Greenhouse Gas Intensity



Markets are not perfect, but they can be a tool for fostering energy security, public health and environmental protection by allocating fiscal responsibility for the public good. Initial market signals, for example, indicated the growing need for peaking capacity requirements (which were relatively less expensive and provided for more expeditious construction compared to larger, base load additions) leading to more acceptable and immediate returns. Now that energy market signals indicate the need for base load units that utilize affordable fuel, the market structure appears to present significant barriers to constructing new generation, especially if it is coal-based.

Investment is required to support our energy growth; R&D, regulatory certainty and appropriate incentives will ensure investment in clean coal technologies.

Cost-effective, flexible and long-term market solutions are needed. These solutions must also recognize that the economy is built on the availability of reasonably priced energy of all forms. Expanded research programs that address science, economics and technology development (and the removal of barriers to the deployment of new technologies) are essential to the nation's economic health. While continuous improvement of environmental controls on power plants is occurring, clean coal technology is commercially available and should be utilized.

While regulatory and tax policies are important tools for attracting the requisite capital investment needed for growth in the energy sector, the main incentive that regulators can provide is certainty. The solution is an integrated approach to regulation that allows an investor to recover the capital invested in a power plant based on existing regulations, with a moratorium on changes to existing regulations that would apply to that facility over an extended period of time. With that, the investment in the plant would not become stranded prematurely. This certainty will allow needed capital stock turnover and provide incentives for new investments.

The goal is to encourage the development and deployment of domestic, reliable, affordable and environmentally sound energy supplies, end use technologies and energy infrastructure. Investment tax credits, loan guarantees and accelerated depreciation (or similar mechanisms) and patent development support should be the primary market tools. Utility commission support and facilitating environmental permitting are the primary regulatory tools. Reliance on a properly structured marketplace for energy decisions regarding pricing, technology deployment, energy efficiency and fuel diversity will provide the needed impetus for economic growth. Investments in energy technology research and development will need to focus on energy sources and uses that can realistically be expected to have a significant impact on economic growth and environmental performance over the next 20 years. The development and deployment of energy infrastructure will need to include technologies that are capable of producing energy at progressively higher efficiency and with lower emission levels for both domestic and global applications. Educational programs recognizing the importance of energy infrastructure and energy sources, their importance to continued energy security, and the link to economic development need to be reemphasized. Comprehensive electric restructuring has to seek long-term improvements to the electric system while energy and environmental regulatory requirements must become predictable.

Public/Private efforts are a desirable way to address the declining investments in the needed research, but this concept does not go far enough. The states and the federal government need to concentrate on allowing innovation to mature. To this end, government needs to underwrite, if not fully finance, private patents (applicable to all the above-mentioned sectors) without taking ownership; and continue this guaranteed investment to the stage of first commercial application. These guarantees, without onerous strings attached, will allow the freedom to pursue ideas that are currently falling by the corporate way-side because they do not add to the immediate bottom line. Financing concepts that can apply to regulated and unregulated states are possible. Major technological changes are needed, however, to accommodate the new open-market approach. This is true for all energy markets, domestic and global. Above all, system reliability must be assured despite vastly more complex operations including huge volumes of hourly and daily transactions and far more participants in the movement of energy from source to users.

Section 2: Technology Choices and Economics

Overview

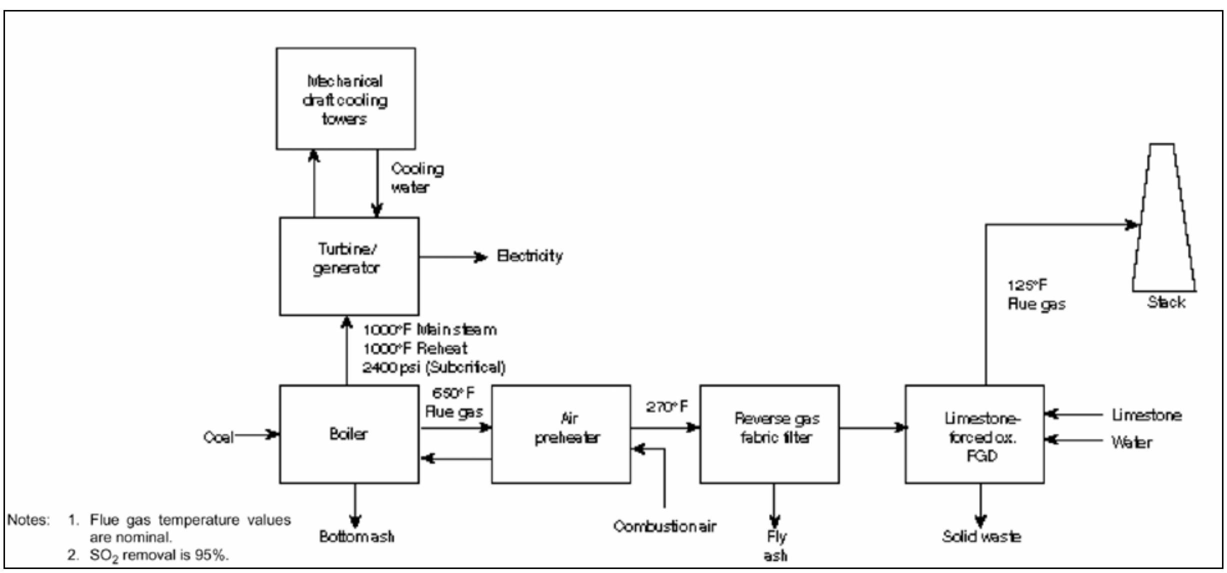
This section of the report provides technical descriptions of the primary types of coal-based technologies being considered for new power plants, focusing on comparisons of their performance, efficiency, and cost. In addition, descriptions of emission control technologies and their impacts on unit cost and performance are discussed. Utilizing this information on performance and cost, the results of an economic case study that compares a range of power generation technologies are provided. This information can be used by plant developers to compare the various technologies, along with their relative capital and O&M costs, environmental performance, heat rate and overall cost of electricity (COE).

Coal-Based Technology Descriptions

Pulverized Coal (PC)

PC plants have continued to develop over the last decade. In the U.S., most have utilized standard, subcritical operating conditions at 2,400 psig/1,000°F superheated steam, with a single reheat to 1,000°F. A typical PC plant is shown in Figure 2.1. Since the early 1980s, there have been significant improvements in materials for boilers and steam turbines and a much better understanding of the cycle water chemistry. These improvements have resulted in an increased number of new plants employing supercritical (SC) steam cycles around the world. SC units typically operate at 3,600 psig, with 1,050-1,100°F main steam and reheat steam temperatures. On the average, these SC units have efficiencies of about 3 percentage points higher than subcritical units, representing an 8% relative improvement in efficiency. Steam temperatures above 1,050°F are often referred to as ultra-supercritical (USC) conditions.

Figure 2.1
PC Block Flow Diagram (Subcritical, Wet Limestone Forced Oxidation FGD)



Over the past 10 years, significant improvements have also been achieved in reducing heat losses in the low pressure end of steam turbines, improving both efficiency and reliability of the overall generating units.

PC plants have been the workhorse of America's coal-based power plant fleet for decades.

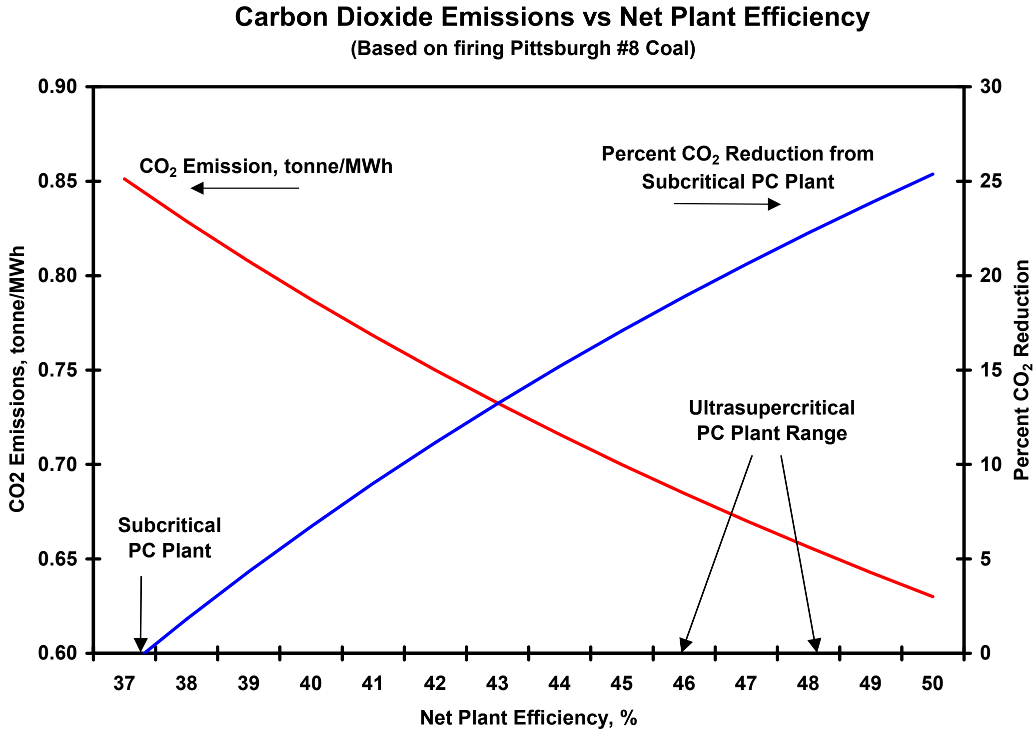
The choice of subcritical cycles for the coal-based power plants that have been built in the U.S. in the last 20 years has been mainly due to relatively low fuel costs. This has eliminated the cost justification for higher capital costs for higher efficiency cycles, such as SC. In international markets, where fuel cost is a higher fraction of the total COE, the higher efficiency cycles offer advantages which can result in favorable COE comparisons and lower emissions compared to subcritical plants. Of the more than 500 SC units in the world, 46% are in the former USSR, 12% are in Europe, and 10% are in Japan. Almost one-third of SC units are in the U.S.; and all of these U.S. units were built prior to 1991. None have been built since, although one has been announced for a plant in the Midwest. There is considerable activity with new SC units in Europe and Asia.

The selection of SC versus a subcritical cycle is still dependent on many other site-specific factors, including fuel cost, emission control requirements, capital cost, load factor, local labor rates and expected reliability and availability. With the extensive favorable experience in Europe and Asia with SC steam cycles during the last decade, their superior environmental performance and the relatively small cost difference between SC and subcritical plants, it is becoming more difficult to justify new subcritical steam plants.

While improvements in boiler and turbine materials and designs have resulted in higher efficiency and availability, the continued addition/retrofit of emission control systems to meet progressively stringent emission standards has had a significant impact on unit performance and cost. Most new PC units utilize flue gas desulfurization (FGD) systems based on wet limestone scrubbing with forced oxidation (LSFO), in order to control SO_2 emissions. With more than 25 years of full-scale commercial implementation of this technology, it has become much more reliable and far less costly. Still, only about one-third of existing coal-based units have FGD systems. Combustion modifications for the reduction of NO_x emissions from existing units have been widely implemented, primarily due to the acid rain provisions of the Clean Air Act Amendments of 1990. Low-NO_x burners developed as part of the Department of Energy's Clean Coal Technology demonstration program in the 1990s have been retrofitted in many units across the country. The retrofit of dozens of selective catalytic reduction (SCR) systems for post-combustion NO_x control resulted from EPA's State Implementation Plan call for NO_x reductions to reduce the interstate transport of NO_x, primarily in the eastern states. The performance of these emission control technologies has continued to improve. However, cost and performance impacts are significant. These impacts are discussed later in this section.

Potential reductions in greenhouse gas emissions, particularly for CO_2, have also gained significant attention. For coal-based technologies, one available option to reduce CO_2 emissions per unit of electricity generated is to increase the unit's efficiency, so that less coal is burned per MWh generated. Figure 2.2 shows the reduction in CO_2 emissions that could be achieved with increases in efficiency. These increases could be accomplished by retiring an older subcritical unit and replacing it with a more efficient boiler (i.e., SC or USC). For example, an advanced USC plant with an efficiency of 46-48% (HHV basis) would emit approximately 18-22% less CO_2 per MWh generated than an equivalent-sized subcritical PC unit. Of course, this reduction would also apply to emissions such as SO_2 and NO_x, since the more efficient plant would use less coal to produce the same energy. It is estimated that if the next 10 GW of coal-based plants were to be built using more efficient SC technology, CO_2 emissions would be about 100 million tons less during the lifetime of those plants, even without installing a system to remove the CO_2 from the exhaust gases.

Figure 2.2 Carbon Dioxide Emissions vs. Net Plant Efficiency



Fluidized-Bed Combustion (FBC)

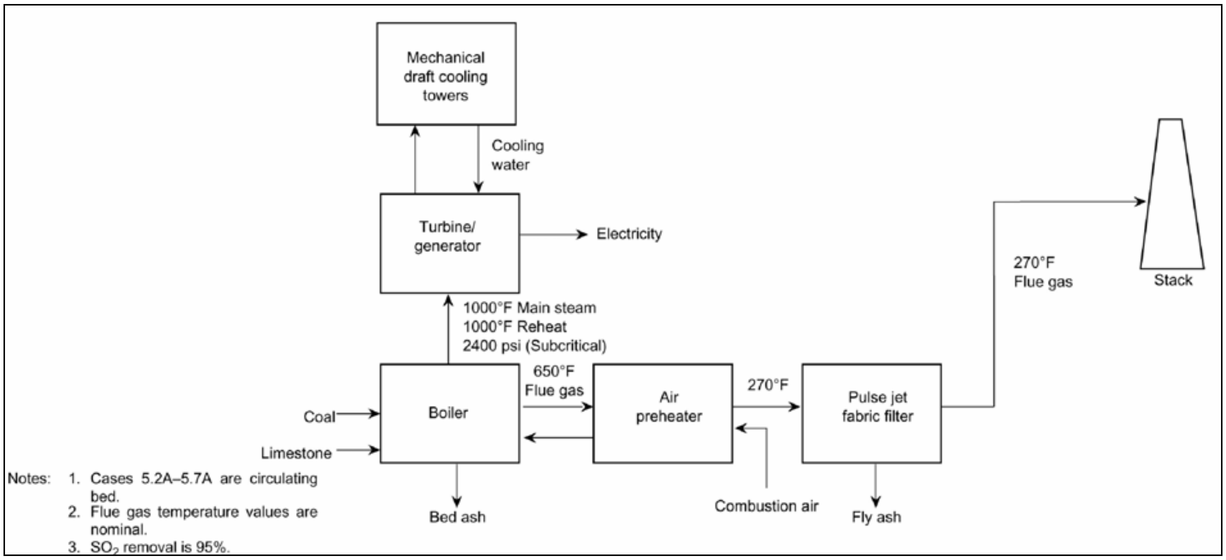
> **FBC technology has benefited greatly from incentives in the 1980s to assist in the commercial-ization of this clean coal technology.**

In FBC units, coal is combusted in a hot bed of sorbent particles that are suspended in motion (fluidized) by combustion air that is blown in from below through a series of nozzles. The fluidized bed of solids provides thermal "inertia" which moderates upsets due to sudden changes in fuel composition. More than 95% of the solids consist of sorbents capable of capturing the SO_2 released during the combustion of coal and inert coal ash. The coal and coal char constitute less than 5% of the bed solids.

A typical FBC plant is shown in Figure 2.3. Like conventional PC units, FBC units operate in a Rankine steam cycle, utilizing steam produced in a boiler to drive a steam turbine generator. FBC boilers operate at lower temperatures than PC boilers, and burn crushed fuel in a fluidized bed rather then pulverized fuel in a PC unit's furnace. The heat rates of FBC plants tend to be slightly higher than PC plants at the same plant size and steam conditions because of higher excess air and higher auxiliary power requirements. In general, FBC boilers burn coals with higher excess air (18-25% instead of 15-20% for PC), which results in higher flue gas heat loss. The higher pressure drop across the furnace requires more fan energy. However, the advantage of using FBC technology is that FBC boilers capitalize on the unique characteristics of fluidization to control the combustion process, minimize NO_x formation, and capture SO_2 in-situ.

In addition, FBC boilers are capable of burning a range of fuels, including bituminous and sub-bituminous coals, coal waste, lignite, petroleum coke, and a variety of waste fuels or "opportunity" fuels like biomass that cannot be accommodated by PC units. In many instances, units are designed to use several fuels, emphasizing one of this technology's major advantages: its inherent fuel flexibility. FBC boilers also can readily handle many fuels that are problematic in PC boilers.

Figure 2.3 Fluidized-Bed Combustion Block Flow Diagram



The most common FBC designs employ a large hot cyclone between the furnace and the convective heat transfer sections to recirculate unreacted sorbent and unburned fuel back to the bed, where the remaining carbon can be burned and more SO_2 captured. These systems are called circulating fluidized-bed combustors (CFB). Due to superior mixing characteristics of CFBs compared to bubbling-bed FBCs, the excess air levels for CFBs are generally lower than for FBCs. Also, the higher sensible heat of the larger solid mass discharged and the higher pressure drop in the forced-draft fan in the FBC plants tend to make the heat rates for FBC inherently higher.

CFB operates at gas velocities high enough to entrain a large portion of the solids (12-30 ft/s), which then is separated from the flue gas and recycled (recirculated) to the lower furnace to achieve good carbon burnout and SO_2 sorbent utilization. Typically, an external hot cyclone is used at the furnace exit as a separation device. CFB recycle ratios usually exceed 40 lbs. of recycled solids per pound of feed solid, and may be much higher depending on the cyclone efficiency.

Because of the high recycle rate (high residence time) of unutilized sorbent and unburned carbon, CFB provides better SO_2 capture and better carbon burnout than bubbling bed (FBC) units. CFB also facilitates more effective air staging for improved NO_x control and is less prone to upsets due to fuel quality variation. Another important advantage of CFBs is that they require significantly fewer fuel and sorbent feed points compared to bubbling FBCs. This provides more simplified designs, better operational characteristics, and easier scale up to larger size units. Consequently, CFB is the predominant type of FBC boiler installed worldwide in unit sizes above 200,000 lbs. per hour of steam. Currently, the largest CFB unit in operation is 320 MW, but designs for units up to 600 MW have been developed by three of the major CFB suppliers. Some of these designs are based on SC steam conditions.

In-bed boiler tubes cannot be used in the CFB furnace because of severe tube erosion. However, an optional external bubbling fluidized bed can be employed as an external heat exchanger (EHE). In this unit, boiler tubes are immersed in a bed of the hot recirculating solids from the cyclone that are lightly fluidized by low-velocity secondary air. The cooler solids leaving the EHE are then recycled to the lower furnace. An EHE can take up a large fraction of the total heat duty in a large CFB unit, and therefore provides a flexible alternative to the need for additional in-furnace heat transfer surface in units larger than 40 MW. An EHE is also advantageous in conserving the furnace height in large CFB units and in optimizing reduced-load operation.

For SO_2 capture, limestone is fed into the fluidized bed in addition to the coal. The limestone is converted to free lime, a portion of which reacts with the SO_2 to form calcium sulfate. At steady-state operation, the bed consists of unburned fuel, limestone, free lime, calcium sulfate and ash. Because of the well-mixed nature of the bed and the relatively long residence time of the fuel particles (via high recycle rates in the CFB), efficient combustion can be maintained at temperatures as low as 1,550-1,650°F. This combustion temperature limits the formation of thermal NO_x and is the optimum temperature range for in-situ capture of SO_2 by the free lime. This temperature also prevents or reduces the slagging of coal ash on heat transfer surfaces.

In an FBC unit, SO_2 capture is a function of the limestone reactivity and Calcium-to-Sulfur (Ca/S) molar ratio, increasing in proportion to these parameters. As the sulfur content of the fuel increases, the Ca/S molar ratio required for a given percentage SO_2 reduction decreases because of the increased driving force (partial pressure) for the sorption process. For high-sulfur coals (> 2% S), Ca/S molar ratios of 2–2.5 are required to achieve 90% sulfur removal. For low-sulfur coals (< 1%), Ca/S molar ratios as high as 3–6 are required to achieve the same 90% sulfur removal. Recent CFB boiler designs include dry FGD systems to remove additional SO_2 at the back end and increase overall SO_2 capture to over 98%. Due to the high molar ratios of limestone required to capture and remove the SO_2, reagent and disposal costs are 50–100% higher than for PC plants with FGD systems using typical bituminous coals.

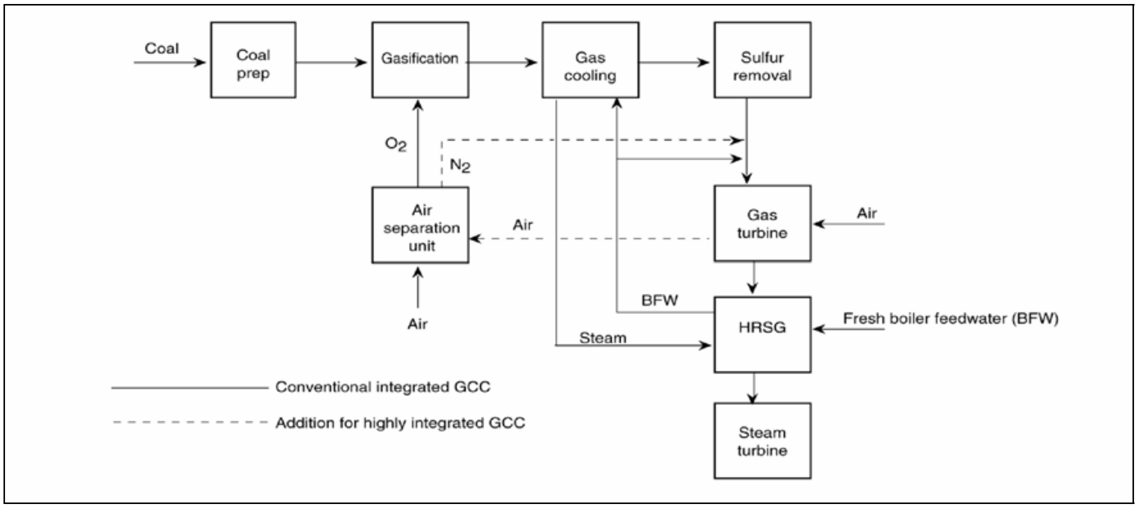
The environmental performance of FBC compared to PC boilers is enhanced by the inherently lower NO_x production due to the relatively low combustion temperatures of the FBC process. Staging the combustion air and decreasing the overall excess air level also reduces NO_x production. Emissions are typically in the range of 0.05–0.20 lb/MBtu without post-combustion NO_x controls, compared to 0.20–0.40 lb/MBtu for new PC boilers with the latest low-NO_x burners and over-fire air. The use of relatively inexpensive selective non-catalytic reduction (SNCR) systems with FBC can reduce the flue gas NO_x level an additional 50-90%, depending on ammonia slip and detached plume considerations. With a PC boiler, the more expensive SCR system would probably be required to achieve the same flue gas NO_x levels as FBC with SNCR.

However, the low combustion temperature does have some disadvantages. CFB boilers emit higher levels of N_2O, which forms and survives at temperatures below 2,000 °F. N_2O is a greenhouse gas with a Global Warming Potential 296 times that of CO_2. Because of its low concentration in the flue gas (typically in the range of 40-70 ppm at 3%O_2) this N_2O emission corresponds to an equivalent 15% increase in CO_2 emissions. A more detailed discussion of N_2O emissions from FBC has been presented in the May 2003 NCC Report “Coal Related Greenhouse Gas Management Issues”.

Integrated Gasification Combined Cycle (IGCC)

IGCC allows the use of coal in a power plant with the environmental benefits of a natural gas-fueled plant and the thermal performance of a combined cycle. A block flow diagram of a non-integrated IGCC system is shown in Figure 2.4. In its simplest form, coal is gasified with either oxygen or air, and the resulting synthesis gas (or syngas), consisting primarily of hydrogen and carbon monoxide, is cooled, cleaned and fired in a gas turbine. The hot exhaust from the gas turbine passes through a heat recovery steam generator (HRSG) where it produces steam that drives a steam turbine. Power is produced from both the gas and steam turbine-generators. By removing the emission-forming constituents from the syngas under pressure prior to combustion in the power block, an IGCC power plant can meet extremely stringent emission standards.

Figure 2.4
IGCC Block Flow Diagram



There are many variations on this basic IGCC scheme, especially in the degree of integration. It is the general consensus among IGCC plant designers today that the preferred design is one in which the air separation unit (ASU) derives part of its air supply from the gas turbine compressor and part from a separate air compressor. Since prior studies have generally concluded that 25-50% air integration is an optimum range, the case study in this section of the report has been developed on that basis.

Three major types of gasification systems are used today: moving bed, fluidized bed, and entrained flow. Pressurized gasification is preferred to avoid large auxiliary power losses for compression of the syngas. Most gasification processes currently in use or planned for IGCC applications are oxygen-blown instead of air-blown technology. This results in the production a higher heating value syngas. In addition, since the nitrogen has been removed from the gas stream in an oxygen-blown gasifier, a lower volume of syngas is produced, which results in a reduction in the size of the equipment. High-pressure, oxygen-blown gasification also provides advantages if CO_2 capture is to be considered at a later date.

IGCC plants have the advantage of very low emissions and high efficiency.

Entrained-flow gasifiers that deliberately operate in the higher-temperature slagging regions have been selected for the majority of IGCC project applications. These include the coal/water-slurry-fed processes of General Electric (formerly ChevronTexaco) and ConocoPhillips (formerly Dow/Destec E-Gas), and the dry-coal-fed Shell process. A major advantage of the high-temperature entrained-flow gasifiers is that they avoid tar formation and its related problems. The high reaction rate also allows single gasifiers to be built with large gas outputs sufficient to fuel large commercial gas turbines. Recent studies have shown that a spare gasifier can significantly improve the availability of an IGCC plant.

Most of the large components of an IGCC plant (such as the cryogenic cold box for the ASU, the gasifier, the syngas coolers, the gas turbine and the HRSG sections) can be shop-fabricated and transported to the site. The construction/installation time is estimated to be about the same (three years) as for a comparably-sized PC plant.

IGCC provides several environmental benefits over PC units. Since gasification operates in a low-oxygen environment (unlike PC, which is oxygen-rich for combustion), the sulfur in the fuel converts to hydrogen sulfide (H_2S), instead of SO_2. The H_2S can be more easily captured and removed than SO_2. Removal rates of 99% and higher are common using technologies proven in the petrochemical industry.

Due to its high flame temperature, combustion of the syngas in a gas turbine can result in high NO_x emissions in the exhaust gas unless controlled by other means. IGCC units can be configured to operate at very low NO_x emissions without the need for SCR. Two main techniques are used to lower the flame temperature for NO_x control in IGCC systems. One is to saturate the syngas with steam or hot water and the other is to use nitrogen from the ASU as a diluting agent in the combustor. Application of both methods in an optimized combination has been found to provide a significant reduction in NO_x formation. NO_x emissions typically fall in the 15 ppmv (at 15% O_2) range, just above those from natural gas combined cycle (NGCC) units, and when converted to a 3% O_2 basis, are similar to those from PC boilers.

An advantage of adding the extra mass from the steam, hot water or nitrogen into the gas turbine is that additional power is generated in the gas turbine and steam cycle. The type of gas turbine largely determines the electric output of an IGCC plant. The GE 7FA gas turbines used in the case study presented in this report have a nominal output of 197 MW in an IGCC application.

The basic IGCC concept was first successfully demonstrated at commercial scale at the pioneer Cool Water Project in Southern California from 1984 to 1989. There are currently two commercially sized, coal-based IGCC plants in the U.S. and two in Europe. The two projects in the U.S. were supported initially under the Department of Energy's Clean Coal Technology demonstration program, but are now operating commercially.

The 262 MW Wabash River IGCC repowering project in Indiana started up in October 1995 and uses the E-Gas gasification technology (which was acquired by ConocoPhillips in 2003). The 250 MW Tampa Electric Company Polk Power Station IGCC project in Florida started up in September 1996 and is based on GE (formerly ChevronTexaco) gasification technology. The first of the European IGCC plants was the NUON (formerly SEP/Demkolec) project in Buggenum, the Netherlands, using Shell gasification technology. It began operation in early 1994. The second European project, the ELCOGAS project in Puertollano, Spain, uses the Prenflo (Krupp-Uhde) gasification technology and started coal-based operations in early 1998. In 2002, Shell and Krupp-Uhde announced that henceforth their technologies would be merged and marketed as the Shell gasification technology.

The Wabash River and Polk IGCC plants represent the cleanest coal-based power technologies that exist today, and the current state-of-the-art facilities have even superior performance. A PC plant with emission controls may approach IGCC's performance in one or two areas, but does not match IGCC's lower overall environmental impact including air, water, and solids emissions. A state-of-the-art IGCC with enhanced sulfur removal technology can simultaneously achieve greater than 99.5% sulfur removal, essentially total volatile mercury removal (greater than 90-95% removal), and PM levels of <0.004 lb/MBtu. The state-of-the art IGCC plant will also produce only 40% as many solid byproducts as PC units, and will use almost 40% less water.

Effects of Coal Quality on Coal-Based Power Generation Technologies

Coal characteristics can have a significant impact on the selection of the optimum technology.

Fuel type is an important criterion that must be considered when choosing a given technology. Theoretically, any of the advanced coal technologies can use bituminous, sub-bituminous, or lignite coals. However, the coal characteristics of the different ranks of coals significantly impact the design of the different technologies and have different impacts on capital costs and operating efficiencies. This section discusses the significant differences.

<u>PC Plants</u>

Coal properties affect PC plant heat rates and boiler size. High moisture and high ash contents reduce boiler efficiency. Concern over corrosion in the cold end of the air heater and downstream ductwork (due to condensation of SO_3 as sulfuric acid) sets a minimum value on the permissible boiler outlet temperature when higher sulfur coals are used, and thereby reduces the achievable boiler efficiency. Each 18°F increase in air heater exit temperature reduces heat rate by about 14 Btu/kWh, or approximately 2%. Lower air heater exit temperatures can typically be achieved in plants designed for higher-quality, lower sulfur coals, where SO_3 levels and their resulting dew points are much lower.

Higher ash, lower heating value and higher sulfur coals adversely impact PC plant costs and performance.

Coal ash constituents can have a major impact on boiler design and operation. PC boilers are designed to utilize coals with either low or high ash fusion temperatures. For low ash fusion temperatures, the ash constituents are in molten form (slag) at furnace temperatures ("wet-bottom boilers"). The molten slag must be cooled, usually in a water bath, then crushed and sluiced to disposal or for recovery as a by-product. When ash fusion temperatures are high, the bottom ash exits the bottom of the boiler in solid form ("dry bottom boilers"), where it enters a water bath and is crushed and sluiced to disposal or storage. Over the past 30 years, many boilers designed for high sulfur, low ash fusion coals have been converted to lower sulfur coals to meet Clean Air Act emission reduction requirements for SO_2. Many of these low sulfur coals also have high ash temperatures. In order to utilize these coals in wet bottom boilers, operators have installed fluxing systems, which add a small percentage of materials such as limestone and iron oxide, chemically changing the make-up of the ash enough to lower the ash fusion temperature and allow it to melt at furnace temperatures. Blending coals of various sulfur and ash contents has become commonplace in the industry as a way to optimize boiler performance and environmental compliance.

Many units have been converted from high-sulfur, eastern bituminous coals to low-sulfur, sub-bituminous coals, primarily from the Powder River Basin (PRB) region. Due to changes in moisture and volatile content, power plant operators have had to make significant expenditures in coal unloading, coal handling, fly ash collection and fire protection systems to be able to handle these dusty coals in a safe manner.

<u>CFB Plants</u>

CFB plants have demonstrated the ability to burn high ash, high slagging/fouling fuels that would be problematic in a PC boiler. The cost impact of designing a CFB boiler to burn a sub-bituminous coal or lignite compared to lower-moisture, lower-ash, and lower-alkaline bituminous coal is less for a CFB boiler than for a PC boiler. This is primarily because the PC furnace heat transfer area must be increased in order to reduce furnace exit gas temperature as the ash softening temperature drops and thereby prevents slagging of the convective pass. Sub-bituminous fuels and lignites generally have alkaline ashes with low ash softening temperatures, which require large PC furnaces. On the other hand, CFB furnace size is strictly defined by gas velocity. CFB size would be increased for sub-bituminous and lignite fuels, but only due to the increase in fuel moisture, resulting in a much smaller increase than for a PC furnace.

CFB Plants have more fuel flexibility and are well suited to burn low-rank coals such as lignite.

IGCC Plants

IGCC plants are proven to work very well with bituminous coal. It is important to recognize that different gasification technologies will likely be required for different types of coal such as lignite and sub-bituminous.

IGCC Plants are well suited for bituminous coals.

The entrained-flow gasifiers of GE, Shell and ConocoPhillips all perform better with lower ash, lower moisture bituminous coals. Although these entrained-flow gasifiers can process all ranks of coal, most existing commercial gasifiers tend to show an increase in cost or reduction in performance with low-rank and high-ash coals. Both the Wabash River and Polk Power Station IGCC plants were designed for bituminous coals and most IGCC studies have been based on using bituminous coals.

The relative feed rate is a function of the heating value of the feedstock, although it is exacerbated by the additional auxiliary power consumption due to increased oxygen usage and coal handling, preparation and feeding – all of these lead to higher heat rates. Gasifier efficiency decreases with decreasing coal rank and more of the coal's energy is in the sensible heat from the gasifier. That leads to higher steam production; however, less of the feedstock energy is available to the more efficient Brayton (gas turbine) cycle and the overall IGCC efficiency is reduced. (The higher steam generation is more than offset by the increased auxiliary power consumption with lower rank coals).

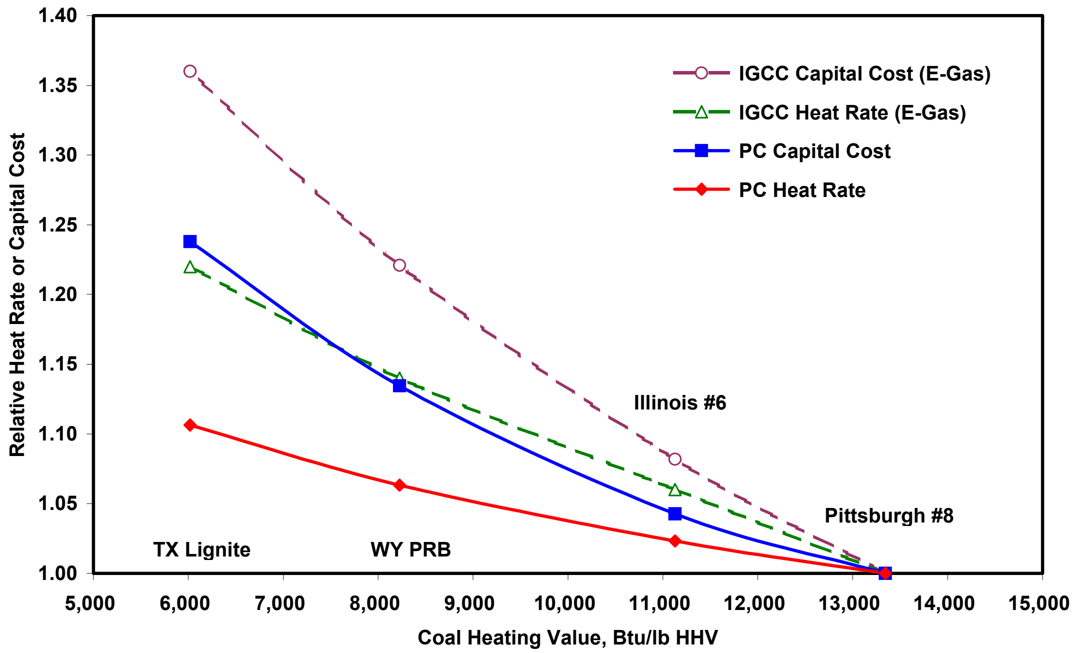
For slurry-fed gasifiers (GE and ConocoPhillips), the energy density slurries of high moisture and/or high ash coal is markedly reduced, which increases the oxygen consumption and reduces the gasification efficiency. Previous studies for E-Gas IGCC plants show a drop in performance and increase in capital costs as fuel quality is decreased from high quality (high carbon) feedstocks such as petroleum coke and Pittsburgh #8 coal to lower quality Illinois #6 and sub-bituminous coals and lignite. As the moisture content of the coal increases, the achievable solids concentration in the slurry becomes lower. Combined with the increased ash content in the lower rank coals, the energy density of the slurry deteriorates markedly. Accordingly, the relative oxygen requirement increases because more oxygen is required to evaporate the moisture.

Research suggests that dry-coal-fed gasifiers (Shell) are more appropriate for low-rank, high-ash coals. While studies show there is an energy penalty (and therefore reduced steam turbine output) for drying the high-moisture coals to the low moisture content necessary for reliable feeding via lock hoppers and pneumatic conveying, less expensive coal-drying techniques are now being developed with Department of Energy funding. In addition, more efficient and effective technologies have shown promising results with low-rank coals, such as the KBR transport gasifier being demonstrated at the Power Systems Development Facility, which receives funding from the Department of Energy, and was recently selected for funding under the DOE's Clean Coal Power Initiative.

Although IGCC is close to being competitive with PC for bituminous coals, gaps widen for the capital costs and COE between slurry-fed IGCC and PC for low rank coals to about $200-300/kW for PRB coal and approximately $400/kW for U.S. lignites. Previous studies by EPRI and others indicate the E-Gas IGCC plants do not appear to compete economically with PC plants when using PRB coals and lignites. Figure 2.5 shows the impact of coal rank, or coal heating value, on the relative heat rates and capital costs of PC plants and E-Gas IGCC plants. This illustrates the challenges of lower rank coals, particularly for slurry-fed gasifiers. This impact would be considerably less for dry-fed gasifiers.

Given the abundance and low cost of U.S. resources of low rank fuels such as Power River Basin sub-bituminous coals and Texas and North Dakota lignites, there is a great need to demonstrate and improve the performance of IGCC with these fuels.

Figure 2.5
Effect of Coal Quality on Heat Rate and Capital Cost



Economics of Power Generation Technologies

Figure 2.6 summarizes the results of an EPRI study which evaluated the performance, capital cost and COE for a range of 500 MW plants using various power generation technologies. The coal technologies for PC and IGCC applications are based on the use of a Pittsburgh #8 bituminous coal. The CFB case is based on the use of Illinois #6 bituminous coal.

While representative capital costs are provided, capital cost estimates can vary widely depending on variable factors like plant location, size, coal properties and owner preference items.

The capital cost estimates shown in the figure represent average costs for each technology, based on EPRI's experience. Capital cost estimates can vary widely depending on such factors as plant location, size, coal properties, and owner preference items. Labor rates can vary by more than 30%, depending on plant location. The resulting total plant costs could vary by as much as 20-25%. The total plant cost (TPC) shown in the table includes engineering and contingency, and is also frequently referred to as the "EPC" cost. Total Capital Requirement (TCR) includes TPC plus other cost items such as interest during construction, start-up costs, working capital and land. Permits and other costs such as owner's engineering, project management, or legal expenses are project- and/or owner-specific and are not included in the TCR. IGCC projects typically include additional cost items in TCR, such as licensing fees, front-end engineering design (FEED) costs, and could also include higher financing costs due to the perception of greater risk. For this EPRI study, the additional costs included in TCR are about 16% of TPC for the PC plants, and nearly 19% is added to the TPC for IGCC plants.

The major components of the 500 MW PC units shown in Figure 2.6 include coal-handling equipment, the boiler island, turbine-generator island, FGD system, fabric filter, bottom ash and fly ash handling systems, and a wet stack with no flue gas reheat. The cost and design data include low-NO_x burners and SCR to reduce NO_x emissions to about 0.1 lb/MBtu for all cases.

The boiler island includes the coal pulverizers, burners, waterwall-lined furnace, superheater, reheater, economizer, soot blowers, regenerative air heater, and axial-flow forced- and induced-draft fans. For the subcritical unit shown in Figure 2.1**,** the steam conditions are 2,400 psig/1,000°F superheated steam, with a single reheat to 1,000°F. For the SC unit, the main steam pressure is 3,600 psig, with 1,100°F main and reheat steam temperatures.

The turbine-generator island includes the main, reheat and extraction steam piping, feedwater heaters, condenser, mechanical draft cooling towers, boiler feed pumps and auxiliary boiler. The steam turbine is a tandem-compound unit, designed for constant pressure operation with partial arc admission. The feedwater heating system uses two parallel trains of seven heaters, including the deaerator; the boiler feed pumps are turbine-driven. The condenser is designed to operate at 2.0 in. Hg back pressure.

An LSFO FGD system is required for medium- to high-sulfur coals (>2%). For this study, the LSFO FGD system utilizes one 100% module and no spare, which has become an industry standard for new units and for many retrofits. The design limestone feed rate is 1.05 moles $CaCO_3$/mole SO_2 removed, achieving 95% SO_2 removal. The flue gas enters the wet stack at about 125°F. The particulate collection system is a reverse-gas fabric filter, located ahead of the FGD system. Two 50%-sized fabric filter modules are connected in parallel.

Many assumptions go into the data used in the table on the next page. The assumptions used will drive the calculated COE, which drives the technology selection. In general, the cost of natural gas will be a primary driver on the economics of NGCC plants. The capital cost and capacity factor will be a primary driver on the economics of a coal plant.

Figure 2.6
Costs for 500 MW Power Plants Using a Range of Technologies

	PC Subcritical	PC Supercritical	CFB	IGCC (E-Gas) With Spare	IGCC (E-Gas) No Spare	NGCC 80% CF	NGCC 40% CF
Total Plant Cost, $/kW	1,230	1,290	1,290	1,350	1.250	440	440
Total Capital Requirement, $/kW	1,430	1,490	1,490	1,610	1,490	475	475
Fixed O&M, $/kW-yr	40.5	41.1	42.2	56.1	52.0	5.1	5.1
Variable O&M, $/MWh	1.7	1.6	4.0	0.9	0.9	2.1	2.1
Avg. Heat Rate, Btu/kWh (HHV)	9,310	8,690	9,800	8,630	8,630	7,200	7,200
Levelized Fuel Cost, $/MBtu (2003$)	1.50	1.50	1.00	1.50	1.50	5.00	5.00
Capital, $/MWh (Levelized)	25.0	26.1	26.1	28.1	26.0	8.4	16.9
O&M, $/MWh (Levelized)	7.5	7.5	10.1	8.9	8.3	2.9	3.6
Fuel, $/MWh (Levelized)	14.0	13.0	9.8	12.9	12.9	36.0	36.0
Levelized Total COE, $/MWh	46.5	46.6	46.0	49.9	47.2	47.3	56.5
1st Year COE, $/MWh	61.4	62.2	61.5	66.7	62.8	49.3	63.5

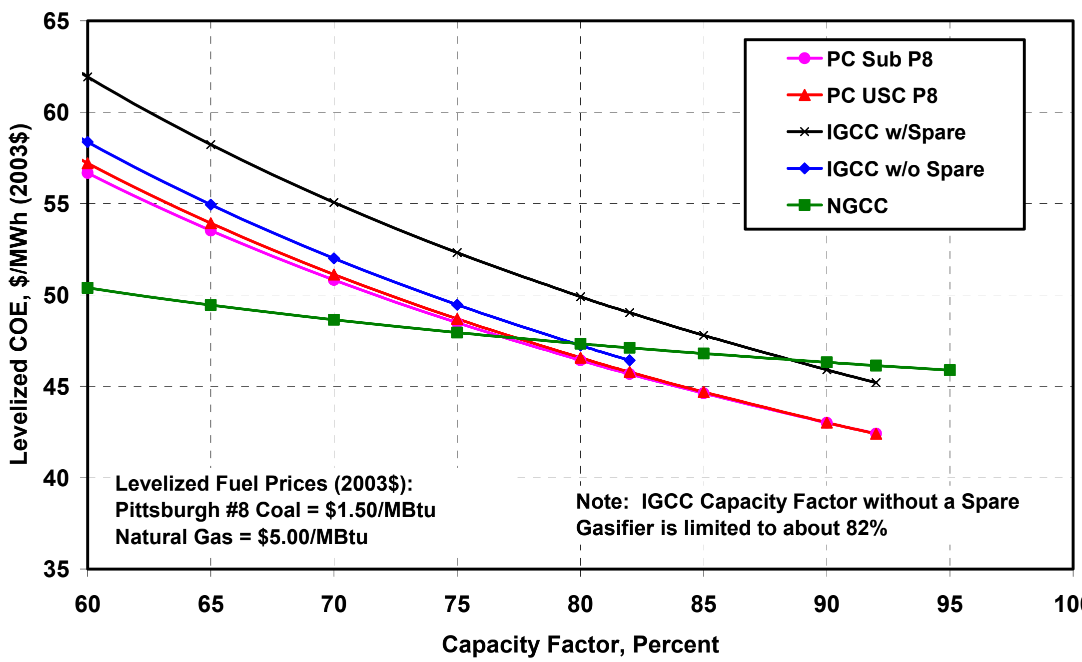
Other assumptions used to derive these results are as follows:

1. *Book life = 20 years*
2. *Commercial Operation Date = 2010*
3. *Total Plant Cost (TPC) includes Engineering and Contingencies*
4. *Total Capital Requirement (TCR) includes Interest During Construction and Owner's Costs (see text for details)*
5. *Assumes EPRI's TAG financial parameters*
6. *All costs expressed in 2003 dollars*

7. *COE is based on Levelized Constant Dollars and is calculated using the EPRI TAG Revenue Requirement Methodology*
8. *PC plants include FGD (95% SO_2 removal) and SCR (80% NO_x removal)*
9. *CFB plant includes 95% SO_2 removal (in-bed) and SNCR for NO_x reduction*
10. *IGCC includes syngas moisturization/nitrogen dilution to reduce NO_x to 15 ppmv*
11. *NGCC includes SCR to reduce NO_x to 3 ppmv*
12. *Capacity factor is 80% except as noted for the NGCC plants*

Plant capacity factor has a significant impact on the COE, especially for capital-intensive coal-based technologies. Figure 2.7 shows the impact of capacity factor on the constant-dollar, levelized COE for the bituminous coal-based technologies. The NGCC case from Figure 2.6 is included for comparison. A spare gasifier for the IGCC case would be necessary to achieve operation at over 85% capacity factor. IGCC plants without a spare gasifier are projected to have equivalent availabilities in the low 80's, whereas inclusion of a spare gasifier is expected to increase the IGCC plant equivalent availability to the low 90's. The coal-based technologies become preferred over NGCC at capacity factors over 78-80%.

Figure 2.7:
Impact of Capacity Factor on Levelized COE



Another factor to consider in the trade-off of coal-based technologies versus NGCC is the fuel plus variable O&M cost, or dispatch cost. As shown in Figure 2.8, about 75% of the total levelized COE for an NGCC unit is due to fuel cost, whereas this drops to only about 30% for the coal-based technologies, as presented in Figure 2.9. This means that even though NGCC and coal may have the same total levelized COE, it is unlikely that the NGCC plant would dispatch before the coal plant, due to its higher fuel cost. Therefore it is unlikely that an NGCC plant would operate at anywhere close to 80% capacity factor. On that basis, coal would be the most cost-effective power generation technology. A recent EPRI report indicates that in 2003 the average capacity factor for NGCC plants was only 29%. With NGCC capacity factors less than

Once the plant is built, coal-based power plants have a significant advantage in economic dispatch because coal is the least expensive fuel.

half of those for coal plants, coal would be the most cost-effective choice for power generation technology.

Figure 2.8
Breakdown of Levelized COE for NGCC Plant

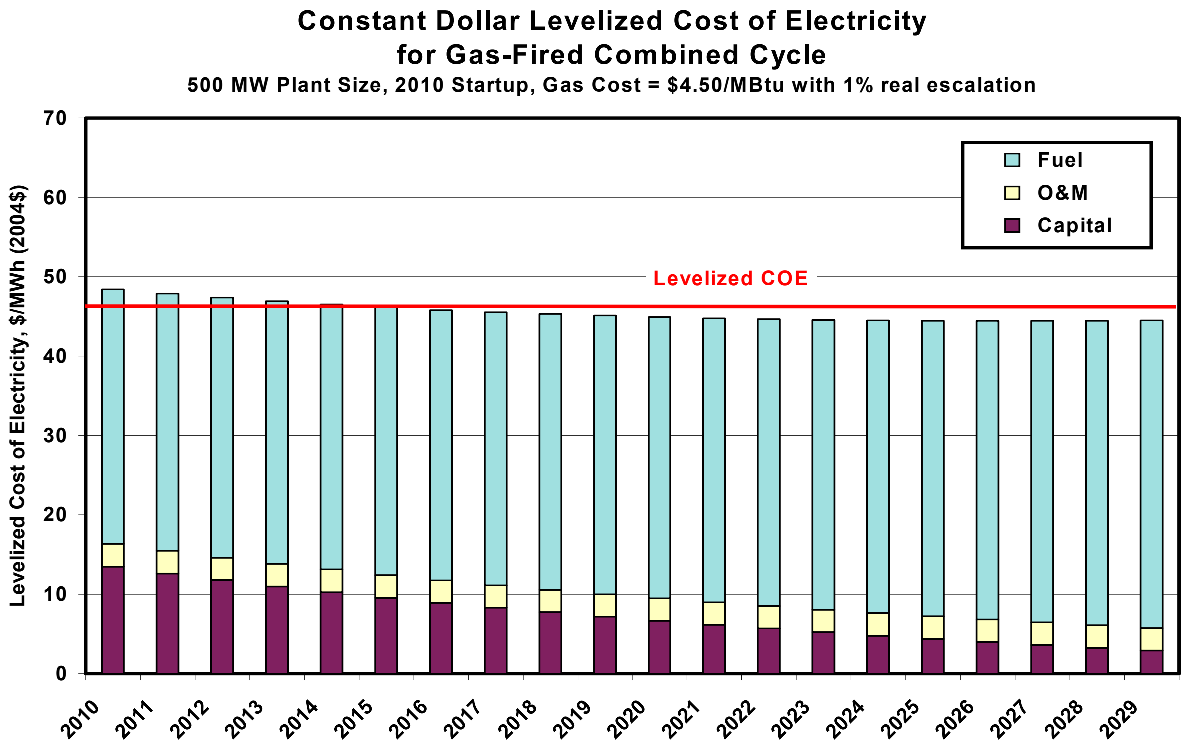
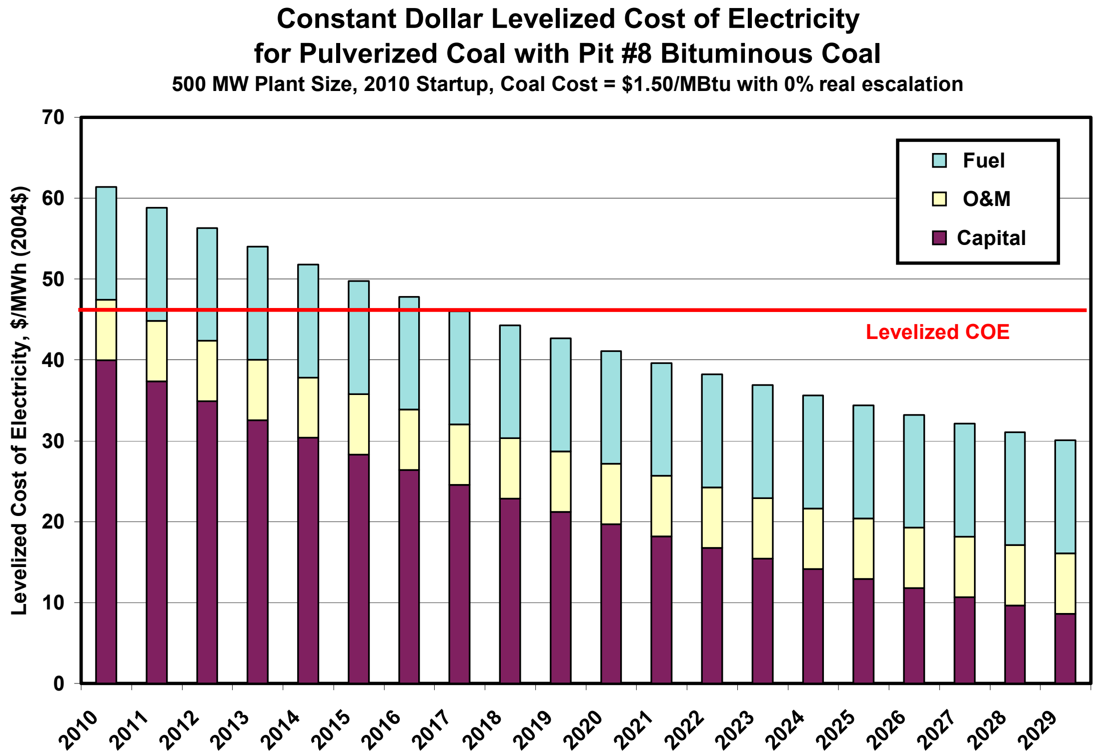
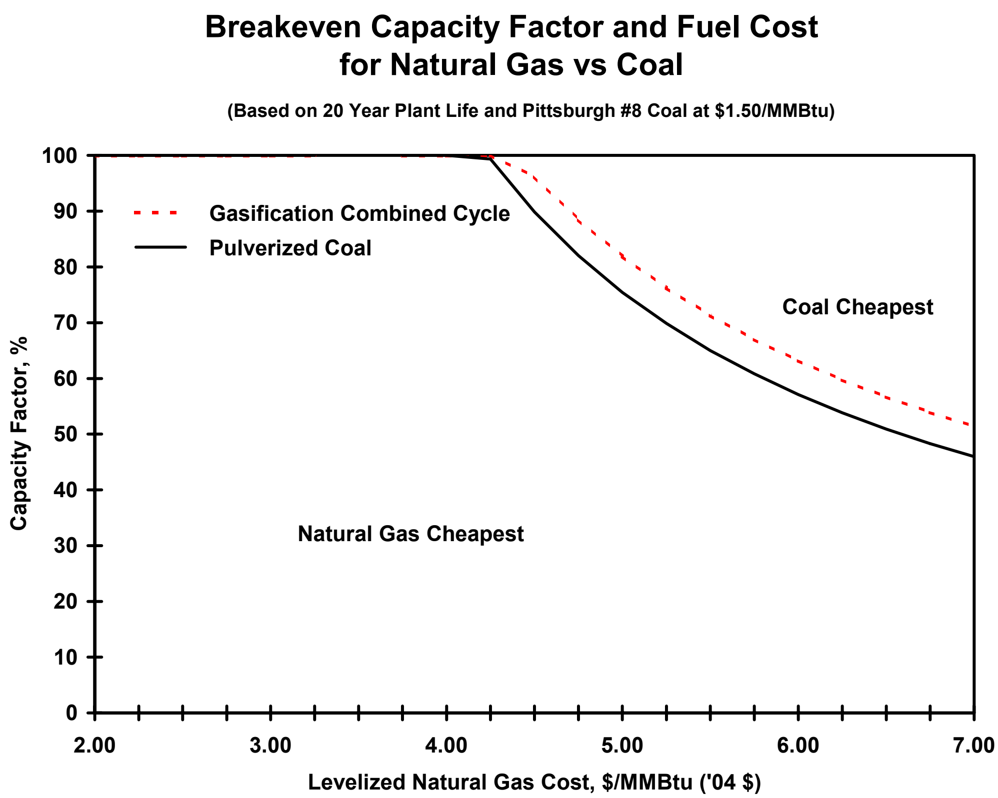


Figure 2.9 Breakdown of Levelized COE for PC Unit



Together, capacity factor and fuel cost can be analyzed to determine which fuel and technology will provide the lowest COE. Figure 2.10 compares PC and IGCC technologies (using Pittsburgh #8 coal at $1.50/MBtu) with NGCC for a range of capacity factors and fuel costs. For high capacity factor (>80%) base load plants, coal-based electricity is cheaper than gas-based electricity when gas prices rise above $4.75/mmBtu.

Figure 2.10



Air Emission Issues and Cost of Mitigation for Pulverized Coal Plants

The Clear Skies Act, the Interstate Air Quality Rule and other environmental control initiatives are being considered for adoption in the near future. If they go into effect, additional emission controls would need to be retrofitted on existing coal-based plants and would be mandatory for new units. This would result in lower overall efficiency and higher O&M costs.

EPRI recently completed a study to estimate the incremental costs for more stringent emission controls for PC plants fired with Eastern bituminous (Pittsburgh #8) and Western sub-bituminous (PRB) coals. In the study, emission controls for SO_2, NO_x and particulate matter (PM) were included. Incremental capital and O&M costs were developed for each 1% change in emission control. In addition, the levelized cost for each additional ton removed and the impact on levelized COE was calculated.

The study was based on a 500 MW subcritical PC plant located at a site in Wisconsin. Prior to retrofit, the plant had no FGD system. NO_x emissions were controlled by "typical" low NO_x burners and over-fire air, while particulates were controlled by an electrostatic precipitator.

SO_2 control technologies included a LSFO FGD system and a lime-based spray dry absorber (SDA) for sub-bituminous coal. For LSFO, the SO_2 removal range was 90-99%. For higher removal rates with LSFO, the scrubber liquid to gas ratio was found to increase nonlinearly with removal percentage. More pumping power was required and gas-side pressure drops were higher. At removal rates above 96%, dibasic acid also had to be added to maintain SO_2 removal.

For SDAs, the SO_2 removal range was 90-97%. For higher removal rates with SDA, the Ca/S molar ratio was found to increase nonlinearly with removal percentage, and larger absorbent and byproduct handling systems were required.

Different NO_x control technologies were used to achieve higher levels of NO_x removal. This differed from the SO_2 control analysis where greater removal levels could be achieved by varying the operating conditions or process parameters. Rich reagent injection (RRI) was used to obtain 25% removal. RRI reduces NO_x formation by injecting amine-based compounds into the fuel-rich region of the furnace. SNCR was used to obtain 30% removal. A combination of RRI plus SNCR resulted in 43% removal. SCR was used to obtain 80-90% removal.

A pulse-jet fabric filter was used to control particulate matter (PM) to levels of 0.03-0.005 gr/acf (0.09-0.015 lb/MBtu). For higher removal levels, the air-to-cloth ratio decreases, the number of compartments increases and the number of bags is increased. For highest removal level, the weight and thickness of bag is also increased.

The results of the study indicated that the levelized COE for bituminous coals increased by $0.57/MWh when the SO_2 removal was increased from the base value of 95% to a high level of 99%. Increasing the NO_x removal level from the base value of 80% to a high level of 90% raised the levelized COE by $0.20/MWh. Finally, the higher level of particulate control increased the levelized COE by $0.13/MWh. Therefore, the total increase in levelized COE in going from the base emission control levels to the highest control levels was only $0.90/MWh.

Even with increased costs for retrofitting emission reduction equipment, coal-based power plants are still expected to remain competitive.

A key conclusion from this case study is that once FGD and SCR systems have been retrofitted, the incremental COE impact to increase SO_2 removal from 95-99% or NO_x removal from 80-90% is quite small, less than $1.00/MWh. Most of the additional cost is for O&M expense and consumables.

Water Issues

Water demand is increasing throughout most sectors of the U.S. economy (agricultural, residential and industrial). This increased demand for water coupled with recent droughts has seriously strained the supply of water. Aquifer levels are dropping, especially in the West. Because of the diminishing supply of water, many recent power plant projects have selected or have been required to install air-cooled condensers, which can cut the water consumption of a combined cycle power plant by about 90%. This trend is nationwide, even in humid regions such as the Southeast. The use of air-cooled condensers has significantly reduced plant efficiency.

Restrictions on water consumption in the future will likely result in a loss in efficiency for new power plants.

Disadvantages of air-cooled condensers include higher capital costs, loss in plant capacity and an increase in heat rate. Air-cooled condensers result in a higher backpressure on the steam turbine, since the temperature of the condensing steam must be above the dry bulb temperature. In a conventional water-cooled condenser, the condensing temperature is keyed to the wet bulb temperature, which is typically

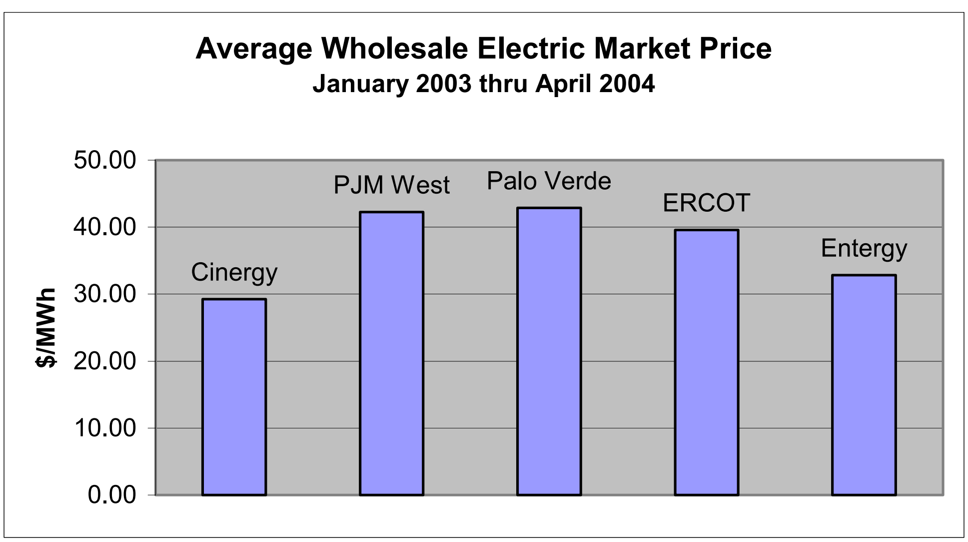
15-20°F below the dry bulb. The performance losses are greatest in the summer, when the need for capacity is greatest (for air conditioning). This loss in performance and capacity is a bigger issue for PC plants since all of the power is produced in the steam turbine, whereas only one-third of the power is produced from the steam turbine for IGCC or NGCC plants. To mitigate these performance losses, hybrid systems have been used on some projects, where a conventional wet condenser operates in parallel with an air-cooled condenser.

Market Price of Electricity from Coal-Based Plants

In a demand-driven competitive marketplace, where the wholesale market purchases electricity from the plant at the incremental cost of production, an investor cannot make a profit on a power plant until the market price of electricity is at or above the COE of that plant shown in the table in Figure 2.6. Usually, older, utility-owned power plants have paid off most or all of the debt and can be dispatched to the electric grid at a cost that is only slightly above the fuel and O&M costs of operating the plant. However, older coal-based power plants are also operationally less flexible and run optimally as base load plants. Given that the daily load is subject to peaks and valleys, the incremental market price is driven by the next most dispatched unit. In most regions, this is a gas-fired plant. In comparison to an older coal-based power plant, a new gas-fired plant has more flexible operating characteristics allowing it to respond more readily to "spikes" in load. However, a gas-fired plant has a higher fuel cost than a coal-based power plant. All things being equal, it is the relative mix of fuel types, heat rates and generation technologies that drive regional market prices, with coal and nuclear plants serving the base load, and natural gas prices driving the market on the margin.

Figure 2.11 provides representative average market clearing prices for various regions in the U.S. The graph shows that the average market price is significantly lower in regions where coal is the dominant source of electricity (i.e., Cinergy and Entergy) compared to regions where natural gas is the dominant fuel for electricity (PMJ, ERCOT and Palo Verde). This reinforces the benefit of lower electricity prices to the consumer where there is abundant, inexpensive coal.

Figure 2.11



Comparing the values in Figure 2.11 to the values in Figures 2.8 and 2.9 reveals the market risk of installing new capacity. Figure 2.8 shows that the levelized COE for a NGCC plant is approximately $50/MWh. Yet the average market prices shown in the four regions in Figure 2.11 are all well below that level. Therefore, an investor would not be able to recover the investment and cover the fuel and O&M costs in a NGCC plant in that region unless the price level reaches approximately $50/MWh by the time the unit is placed in service. If a coal-based plant were to be developed today, Figure 2.9 shows that the market price of electricity would need to be $62/MWh by the time the plant starts up for the investor to recover the fuel, O&M and capital costs in the first year. The comparison between the cost-recovery projections and the market prices is the key factor in developing a plant in a competitive marketplace.

A new plant will only be built if the investor expects to recover both the capital investment and operating costs.

Before investing in a new facility, the forecasted market prices must be sufficiently high enough to cover the cost of operating a plant while earning a return on the capital investment. In today's world, there are two fundamental views on the driving force behind the long-term forward price curve. One view is that a liquid, tradable energy futures market dictates pricing and the demand for investment in new power plants. Others argue that the future prices of electricity should be based on other fundamentals of supply, demand, fuel prices and infrastructure issues. This type of debate is a reason why there are many different projections of future electricity prices for any given region.

Regardless of the projections that are used to justify building or not building a power plant, once a plant is built, the profitability (or loss) of that plant is determined by the ability of a plant to operate successfully. The operation of a plant is dependent on the reliability of the plant and the capacity factor of the plant. The reliability is determined by the ability of a plant to operate when it is called upon to run (availability). The capacity factor is determined by the availability and the market conditions. In a competitive marketplace, the capacity factor will depend upon the market price of electricity compared to the production cost of operating the plant. In a regulated marketplace, profitability (or loss) of that plant will depend on the willingness of the regulator to include the capital portion (capacity charge) of a plant in the rate base, coupled with the dispatch rate of the plant which is determined by the production cost (fuel cost plus variable O&M cost) compared to other plants. When one considers that the capital placed at risk for a large coal-based power plant is in the order of $1 billion, it becomes obvious that the technology risks and market risks associated with competition from existing plants and other technology options must be given careful consideration.

Once a plant is built, it is dispatched based on its operating cost, regardless of the capital investment.

Conclusion

Over the past 20 years, significant improvements in performance and efficiency have been made to coal-based technologies. The use of supercritical boilers is becoming more commonplace around the world, and the re-introduction of this efficient technology has begun in the U.S. IGCC plants are expected to be competitive with conventional plants. While these improvements in coal-based technologies have occurred, new requirements for ever-stringent emission controls have continued to impact coal-based unit performance, efficiency and COE. Improvements in plant efficiencies continue to be the most cost-effective means to reduce CO_2 emissions from coal-based plants. The industry is meeting the challenge to increase the efficiency and decrease the cost for these emission control technologies, in order to minimize the levelized COE for coal-based generation.

There are many technical and economic factors that go into the decisions of whether or not to build a new coal-based power plant and which type of coal technology to use. All of these factors are used as inputs to economic models to project the levelized COE and the long-term viability of these investments. As the price of natural gas continues to rise, the economic benefits for coal-based generation will become even greater.

Section 3:
Clean Coal Power Incentives – Existing and Proposed

The purpose of incentives must be to bring the risk-adjusted COE of new technologies to near that of competing alternatives.

In the past several years, there have been a number of clean coal power incentives proposed in federal energy legislation and by a variety of interested groups including the Coal Utilization Research Council (CURC), the National Association of Regulatory Utility Commissioners (NARUC) and Harvard University. The proposed incentives represent a broad spectrum of approaches including grants, interest-free loans, federal loan guarantees, investment tax credits, production tax credits and favorable treatment by public utility commissions. The targeted projects for such incentives also cover a spectrum ranging from demonstration projects to retrofits of existing coal or natural gas-fired plants to deployment of green field commercial power plants. Some of the incentives are strictly targeted at commercializing IGCC projects, while others apply to all advanced clean coal technologies. A summary description of these incentives follows.

This report does not take a position on the relative merit of various incentives.

This report does not take a position on which of the incentives would be most effective. The important issue is that incentives must enable the life-cycle cost of a new advanced coal-based power plant to be economically neutral to the investor, vis-à-vis competing alternative technologies. Once the cost of a new plant is economically neutral, the utility commission is able to justify placing the facility in the utility's rate base in a regulated environment, or the investor is able to finance the plant based on the expectation that the revenue from the operation of the facility will be sufficient to justify the investment in a competitive marketplace. A key outcome of the incentives should be to encourage deployment of multiple new commercial-scale advanced coal-based plants that are based on relatively proven designs.

Clean Coal Power Initiative (CCPI)

The CCPI is intended to be a 10-year, $2 billion federal program to encourage the demonstration of advanced clean coal power technologies. The program is administered by the Department of Energy as a series of five solicitation rounds occurring on two-year intervals. Round 1 has been completed; and Round 2 solicitations/evaluations are now underway. According to proposed energy legislation, at least 60% of the CCPI awards should be granted to IGCC or gasification-related technologies and up to 40% to advanced combustion and other advanced clean coal technologies.

To meet overall program objectives, $200 million should have been appropriated in each of the authorized 10 years. However, less than 72% of the authorized funding has been appropriated to date. (This figure drops to 60% if the 2005 proposed appropriations are included in the list. Proposed CCPI appropriations for 2005 are only $50 million, just 25% of the authorized amount.) Federal R&D funding appropriations for clean coal technologies have also been reduced by 40% or more in the proposed 2005 appropriations bill.

Under the CCPI program, up to 50% of the cost-share can come from the federal government in the form of interest-free loans. It is intended that these loans should be repaid from the earnings of the awarded project (if successful) or from the revenues resulting from additional commercialization of the clean coal technology (such as future licensing revenues).

Federal Loan Guarantees

Various versions of the current proposed omnibus energy bill have included authorizations for a number of federal loan guarantees for clean coal projects. Most of the proposed loan guarantees have been earmarked for specific projects, but some are more generally limited to a specific type of technology and/or fuel source (such as petroleum coke or coal). Such loan guarantees encourage early commercialization of new technologies by reducing the risk to financers, owners and ratepayers of these relatively expensive yet only modestly proven investments.

Federal Tax Credits

Proposed federal tax credits have primarily taken two forms: investment tax credits and production tax credits. In some cases, these incentives have appeared separately and at other times combined. These tax credits appeared in three main areas of proposed energy legislation: clean coal technologies (repowering/retrofitting applications), advanced clean coal technologies (green field applications) and clean air program incentives (deployment of new commercial technologies). Versions of these incentives appear in pending energy legislation H.R. 6 and S. 2095. These bills have not been approved by Congress to date.

Investment tax credits in the range of 10-17.5% have been proposed for commercialization of new advanced clean coal power projects and in the range of 10-15% for clean coal repowering projects. The investment tax credits are applied to a limited total megawatt allocation in the range of 4,000-6,000 MW for new advanced clean coal projects and in the range of 0-4,000 MW for clean coal repowering projects. In the case of the new advanced clean coal projects, the total megawatts are further allocated across a defined range of advanced clean coal technologies and are sub-allocated across defined time periods. In general, 50% or more of the total megawatts have been allocated to IGCC projects, 25% to supercritical PC technologies, 12.5% to pressurized FBC technologies, and 12.5% to other advanced clean coal technologies. Up to 50% of these allocations are to be used for projects commercialized before 2009, and the remaining allocations for projects commercialized between 2009 and 2017.

Projects that qualify for these investment tax credits must meet certain defined environmental and performance qualifications, such as exceeding targeted reductions of SO_2 and NO_x and carbon dioxide emissions and meeting defined heat rate targets. Coal must be used for at least 75% of the feedstock and at least 50% of the project's output must be electric power. Projects are selected under criteria developed by either the Secretary of the Treasury and/or Secretary of Energy, focusing on those projects with the highest efficiency and/or best environmental performance.

Under certain versions of the proposed energy legislation (such as S. 2095), projects that qualify for these investment tax credits could also qualify for **production tax credits** in the range of \$0.0010-\$0.0140 per kWh for up to the first 10 years of operation (adjusted for inflation for years after 2004). The amount of the production tax credit varies according to the efficiency of the selected project and according to the time period of the project commercialization. The highest production tax credits were assigned to projects with the highest overall efficiencies and the earliest commercialization dates.

Repowering or retrofitting existing older PC boilers with clean coal power technologies also qualified for production tax credits under various versions of the proposed energy legislation. These clean coal technology credits were limited to a total allocation of 4,000 MW of such projects, with no more than 300 MW of credits applied to any one project. The proposed production tax credits for such repowering applications were \$0.0034 per kWh for up to the first 10 years of operation (adjusted annually for inflation after 2004).

In addition to the above tax credits, H.R. 6 (as approved in Conference Committee) allowed five-year **depreciation write-offs** for certain IGCC plants.

Clean Air Coal Program

H.R. 6 (as approved in Conference Committee) also included authorization for almost $2 billion in federal funding for years 2006-2012 to encourage deployment of advanced emission control systems and advanced clean coal technologies. The Secretary of Energy would be given considerable discretion as to how to utilize these funds (grants, loans, loan guarantees, etc.) within certain boundaries (no more than 50% federal government cost-share, projects selected by competitive solicitation, priority to projects smaller than 600 MW, projects must meet certain environmental and heat rate requirements).

3-Party Covenant (Harvard University)

The 3-Party Covenant is a financing and regulatory program aimed at reducing financing costs and providing a risk-tolerant investment structure to stimulate initial deployment of five to 10 IGCC power plants during this decade. Because IGCC is a non-traditional technology for power generation and has more perceived risks, incentives must make IGCC more financially attractive than other options to enable market penetration. The 3-Party Covenant approach was developed by a group led by Bill Rosenberg of the Center for Business and Government, Kennedy School of Government, Harvard University.

The 3-Party Covenant is based on a three-way arrangement among a federal agency, a state public utility commission (PUC) and an equity investor to lower IGCC cost-of-capital by reducing the cost of debt, raising the debt/equity ratio and minimizing construction financing costs. The 3-Party Covenant would significantly reduce the cost of capital component as well as the overall COE for new facilities, making new IGCC technology cost-competitive with PC and NGCC power plants.

The three key elements of the 3-Party Covenant are:

1. **Federal Loan Guarantees:** Federal legislation would authorize a federal agency (such as the Department of Energy) to guarantee long-term debt used to finance qualifying IGCC projects. The terms of the federal guarantee would include allowing for an 80/20 debt-to-equity financing structure and would 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. A government loan guarantee administrator would be established and be responsible for ensuring that a proposed IGCC project demonstrate economic feasibility and the ability to meet debt service obligations. The administrator would also set the financing terms and conditions of a federal guarantee for the debt financing, which include equity investor/owner and vendor performance guarantees to provide a measure of protection to the loan.

2. **State PUC Approval Process:** States interested in participating in the program would voluntarily opt-in by adopting utility regulatory provisions for implementation by their state PUCs concerning review, approval and recovery of the project costs, which might require legislative action to create appropriate enabling authority. Specifically, a state PUC (or other utility ratemaking authority in the case of public power), acting under state enabling authority, would agree to assure dedicated revenues to IGCC projects sufficient to cover return of capital, cost-of-capital and operating costs. The state PUC would provide this revenue certainty through adjustments to utility rates in regulated states or through non-bypassable wires charges in unregulated states, by certifying that the plant qualifies for cost recovery and establishing rate mechanisms to provide cost recovery, including cost of capital. The certification by the state PUC would occur up-front when the decision to proceed with the project was being made. Also, state PUC prudence reviews would occur as construction was ongoing, which would reduce construction risks borne by the developer, avoid accrual of construction financing expenses and protect ratepayers. It would be the responsibility of the state PUC to evaluate IGCC investment decisions, including a due-diligence certification process, before costs could be passed

along to ratepayers. After commencement of plant construction and thereafter, the state PUC would conduct ongoing prudence reviews that would protect ratepayers and would be the basis for approving recovery of costs.

3. **Equity Investor:** The equity investor under the 3-Party Covenant would be either an electric utility or an independent power producer that secures a long-term power contract with a utility. The investor would contribute equity for 20% of project costs and negotiate performance guarantees to develop, construct and operate the IGCC plant. A fair equity return would be determined and approved by the state PUC before construction begins. The assured revenue stream provided by state PUC certification and approval enables underwriting of the federally guaranteed loan using a higher debt-equity ratio (80/20) than available under traditional utility financing terms. The federal guarantee provides the purchaser of the long-term debt with an "AAA" credit rating backed by the full faith and credit of the U.S. government.

Implementation of the 3-Party Covenant would require federal legislation authorizing loan guarantees for qualifying IGCC projects. The primary risk to the federal loan guarantees is the regulatory risk that state PUC determinations regarding cost recovery would be modified or overturned at a future date. This regulatory risk, which could be reduced or removed through state legislation or other action, is much lower than the risk associated with merchant financing. Using the 3-Party Covenant would reduce the default risk of such loan guarantees and would allow a larger number of new plants to be covered by a given amount of appropriations. Current proposed federal energy policy legislation provides a structure that could provide these federal loan guarantees.

There are several benefits of using the 3-Party Covenant approach.

- First, the adjustment for cost-of-capital recovery during construction reduces the total required investment, making an IGCC plant only slightly more expensive to build than a conventional PC plant.
- Second, due to the change in capital structure to 80/20 debt-to-equity, the equity required for an IGCC plant decreases to approximately half that required for a traditional plant under regulated utility financing. However, this high degree of leverage may not be suitable for investor owned utilities.
- Finally, the weighted average cost-of-capital in the 3-Party covenant case is reduced by several percentage points, as compared to the traditional regulated scenario. This reduces the effective overall capital costs of an IGCC plant by almost 40%.

The net effect would enable IGCC plants to produce energy at lower cost than either a PC plant or an NGCC plant in a traditional regulated financing scenario, making it the most attractive development option.

NARUC Proposed Incentives

The Department of Energy and NARUC contracted with Global-Change Associates to conduct a broad survey to determine barriers to commercial deployment of IGCC plants. Based on the outcome of that survey, a large number of recommendations were developed and listed in a March 2004 report, *An Analysis of the Institutional Challenges to Commercialization & Deployment of IGCC Technology in the U.S. Electric Industry: Recommended Policy, Regulatory, Executive and Legislative Initiatives*.

The recommendations were organized into six key areas:

1. **Siting and Permitting:** The licensing of IGCC power plants is more complex than for conventional coal- or natural gas-fueled generation facilities. Currently, IGCC plants are subject to multiple federal and state environmental rules, and may be licensed as electric generation units, syngas facilities, and/or co-production plants. The White House Task Force on Energy Project Streamlining could establish a multi-jurisdictional group to develop uniform licensing standards for siting and permitting IGCC plants. The states could develop memoranda of understanding specifying compatible regional standards to address air shed issues associated with IGCC permitting.

2. **Project Capital and Plant Availability:** If capital costs exceed a pre-determined target, there could be a sharing of the overruns between the developer and the federal government to partially protect developers without unduly weakening their incentive to hold down costs. An IGCC Availability Assurance Program, modeled after similar programs the federal government has established in other areas, could address concerns about possible limited availability of IGCC facilities in their early stages of operation. It would provide funding to partially defray the cost of possible extended outages in the first few years after a plant is put into operation.

3. **Co-Production/National Security:** An IGCC facility can produce both electricity and transportation fuels. The value of the plant can be optimized by turning out each product when its price is highest (producing electricity during the day when demand and prices are high, and producing transportation fuels when electricity demand and wholesale electric prices are low). The production of transportation fuels from such a facility would provide significant national security benefits. A study could be initiated to analyze the ability of IGCC power plants to operate on an economic dispatch basis to co-produce transportation fuels as well as electricity.

4. **Strategies for Meeting Environmental Standards:** The deployment of IGCC technology is hindered by uncertainty regarding future regulations, the piecemeal approach of the electric industry and regulators to meeting future environmental standards, and the absence of efficient markets in which the forward value of emissions reductions can be monetized. As a result, the value of emissions reductions cannot be recognized as an offset to the capital costs of IGCC and determinations regarding the choice of technology for new or repowered plants cannot be made on a sound economic basis. Efforts could be made to develop comprehensive plans for meeting existing and anticipated emissions reduction requirements. Appropriate measures could be implemented to monetize the value of future emissions allowances (for NO_x, SO_2, PM and Hg) through creation of forward markets, including accounting standards that allow recognition of these assets by the Securities and Exchange Commission and state PUCs. In addition, a study could be undertaken to address institutional challenges to commercialization and deployment of CO_2 sequestration technologies.

5. **Cost of IGCC Power Plants Relative to the Cost of NGCC Plants:** The NARUC survey indicated that the most significant challenge to the deployment of IGCC plants is their higher capital costs relative to NGCC plants. However, the pricing of electricity from NGCC and IGCC power plants does not adequately reflect several critical considerations including the importance of using natural gas in industrial processes and residential heating, the recent run-up in natural gas prices resulting from increased pressure on supplies, the accelerated depletion of the nation's limited reserves of natural gas, and the need for increased reliance on gas supplies from unstable areas of the world as domestic supplies are used up. New policies should be developed to address this situation. Measures could be developed to facilitate deployment of IGCC plants and reduce undue reliance on NGCC plants, thereby decreasing pressure on limited natural gas supplies and freeing up natural gas for essential uses such as industrial processes and residential heating. Transmission Service Providers (TSPs), Independent System Operators (ISOs) and Regional Transmission Organizations ("RTOs") could be required to establish target portfolio standards for IGCC-produced power. TSPs, ISOs and

RTOs could be required to provide modest credits financed through uplift charges for electricity produced by IGCC power plants in their early stages of operation. A study using the National Energy Modeling System (NEMS) could be undertaken to assess the impact of expanded IGCC deployment on natural gas prices and availability.

6. **Potential Federal and State Actions:** Meeting requirements for reduced emissions of sulfur oxides, nitrogen oxides and mercury by using IGCC to repower conventional coal-fueled generating plants could be less costly than meeting each of the requirements separately via a piecemeal approach. The EPA could initiate negotiations with coal plant owners to develop a comprehensive approach for meeting existing and anticipated emissions reduction requirements based on repowering with IGCC and consider mechanisms for monetizing future reductions of emissions that are likely to be regulated. This could result in long-term settlements and the repowering of plants with IGCC technology.

A federal greenhouse gas (GHG) registry could be created to facilitate voluntary GHG emissions reductions, supplemented by compatible state, regional and global registries. The registries could facilitate bilateral trading and allow entities to bank reduction credits. This could provide an important means of financing IGCC projects, particularly for repowering. Regulators could develop tools to take GHG reductions in registries into account in the regulatory process, such as granting regulatory assets in exchange for GHG credits.

A specialized team of experts could assist in the siting and permitting processes for IGCC plants and in bringing new technological advances into the process. This team could also intervene in siting and permitting proceedings to assure that the benefits of using IGCC are fully considered in technology determinations.

The project finance community has virtually no experience with IGCC projects. A targeted effort to assist the financial community in understanding the issues associated with IGCC deployment could position it as a preferred technology. Such information could also be provided to state regulators and developers.

The Department of Energy could establish a university center for the training and qualification of personnel capable of participating in the design, construction and operation of IGCC power plants. Such a program for training and qualifying personnel is needed to rapidly deploy this technology and realize its benefits.

A business case for the benefits to the U.S. of exporting IGCC technology, equipment and construction services could be developed. The Export-Import Bank, the Department of Treasury or another entity could evaluate the economic implications of exporting IGCC technology, construction services and equipment.

This list of NARUC recommendations is broad and could be prioritized to form a basis for future federal and state actions to increase the adoption of IGCC.

Conclusion

While many financial incentives have been proposed and implemented, their impact on the deployment of new clean-coal technologies has been less than expected. However, financial incentives are required to overcome the risk-adjusted cost differential between conventional existing options and new, more efficient lower-emitting advanced coal-based plants so that these advanced plants can be more expeditiously deployed into the market place. The menu available for such incentives includes, but is not limited to, tax incentives, production incentives, public/private cost sharing, accelerated depreciation, loan guarantees, and federal credit. Meaningful financial incentives enable the life-cycle cost of a new advanced coal-based power plant to be economically neutral to the investor, vis-à-vis alternative conventional technologies. In addition, it is important that state, regional and federal regulators play a significant role in working with utilities and investors to incentivize the construction of advanced and efficient coal-based power plants.

Section 4: Financial Overview of Investing in New Coal-Based Generation

Corporate Financial Overview and Outlook for the Electricity Generation Sector

The outlook for IOUs and for the competitive wholesale energy sector, including independent power producers, diversified energy merchants and energy traders, is stable. This overall outlook is somewhat deceptive, however, as these two segments are in two very different places and, medium- to longer-term, are headed in divergent directions. While the IOUs either maintained creditworthiness or are well on their way to recovery, the merchant or competitive energy sector will need much more time (and consistent favorable developments) to recover.

Some noted analytical firms specializing in U.S. electricity and natural gas focused on the polarization between the stable outlook for those utilities which did not have significant merchant energy activities, including public power entities, and the negative outlook for those companies that were major participants in competitive power and gas markets, or whose affiliates/parents had large exposures. They predicted that the credit gulf between "untainted" regulated utilities versus their unregulated wholesale peers would widen in 2003. The ensuing year has borne out that prediction. At the same time, they anticipated fewer downgrades for 2003, a prediction which has also been validated with 53 downgrades in 2003, less than half of the figure for 2002, and offset by 25 upgrades against seven in 2002.

Structural differences between IOUs and other energy companies must be recognized.

The rating outlook for 2004 remains stable for regulated distribution and transmission utilities and integrated (generation, distribution and transmission) utilities. Moreover, the 2004 rating outlook is also stable (or, more accurately, neutral) for wholesale energy market participants, albeit at considerably lower credit ratings. The median rating for the diversified energy sector remains single-B, implying a one-in-three chance of default over five years. Thus while the credit ratings may be stable at this level, they are stable at an elevated likelihood of default for these issuers. By way of contrast, public power systems (municipals and electric cooperatives) remain least affected by electric industry restructuring, with debt ratings holding in the A category.

Looking out over the next five years, wholesale energy market participants face adverse political, regulatory and competitive factors that result in a potentially more negative medium-term outlook for that sector. Despite an adverse external environment, some individual companies in the wholesale sector will improve their financial condition, reduce outstanding debt and increase their capital market access. Others are likely to face a renewed liquidity crunch in 2007-2009 when the companies once again face a heavy schedule of debt maturities.

Near-Term Outlook

The near-term rating outlook for the regulated electric utility sector is stable. In fact, in many regards, the industry risk profile is the lowest it has been since electric industry restructuring began in the mid-1990s. The stability results from a number of factors, including lower-risk business plans, a more settled state regulatory environment, on-going benefits from cost reduction measures, a low interest rate environment, and less pressure from external sources (including counterparties and affiliates). The stable outlook also assumes that capital and banking markets will remain reasonably open.

The outlook for regulated utilities is stable in the short term.

The rallying cry of "back to basics" evident in many utilities' revised strategies contributes to this stable outlook. Core investment, including a swing back toward utility self-build or acquisition of power production assets and additional investment in reliability and environmental controls, is generally supported within the near- and long-term stable outlooks. This trend is a reaction by utilities and state regulators not just to the high-profile disappointments of recent non-core diversification, but also against weak credit fundamentals of independent power producers and fears of revocation of physical power supply contracts by bankrupt generators. Other incentives for utilities to buy or build new power supply, rather than contracting with wholesale suppliers, are utilities' lower cost of capital and a renewed willingness to invest in traditional utility property as a source of future earnings growth. The associated increase in capital expenditures is expected to be moderate in 2004 as managements formulate plans to address reliability and supply issues, and to increase during 2005 and thereafter as plans are implemented.

While in past cycles increased capital investment resulted in deteriorating credit quality due to regulatory lag and prudence disallowances, leading analysts to anticipate less credit stress this time around. Prudent managements are not likely to proceed with a major increase in utility capital spending without implicit or explicit regulatory support. While full recovery of new investments is still not assured, regulatory support lessens the likelihood of severe disallowances. Many states already have mechanisms to accelerate the approval and recovery of new investments. In Indiana and Missouri for example, regulators have approved the transfer of generating capacity from an unregulated subsidiary to a regulated affiliate, while Nevada and Wisconsin have approved resource plans that include new coal-based and gas-fired generation facilities.

Regulators' reluctance to have a repeat of the August 2003 blackout or the 2001 California energy debacle also bodes well for regulatory support of new infrastructure investments. State regulators are loathe to repeat the mistakes of California (unhedged supply obligation) and have shown a greater willingness to balance the political goal of rate stability with maintaining utility credit quality and a reliable energy supply. New Jersey, Connecticut and Maryland have implemented or are in the process of implementing an auction process to serve the provider of last resort obligations and eliminate commodity price exposure. While the auctions also heighten counterparty credit exposure, they increasingly contain credit terms and collateral requirements that provide some protection to utility purchasers from counter party defaults. State regulators' virtual abandonment of restructuring initiatives also contributes to a more stable regulatory environment.

Enhanced liquidity as a result of improved capital market access and lower utility bond spreads also support a stable outlook. Unlike other sectors within the global power universe, regulated utilities have an incentive to maintain a reasonable capital structure and generally have maintained market access even in the most turbulent times.

The currently low interest rate environment also benefits the near-term outlook. Typically, low interest rates are favorable for this capital intensive industry. However, the currently low interest rate environment is a matter of some concern for companies involved in rate reviews, as correspondingly lower allowed returns on equity will likely result in reduced revenues, cash flow and earnings, all else being equal.

On the qualitative side, concern about counterparty credit risk and affiliate pressure has been substantially reduced. Over the past two years, pressure on affiliates (usually those that have been involved in merchant plant development or non-core businesses) has accounted for the majority of rating downgrades in this sector. Going forward, the impact of rating linkage is likely to be more symmetrical given the lowering of utility parent ratings and affiliate merchant generators as well as the potential for utility procurement plans to prop up the ratings of affiliates.

Commodity price exposure will continue to be an important determinant of business risk and consequently credit quality. The risk is largely eliminated for pure electric distribution companies with no supply obligation and substantially reduced for those companies with automatic fuel pass through mechanisms, although regulatory lag can still pressure liquidity. Owning sufficient generation to meet customer load also lessens commodity exposure, but without a fuel and/or purchased power pass-through mechanism, a utility is vulnerable in the case of plant outages, which can be particularly onerous for nuclear plant operators as recently demonstrated by the impact of Davis-Besse nuclear outage on the cash flow and ratings of FirstEnergy Corp. Examples of utilities with fixed tariffs and no opportunity to recover variable supply costs are all electric utilities in Missouri (including Ameren and Aquila) and Michigan electric utilities Consumers Energy and Detroit Edison (subject to fixed rates phasing out by Jan. 1, 2006). Commodity risk is greatest for distribution companies with fixed rates and an unhedged supply obligation, as was the case for California electric utilities in 2000-01, with disastrous results.

Five Years Out

Environmental regulations and PUCHA regulation are significant issues that could affect regulated utilities in the longer term.

Stricter environmental compliance requirements and the elimination of the Public Utility Holding Company Act (PUHCA) are two significant issues that could affect regulated utilities in the longer term. In the case of the environmental issues, the impact will depend on the regulatory treatment of the potentially higher costs, which could include replacement of inefficient, older generating units. Potential losers are large coal-based utilities, while beneficiaries would be merchant and other competitive generators that rely on environmentally clean fuels such as nuclear power. In addition, to the extent surplus capacity is reduced, all merchant generators benefit.

If PUHCA is eventually repealed, mergers and acquisitions and event risk would increase. The elimination of PUHCA restrictions would likely attract non-traditional buyers to the utility sector. Even without PUHCA repeal (which does not restrict single-state utility acquisitions), there have been signs of increased merger and acquisition activity as 2003 draws to a close. After the attraction of the gas sector last year for AIG MezzVest and Macquarie Infrastructure Group, this year Texas Pacific Group, a private equity management firm, has formed a new, Oregon-based company to attempt to purchase Portland General Electric Company from Enron and Kohlberg Kravis Roberts and JP Morgan Partners have combined to acquire Tucson Electric Power and its parent company Unisource. Given the infinite permutations of possible financing plans, it is impossible to predict the implications for existing creditors. The Unisource acquisition appears, on first inspection, to adopt a transaction structure which avoids deterioration of the utility's creditworthiness; but, generally, leveraged acquisitions result in credit downgrades. Potential buyers are likely to include highly rated energy firms and private equity investors and leveraged acquisition funds.

Other inflection points in the longer-term are largely related to events at parent and affiliate companies. On the negative side would be a return to the pursuit of growth on the part of utility parent companies that could ultimately impair the ratings of regulated utilities as was the case in the 1999-2001 timeframe. On the positive side, improvement in the supply/demand environment could favorably impact affiliate generating companies and positively impact those companies whose ratings are currently constrained.

Natural Gas Prices

Forecasters predict that natural gas prices will remain high and volatile.

Forecasters are predicting that relatively high gas prices (in the ranges of $4-6 per mcf) will maintain production at around 50 billion cubic feet (bcf) per day level over the five-year time frame, a decline from estimated 2003 production of 52 bcf per day. Incremental LNG capacity at the four existing U.S. receiving and re-gasification facilities is expected to make up for the small decline. Analysts assume that Canadian imports will remain essentially flat. Consumption by power plants will increase while high prices will result in the reduced usage of natural gas as a feedstock for industrial processes (so-called demand destruction). U.S. demand then should average approximately 61-63 bcf daily, depending on the level of industrial demand destruction.

Against this back-drop, experts foresee a continuation of high volatility and relatively high price levels for natural gas over the five-year outlook. Volatility will result from periodic supply-demand imbalances and constraints on deliverability until 2008 when the first of the green field LNG projects start up. During this period, with industrial demand destruction keeping a lid on prices, gas prices will often be nominal $4-6 per mcf.

Conclusion

New coal-based plants require a large amount of capital – in excess of $500 million for a typical plant. An investor can only build such a facility if it is able to raise the necessary capital to finance the project. This depends on the willingness of the financial community to lend money to the investor. Experts in the financial community believe that the outlook for IOUs – as well as wholesale generation companies, diversified energy merchants and energy traders – is generally stable. Therefore, if a project is economically viable, it is expected a power plant developer should be able to borrow the funds to build the plant. However, there are fundamental structural differences between the IOUs and the merchant and independent power producers, and those differences must be recognized in considering the financial issues that impact the decision whether or not to construct new coal-based facilities**.**

Section 5: Environmental, Permitting and Regulatory Issues

Permitting Issues

Obtaining an air permit for a new coal-based power plant is a critical step that must be completed before construction can begin. For plants located at greenfield sites (where there are no existing emissions that can be reduced to offset the new emissions), the new unit will be required to obtain a new source review (NSR) air permit. This is an important process because it provides all stakeholders, including the project team, EPA, state environmental regulators and the public an opportunity for input to the process to insure that the plant design incorporates state-of-the-art emission control equipment to minimize impact on the local, regional and national environment. However, the process is complicated and has built-in inefficiencies that can tax the resources of all of the stakeholders involved and can result in significant delays.

Permitting a new plant is complicated and has built-in inefficiencies that increase costs and cause delays in constructing a new plant.

For the criteria pollutants such as SO_2 and NO_x, depending upon whether the plant will be located in an attainment or non-attainment area, the project team must go through an analysis to define the Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) on a case-by-case basis to minimize these emissions. Even though there are national standards for these emissions, this analysis determines whether there have been any significant advances in the control technology that need to be included in the equipment for the new power plant. Once this is completed, it is submitted to the responsible permitting agency (usually the State's environmental regulatory authority) for review.

Since criteria pollutants have been regulated for several years, the BACT analysis can be supported by the performance of emissions control equipment at existing plants. One of the resources available to the project team and the state is a BACT Clearinghouse that is maintained by EPA. The BACT Clearinghouse provides information regarding permitted emission limits at similar sources. The availability of these data is very important because it means that the equipment is commercially available and has been permitted for use on similar sources. In some cases, the emission limits will be lower than those currently being achieved.

For emissions of hazardous air pollutants (HAPs) that are not subject to current federal new source review standards, a different analysis is performed to determine the Maximum Achievable Control Technology (MACT) for each potentially toxic material on a case-by-case basis. Although this case-by-case MACT analysis is similar to the BACT analysis, it is much more subjective and complicated because it addresses control of emissions that may never have been specifically controlled before. MACT analyses recently performed on new coal-based power plants have resulted in very aggressive limits on emissions such as acid gas emissions, mercury and other trace metals.

Because there are limited operating data on which to base the case-by-case MACT analysis, the process is much more controversial because of the uncertainties involved. For example, the permit for the new MidAmerican Energy Council Bluffs Powder River Basin (PRB) coal-based plant required the BACT analysis to address criteria pollutants, including SO_2 and particulates (PM_{10}), and a review of the MACT equipment for controlling mercury emissions. The Iowa Department of Natural Resources concluded that the BACT equipment for PM_{10} and SO_2 emissions was a spray dryer absorber (SDA) followed by a fabric filter (FF) and that MACT for mercury was activated carbon injection (ACI) equipment capable of feeding AC at 10 lbs/Macf. The emissions limits for the BACT analysis were based upon long-term performance data on SDA/FF systems on existing plants burning PRB coal. However, determining the MACT limit on mercury involved speculating on mercury removal based on performance measured during two one-week-long test programs; one involving a plant with similar equipment but a different coal type (ACI with a SDA/FF on lignite), and another involving a plant with different equipment but a similar coal (ACI with an ESP on PRB). The resultant air quality permit stipulates that the MACT equipment will obtain 83% mercury even though there has never been a test of this specific equipment and coal and neither of the two referenced (but different) configurations obtained mercury removal levels this high.

The state then reviews the BACT and MACT analyses and negotiates with the power plant developer on equipment and emission limits. It should be noted that for a new power plant, these reviews are a massive undertaking by the state that taxes financial and personnel resources. Since there have been so few new coal-based power plants built since the early 1980s, state regulators have little or no experience with such projects. As a result, this requires a lengthy review period.

Once the state makes their determination on equipment and limits for each pollutant, a draft permit is published for public review, which includes EPA and possibly Federal Land Managers (FLMs). This represents a very involved process because every detail is open for public comment including emission limits, types of control equipment, procedures for demonstrating the technology, averaging times, and test methods for making the measurements to demonstrate compliance. The measurement techniques represent a significant area for controversy – especially for newer emissions in which often there is not a universally accepted reference method. For example, the most common approach for measuring condensables is EPA Method 202, which has very well-documented problems in which related compounds are formed in the liquid sample collectors and are reported as emissions.

The permit timeline can be further extended, by those opposed to the new power project beyond the public review period through administrative protests of the final decision by the state. Once the administrative processes are exhausted, opposition can create further delays by filing lawsuits and injunctions in the judicial system, which creates timelines outside the control of the state environmental regulators and the project team.

Because of the subjectivity of the BACT and MACT analyses, it is possible that EPA or environmental regulators in neighboring states will disagree with the permitting authority's conclusions. This creates the possibility for additional delays. In fact, neighboring states can further delay the project by filing for judicial relief related to the transport of emissions across state lines. In addition to EPA and neighboring states, delays can be created by other government entities such as the FLMs.. The FLMs may become involved in the permit review process if there are potential visibility issues in National Parks or other Class I areas. The FLMs Quality Related Values Workgroup Guidelines (FLAG) were established in late 2000 to help determine the impacts of proposed projects on visibility in Class I areas. The FLAG method is being implemented in a way that threatens state authority to issue permits as FLMs exert their authority to protect visibility in Class I areas. As FLAG is currently being applied, it is greatly impeding the orderly permitting process of power plants throughout the nation.

Once the air quality permit is obtained, the final hurdle can occur when the project team has to negotiate with vendors of the emission control equipment that will be purchased to meet the required emissions limits. This is especially true for the MACT emissions, because in many cases the vendors will be asked to guarantee performance of equipment for emissions that have never been controlled before or to maintain low emission levels that have not yet been achieved. This is further complicated by the controversies around the measurement techniques that will be used to define the guarantees and demonstrate compliance.

Recommendations to Eliminate Hurdles

To determine how the inefficiencies of the air permitting process can be improved, it is first necessary to appreciate how emissions control technology is developed for the power industry. Since the first Clean Air Act of 1970, the power industry has gone through several rounds of implementing emission control technologies for PM, SO_2, and NO_x. In each case, there were very similar experiences as the new technology was applied to this complex industry, including:

- Unexpected reactions between flue gas constituents and the chemical reagents added to control the pollutants;
- Differences in coal characteristics and plant operating conditions causing wide variation in performance;
- Significant O&M problems that did not show up until after long-term operation; and
- Secondary effects on other components of the power plants – examples include higher carbon in the ash from low-NO_x burners, ammonia in the ash from SNCR and SCR, and changes in characteristics of the concrete produced when new chemicals are collected with the fly ash.

In all of these cases, the problems that resulted from the new technology had a significant impact on the reliability of power generation. The plants were forced to operate at reduced loads and suffered many unplanned shutdowns for maintenance and repair. Over time solutions to these operating problems were developed and the technologies now operate more reliably and successfully. The severity of the impact of the initial problems, both in costs to the power consumer and in the reduction of available capacity, depended upon how widespread the technology was applied during the early adopter phase. For example, hot-side ESPs have cost the industry over $1 billion - after early success, the technology was quickly applied to 150 power plants before a fatal flaw was discovered.

Hurdles and delays in permitting must be identified and addressed to facilitate the construction of new coal-based plants.

One of the difficulties with implementing new emission control technology is that the equipment is so massive. For example, emission control equipment for a 500 MW plant must treat two million cubic feet of flue gas every minute. To minimize the potential detrimental impact of new emissions control technology on the capacity of electrical power suppliers, history has taught us that it is necessary to go through the following phases:

- **Laboratory testing**: provides a cost-effective means to determine general feasibility and test a variety of parameters.
- **Pilot-scale**: test under actual flue gas conditions, but at reduced scale.
- **Full-scale field tests**: scale up the size of the equipment and perform tests under optimum operating conditions to define the capabilities and limits of the technology.
- **Full-scale field tests at multiple sites**: each new site represents new operating conditions and new challenges.
- **Long-term demonstrations at several sites**: Some problems don't show up until the first year or so of operation.
- **Widespread implementation**: Problems will still be found at new sites, but most of the fatal flaws will have already been discovered and resolved.

If an attempt is made to accelerate technology development by skipping these steps, there will be significant risk that operating problems could arise that will lead to untimely shutdowns of the plants using the technology. As a result, the process of implementing new technology in the power industry is a

10-15 year process and represents significant risk to the developer and the user at each stage. Incremental equipment modifications and improvements in operations can be accommodated much faster, but they still require three to five years for widespread implementation.

Changing BACT, MACT, and other emission standards creates uncertainty in the development of a new plant.

Therefore, a significant improvement in the air permitting process can be made if the stakeholders acknowledge the realities that changes in emissions control equipment can only occur at a minimum on a 3-5 year timeframe. Currently, the same battles over BACT and MACT equipment and limits are fought for each new power plant project. This taxes the resources of all involved, including the project teams, the state environmental regulators and the environmental activists that may scrutinize the project. If there are 30 new power plant projects being reviewed, there will be 30 different debates over the permit requirements. Because different organizations and individuals perform the analyses, there is a significant amount of subjectivity in the results.

An improved process would provide a mechanism to perform the BACT and MACT analyses on a national level every two to three years. This process would involve all of the stakeholders, including the power industry, state and federal environmental administrators, citizen and environmental groups, emissions control experts and equipment vendors. All of these organizations could concentrate their resources to address the issues at a national level rather than dilute their efforts to deal with the same issues on a project-by-project basis. This would also eliminate subjectivity in the process. The result of this process would be a consensus agreement on BACT and MACT equipment and levels – possibly subcategorized according to boiler design and coal type – that would remain in effect for a prescribed time period and would apply to all new coal-fueled power plants being permitted.

Another recommendation to accelerate the permitting is to use the BACT and MACT processes to define the emissions equipment for the construction permit, but delay setting the emissions limits until the equipment is installed, operating and optimized as part of the Title V process to define conditions for the operating permit. For a given type of emission, the BACT or MACT equipment can be defined, including its key engineering design parameters, based upon experience gained from existing equipment. The difficulty and uncertainties come when trying to predict the explicit performance of the equipment that can be obtained on a new boiler/coal combination. There are advantages to this approach, several of which are discussed below.

It **avoids lengthy debate** on issues that have large uncertainties and minimal data to support decisions. Emissions control equipment can be specified and purchased with warranties without requiring guarantees that may be impossible to meet.

It also **provides potential environmental benefits** by allowing the possibility that the emission limitations set during the Title V process could actually be lower than expected based upon unexpected favorable operating conditions or improvements in technology. As an example, the equipment defined for mercury control in the referenced case study for the Council Bluffs plant was an ACI system capable of feeding 10 lbs AC/Macf upstream of the SDA/FF. From the data available at the time of the permit, this offers the best opportunity by far for maximum mercury control. The same decision would be true today (a year later). However, what is unknown at this time is the reduction in mercury emissions that will occur with the coals to be burned in the future. If the construction permit only contained a definition of the equipment, the project could begin and the procurement of emissions control equipment would take place requiring only operating warranties for the equipment. Once the equipment was installed and operating, optimizing operation would define the emissions limits. This process could take advantage of any improvements in the mercury control sorbents that might have occurred during the three-to-five-year construction period. As a result, the final mercury emission reduction required in the permit could be greater than the 83% removal predicted years earlier by the permit review team. On the other hand, if the 83% removal is not achievable, the performance of this equipment would still be by definition the "maximum achievable" at the specific site.

The purpose of moving the emission limits from the construction permit to the operating permit is to **provide flexibility in dealing with uncertainties** associated with controlling new emissions on new power plants.

Uncertainty about environmental regulations can impact the ability to finance a new plant.

It should be noted that inflexible environmental regulations can impact the ability to obtain financing for the project. If guarantees are not obtainable for all emission standards, it is unlikely that capital investment could be justified. The owner/operator of a power plant must also confront the uncertainty of future environmental regulations which could lead to excessive capital costs, unforeseen O&M cost impacts, or even render the power plant uneconomical to operate before a reasonable rate of return could be earned for the investment. The life of a new coal-based power plant is expected to be at least 50 years, and the investment cost is expected to be on the order of $1 billion. Providing the investor with some assurance of the regulatory certainty concerning what the limits will be for the emissions from that plant – both at start-up and for a reasonable term – would remove an impediment to making such an investment. For example, if the ash disposed from a 500 MW plant were to be re-classified from solid waste to a hazardous waste, the cost impact on the plant operation would be in the range of $3-$5 million annually. If an investor expects that regulations will be promulgated in the near future which would mandate removing CO_2 from the exhaust of the plant, the investor is not likely to invest in a coal-based plant, since current technology for removing CO_2 from the exhaust of a conventional coal-based plant is uneconomical.

Other recommendations for accelerating the process include:

- As allowed by some states, provide an option to pay a premium on permit fees for an accelerated review. The state could use the increased fees to support additional resources that will be needed to handle a large project such as a new power plant.
- Increase certainty with emissions regulations, such as more comprehensive and more up-to-date new source performance standards (NSPS).
- More quickly establish reference measurement methods for new emissions.
- Limit the number of opportunities to appeal (administrative and legal) or reduce the timeframe associated with these processes.
- Keep the BACT Clearinghouse more current and complete.
- Provide assurances that additional emissions reduction technology would not need to be retrofitted into a new plant for a certain number of years (provided that the plant is built in compliance with current regulations), even if the regulations mandate emission reductions from newer plants.
- Withdraw the FLM's FLAG guidelines and subject them to appropriate notice and comment rulemaking. This process should include an evaluation of whether or not any guidelines are needed for Class I areas considering already very stringent BACT/MACT emission standards and Class II air modeling requirements included in the Clean Air Act.

In addition to the recommended procedural changes to accelerate the permitting and construction processes, there are a number a things that project teams can do to shrink the timeline. These suggestions relate to anticipating all possible interest groups who will have a stake in the project, and getting their input early in the process. The project team should get input from FLMs, neighboring states and vendors of emission control equipment to define current capabilities of the equipment, achievable emission limits and possible guarantees.

It should be noted that recommendations requiring changes in the BACT and MACT processes could require modifications to the Clean Air Act for implementation.

Mercury Regulatory Uncertainty

The federal government's approach to regulating mercury emissions from coal-based power plants is a pertinent and topical example of the difficulty in anticipating environmental regulations by those who would invest in new generation capacity. In the Clean Air Act Amendments of 1990, EPA was charged with preparing a Report to Congress (RTC) within three years on the appropriateness and necessity of regulating emissions of hazardous air pollutants (HAPs), including mercury, from electricity generating units. At the time, very little was known about HAP emissions from power plants, and the methodologies for measuring them accurately were largely non-existent. Specifically, methods for measuring mercury at the exceptionally low concentrations found in coal and for making speciated mercury measurements in flue gas were just being developed. Therefore, much of the early effort was concentrated on making emission measurements from a few sources while refining the measurement methods. When the RTC was completed (in 1998, five years later than called for in the Act), EPA found no indication of increased health risk from any of the listed HAPs other than mercury, which it concluded needed more study.

New proposed mercury reduction requirements add a new level of uncertainty in the construction of new coal-based power plants.

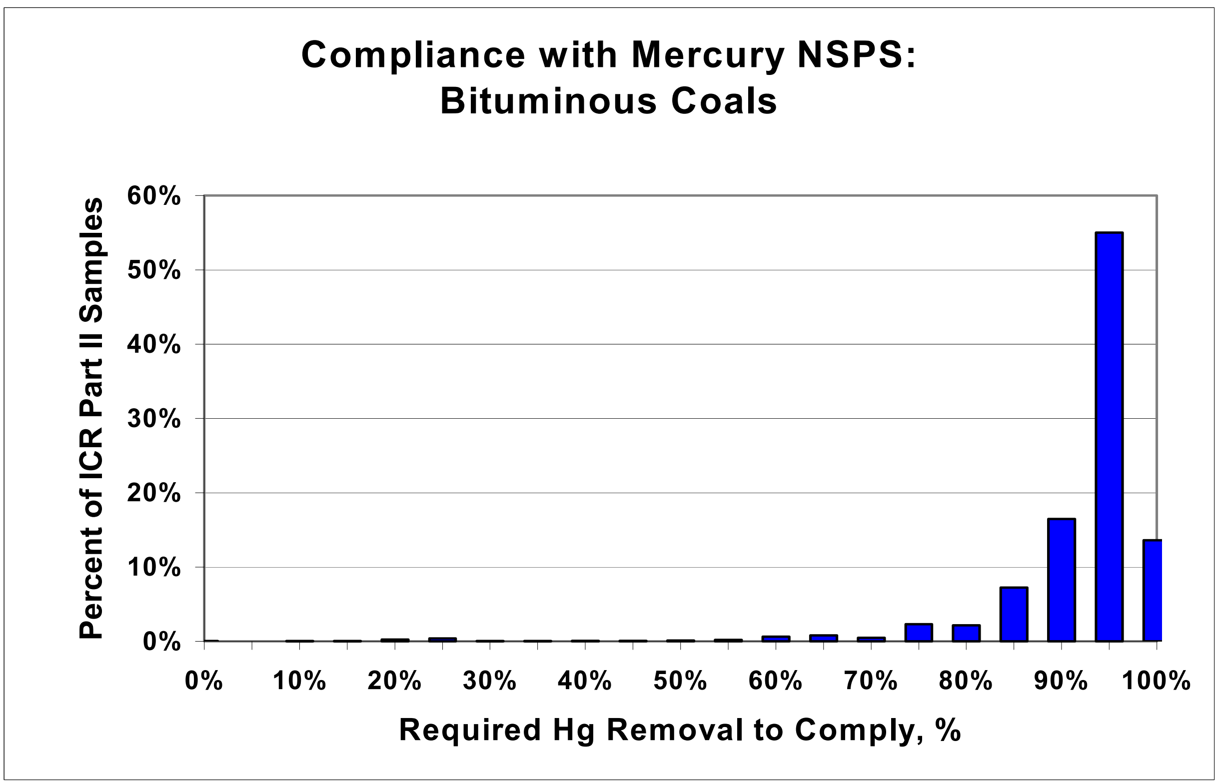
In December 2000, EPA finally made a regulatory determination that there was sufficient evidence to require reduction of mercury emissions from coal-based power plants. EPA based its conclusion, in part, on mercury emission data collected in 1999 under a program known as the Mercury Information Collection Request (ICR). Under a court-approved consent decree, EPA proposed a draft rule in December 2003. The proposed rule exemplifies the difficulty in anticipating and planning for the consequences of a regulatory determination; rather than propose a single rule, EPA proposed three separate options. One would set MACT floor limits (for existing sources) and NSPS limits (for new plants) to be met on a unit-by-unit basis. The other two rule options would implement cap-and-trade programs, but with different caps, allowance allocations and implementation schedules. EPA would implement one of the proposed cap-and-trade programs nationally, with allowance allocation procedures similar to those of the Title IV SO_2 program. The other would be implemented by the individual states, under the equivalent of a State Implementation Plan (SIP) program. It would allow the states to "opt out" of trans-boundary trading, and would leave it to each state to allocate an allowance budget to individual sources. The final compliance dates for these options vary from as early as 2007 to as late as 2018. Questions have been raised about the legality of EPA's authority to regulate under the cap-and-trade provisions, raising the likelihood of protracted litigation regardless of the final rule that EPA proposes. EPA is required to issue a final rule by March 2005.

The emission limits (MACT, NSPS or caps) proposed in the rule introduce further uncertainty. They are based on little data of questionable quality. EPA based the proposed rules on mercury emission sampling done on 80 coal-based electricity generating units in the1999 ICR program. These samplings consisted of three measurements of speciated mercury emissions done using the draft "Ontario Hydro" flue-gas sampling method. None of the plants used mercury-specific control technology, so the mercury reductions achieved were the "co-benefit" of technology employed for SO_2, NO_x and PM.

Research is being done on mercury-specific control technology, mostly with Department of Energy funding, but the technologies have yet to undergo long-term commercial demonstration in an adequate variety of circumstances. The Department of Energy goals are to have mercury control technology capable of 50-70% reduction available by 2007, and to have technology capable of 90% reduction ready for "commercial demonstration" starting in 2010. Meeting these goals will depend on the success of the research, and on the continued availability of funding to conduct sufficient long-term demonstration tests.

To illustrate the risk to a potential investor in new generating plants, consider the new source performance standard (mercury emission of 0.6 lb/TBtu) that EPA proposed for bituminous coal-based power plants. The average mercury content of bituminous coals mined in the U. S. is 8.6 lb/TBtu (as sampled in EPA's 1999 ICR program). Therefore, to comply with the NSPS, a plant burning the average bituminous coal would need to achieve 93% mercury reduction. As shown below, 55% of the coals would require a 90-95% reduction, and 14% would require greater than 95% reduction. Given the uncertainty in achieving even a 90% reduction by 2010, the imposition of a standard requiring more than 90% reduction on 70% of U. S. bituminous coals clearly would inhibit – if not eliminate – investment in new coal-based plants using combustion-based technologies. The proposed NSPS limits for subbituminous and lignite coals would have similar results.

Figure 5.1
Compliance with Mercury NSPS with Bituminous Coals



Given the uncertainty about the form of the final regulation, the level of mercury control it will require, and the unavailability of proven commercial technology at a performance level necessary to meet the rule, there is an understandable reluctance among the investment community to finance new coal ventures. This is amply illustrated in a letter of March 30, 2004, from Lehman Brothers to Peabody Energy, Inc. concerning potential financing for Peabody's Thoroughbred and Prairie State power plant projects. The letter was provided by Peabody as an attachment to their public comments on the mercury rule, EPA Docket OAR-2002-0056. In it, Lehman says that "the proposed Environmental Protection Agency (EPA) regulations for mercury removal create some significant uncertainty for both electric generators and the financial community. . . . emissions control vendors will need to provide substantive guarantees that insure the required mercury emission levels can be met over the life of the plant. . . . We are unaware of any actual long term demonstrations at those high levels or vendors willing to provide unqualified and financeable guarantees for mercury removal that meet the proposed EPA standards. . . . Without demonstrated experience and substantive vendor guarantees for mercury emission limits, financing for new coal power plants will be problematic at best and perhaps not possible at all."

Regulatory Issues, Planning for a Robust Electricity System

In most states, electricity is still a regulated commodity. Even in "deregulated" states, there is significant regulation in the transmission and distribution of electricity. Therefore, the PUCs continue to play a significant role in establishing the criteria that determine whether a new power plant will be built and what technology would be used for a new plant, hence the fuel choice. The case study about We Energies in the subsequent chapter demonstrates that, while the PUC did not select the actual fuel type or technology, it had the final say on the technology and fuel choice based on a certain set of criteria.

As noted in the discussion about the 3-Party arrangement, it is important to involve the state regulators in the planning process for a new power plant. The large capital investment in a new coal-based power plant impacts the rates that customers pay for electricity. State regulators would likely take the position that imposing the recovery of a new advanced (but more expensive) coal-based plant in one utility's service territory may place an undue burden on those ratepayers. Therefore, absent incentives to bring the equivalent cost of the new advanced plant down to the level of lower-cost alternatives, it will be difficult to obtain approval to build a new coal-based plant in a single utility service territory. Further, where wholesale competition exists for electricity, the addition of new generation by Independent Power Producers is done based on specific wholesale market signals. These two situations have led to short-term incremental addition of power plants without consideration to the long-term strategic needs of the nation.

When long-term strategic considerations are incorporated into the process, planning, system reliability, siting and fuel choice are interlinked and cannot be viewed in isolation. Planning for a robust electricity system ideally would be in the form of a nationwide integrated resource process (IRP) – taking into consideration load growth, supply options including generation, conservation and transmission/distribution network needs. A properly crafted planning effort would be able to transcend the electric regulatory structure on a state-by-state basis (i.e., regulated vs. deregulated) while ensuring that reliable electricity is available to the users of the networks. Economic considerations for the maintenance and expansion of the system are separate but linked issues.

Lack of coordinated regional planning is an impediment to the construction of new coal-based power plants.

Planning has historically been done on a company-by-company basis, and, at most, a statewide look. While a nationwide planning effort, or at least on an interconnection basis, is ideal, a more realistic planning view and effort should concentrate on sub-regions of the North American continent. There are many ways to define these regions. One method currently being pursued would use a regional transmission organization (RTO) footprint to identify regions. Decisions by federal government agencies have considerably slowed the progress in RTO development and put in question the current viability of this approach for planning. In addition, the planning processes endorsed by the individual RTOs, as well as coordination between RTOs, is not convincingly optimal.

It is also problematic that required planning horizons are not workable. FERC, in their Standard Market Design Order, did encourage regional choice and diversity as an option. However, planning horizons that have been prevailing have been short and unreasonable for needed baseload plants in some parts of the country. The generation construction that has occurred to date is generally gas-fired peaking facilities. The planning horizon and timeframe for construction of such facilities is relatively short. If that horizon is found to be reasonable, the country will not be able to meet the necessary baseload growth with the appropriate generation mix.

Planning for new coal-based power plants on a regional basis such as geographical areas or coal basins can lead to a superior planning process.

Reserve margins (which is based on the difference between the "peak" load at any given time and the installed capacity of a utility) have typically been the determinant of when new capacity is required in a utility service territory. As discussed at the end of Section 2, the type of generation required to meet a reserve margin typically operates at a very low capacity factor, and therefore is conducive to low capital-cost technology such as combustion turbines. However, changes in usage patterns are reducing the difference between average loads and peak loads. Much of the increase in electricity usage we have experienced in the country is due to information systems requirements and computers. This type of load is typically around-the-clock, thereby increasing overall consumption, but not necessarily affecting the peak significantly. In addition, energy efficiencies that have been gained in all aspects, industrial applications as well as residential and commercial uses, have resulted in a relative decrease in the peak usage compared to overall growth. Recognition of this paradigm shift by the regulators is expected to provide a more favorable view of coal-based, baseload plants rather than peaking plants such as combustion turbines.

Another concept is to tie load, load growth and fuel source to a geographical region. Coal basins, for instance, could serve as the defining area for a regional IRP effort. This would allow for tailored technology considerations as well as for the accompanying economic analysis for resource deployment. This would provide a measure for what an appropriate planning horizon might be in any given region. It puts some dimension on fuel mix and diversity, which can then lead to a desired planning time horizon.

Other Infrastructure Issues

Building new coal-based power plants will require a skilled workforce of engineers, construction labor and operators.

As was discussed in this report, uncertainty is an impediment to investment of capital. There are additional issues concerning the infrastructure that lead to uncertainty that warrant consideration. The construction of new power plants requires the availability of skilled construction labor to build a facility and skilled operators to safely operate the facility. Because not many new coal-based plants have been built, there has not been a strong attraction of skilled boilermakers. Many older and experienced workers have retired from this business and replacements are difficult to find or retain. A nearly two-decade absence of need for construction labor to erect large central generating stations has left a lack of experienced riggers, welders and fitters required for the construction of new power plants. Further, many of the experienced engineers have retired, and many well-known architect/engineer firms with long histories of managing complex, fixed-price turnkey projects no longer exist.

For more than a decade, the number of high school students matriculating to engineering curricula has dropped. The pattern of bachelor's degrees awarded during this period has shifted significantly. Engineering and engineering technologies declined 4% between 1990 and 1995, with a further 7% decline between 1995 and 2000. Some engineering schools, in an attempt to remain viable, have "engineered" their curricula to deal with a less prepared student body or one marginally interested in technology, and then only in relation to a perceived need to evaluate technology on economic grounds, not to participate in creating it. Therefore, uncertainty concerning the availability of skilled labor to design, construct and operate new coal-based power plants must be considered to ensure that new coal-based power plants can be built and operated properly.

Other factors also create uncertainty to an investor in new coal-based power plants. FERC and states have failed to adequately deal with transmission congestion that must be addressed in siting a new plant. Availability of affordable coal is critical to the long-term operation of a power plant, yet there are growing regulatory hurdles to the development of new mines that will be required to fuel new plants. Finally, domestic manufacturing capability has declined, requiring that many components used in a new coal plant must be fabricated overseas, which can place added risk of delivery and stable prices.

Conclusion

Environmental and regulatory issues transcend the financial issues discussed in the previous sections of this report. If an investor believes that a plant cannot be permitted, the plant will not proceed even if there are other financial incentives. Further, uncertainty of the permitting process may result in the selection of a gas-fired plant over a coal-based plant, all other considerations being equal or close. The length of permitting time, as well as redundant permitting requirements, has created impediments to new construction. Even with new coal-based generation meeting, and in some cases exceeding, the most stringent emission control requirements and efficiency standards, time from project initiation to start up is routinely extended due to delays in the permitting process that do not result in any changes to the plant's emission control systems. This causes uncertainty in the investment community, with higher perceived risks in developing new coal-based plants.

Over the past three decades, the prevailing regulatory approaches have led to the retrofit of high capital cost emissions control technologies at existing coal-based generating plants. In order to avoid the risk of stranded investments and the uncertainty of investing in new plants, power plant operators have taken steps to extend the life of existing plants. This has also made it more difficult for new plants to enter the electricity market at a price competitive with older, less expensive coal-based plants.

The uncertainty of future environmental regulations has complicated the decision as to whether or not to repower or replace existing coal-based generation. This situation is exacerbated by the uncertainty surrounding the issue of carbon management. Past incentives have facilitated research, development and demonstration of advanced, clean and efficient coal-based technologies leading to significant advancements in both environmental performance and generation efficiency. However, these technologies require additional support for deployment to achieve significant market penetration.

Section 6: Case Studies

The preceding sections of this report provide discussions and analyses of issues which impact the construction of new coal-based power plants. This section provides case studies to highlight those issues as they relate to actual experiences with permitting, construction and operation of new coal-based electric generation facilities.

CASE STUDY #1
Elm Road Generating Station
Milwaukee County, Wisconsin
We Energies

We Energies received regulatory approval to construct two 615-MW PC plants, but was denied approval for a 600-MW IGCC Plant.

Overview and Current Status of Project
We Energies'[1] proposed Elm Road Generating Station (ERGS) consists of two 615 MW SC PC generating units located adjacent to the Oak Creek Power Plant in Milwaukee County, Wisconsin. In November 2003, the Public Service Commission of Wisconsin (PSCW) issued a Certificate of Public Convenience and Necessity (CPCN) allowing construction of ERGS Units 1 and 2 to be in-service in May 2009 and May 2010, respectively. The PSCW denied the CPCN for a 600 MW coal-based IGCC unit proposed for 2011.

As of March 30, 2004, ERGS has received an air permit but still needs several water, wetlands and other site-related permits. Numerous lawsuits involving the PSCW and the Wisconsin Department of Natural Resources (WDNR) brought by parties opposing the project are pending. Construction is expected to start in the second half of 2004.

Project Chronology
Wisconsin is an electrical island with only four frequently constrained high-voltage transmission connections to Minnesota and Illinois. Unlike the region in general, Wisconsin does not have a surplus of generation of any type. No baseload power plants have been built in the state since the mid-1980s. Load growth has been met exclusively with new gas-based units. Retail access has not been pursued in Wisconsin although the state's utilities have divested their transmission assets and joined the independent American Transmission Company.

ERGS was proposed in 2000 as part of a broader *Power the Future* initiative that committed Wisconsin Energy Corporation (the parent company of We Energies) to invest $7 billion in "a comprehensive approach to address electricity supply and reliability issues for We Energies' customers in a way that considers both the economy and the environment," according to www.powerthefuture.com. The web site explains that "Power the Future expands power production to meet growing demand, improves existing power plants for increased efficiency and reduced emissions, and upgrades power delivery to help keep the lights on."

[1] Wisconsin Energy Corporation is the parent holding company of two utilities: Wisconsin Electric Power Company and Wisconsin Gas Company which jointly do business under the brand name We Energies.

A large coalition supporting all or parts of the Power the Future project took shape in 2000 and 2001, eventually encompassing industrial energy customers, residential customers, some environmental groups, labor unions, other Wisconsin utilities, Wisconsin municipal utilities and cooperatives, and some renewable energy advocacy groups. This broad coalition remained roughly intact throughout the PSCW CPCN process and remains a valuable supporter of the project as it moves forward.

Several potential obstacles were avoided early in the project because We Energies was willing to compromise on the structure, timing and size of the project as it worked to form a broad-based coalition supporting the project. The core components of the plan remained unchanged: invest in new gas and coal generation to meet future needs. The company approached the addition of new generating capacity as part of an overall transition towards expanding and improving its generation portfolio, including retiring older generation and investing in emission upgrades to intermediate-aged coal units.

The initial *Power the Future* proposal, which was not well received by customer groups, was structured as an IPP-type power purchase agreement that would fall under the jurisdiction of the FERC. In subsequent negotiations, a broad coalition supported a non-utility affiliate (We Power) owning and building new power plants with the regulated utility (We Energies) leasing and operating the plants for the term of the lease. Wisconsin Energy Corporation is also the parent company for We Power. The unifying goal of the coalition's effort was to keep power plant regulation at the state rather than the federal level, while allowing utilities financial certainty through a long-term, PSCW-approved lease. Legislation allowing such transactions was proposed and debated in 2001 and, with strong support from the customer coalition, the Leased Generation Law was passed and signed into law in September 2001. The key risk-mitigating feature of the Lease Generation Law is that PSCW approval of a lease ensures full recovery of lease costs in utility rates.

In early 2001, Wisconsin Energy Corporation earned valuable labor union support for the projects with the signing of a project labor agreement with the Milwaukee Building and Construction Trades Council that ensured all *Power the Future* construction projects would be staffed by union labor. Union labor support for the ERGS project was critical in the battle for headlines and as a strong and vocal counterpoint to the opposition at numerous public forums and hearings.

One of the primary opponents of the project was a large Racine manufacturing company and its billionaire owner who ensured a well-funded legal defense team and significant public media exposure. Their primary issues were the local environmental impacts of the ERGS project, particularly mercury and fine particulate emissions, compared to gas-fueled generation. The high profile opposition probably neutralized some portion of the local business community that otherwise might have supported the local utility.

Early in the project, ERGS gained two prospective co-owners, Wisconsin Public Power, Inc. and Madison Gas and Electric. Each prospective co-owner has an option to own a 50 MW share of each unit being built at Oak Creek. In addition, ERGS gained support from Wisconsin's municipal and cooperative entities by making up to a total of 50 MW of the We Energies system energy per coal unit available for purchase through an open season offering.

In 2001, We Energies committed to serving 5% of its Wisconsin retail load from renewable energy sources by 2011, far exceeding the state's renewable portfolio standard. We Energies also earmarked $20 million to encourage and support customer-based energy efficiency activities over 10 years. The renewable and energy efficiency commitments were valuable complements to the power plant additions and provided the necessary counterpoint to base-load generation.

On February 1, 2002, Wisconsin Energy Corp. filed its Certificate of Public Convenience and Necessity (CPCN) application and associated affiliated interest agreements to build the 1,830 MW ERGS (1,230 MW of SC PC and 600 MW of IGCC) and 1,090 MW Port Washington (Wis.) Generating Station gas combined cycle plant (PWGS). The PSCW decided to process the gas and coal applications separately.

The gas-fueled PWGS application was deemed complete in April 2002. In December 2002, the PSCW issued the CPCN order approving the PWGS plant and associated lease. The 20-year lease includes a fixed price guarantee and allowed a 12.7% return on investment assuming a 53/47 equity-debt ratio. It also includes a current return on construction work in progress, recovery of pre-certification expenses, and liquidated damages if the project is late or performs below guarantee. In approving the PWGS lease, the PSCW acknowledged that We Energies contention "…that We Energies will not be allowed sufficient return on a traditional rate base investment to compensate investors for the risks associated with the plant. Although the rate-based option is clearly one feasible alternative based on the evidence presented in this case, the Commission concludes that leased generation financing is in the public interest." PWGS construction began in mid-2003 for the first unit with a July 2005 targeted in-service date. The second unit will be in service by summer 2008.

The coal-based ERGS application needed several rounds of additional information before the PSCW deemed its application complete in November 2002. In Wisconsin, the CPCN process must be finished within one year of the date the application is deemed complete. Given the various Environmental Impact Statement (EIS) and regulatory review and notice requirements, the one-year clock is a strong motivator for the parties and the PSCW to move through the regulatory process expeditiously.

The joint PSCW-WDNR Draft EIS was published in April 2003. The PSCW received comments from about 300 parties or individuals. The 800-page Final EIS was issued in August 2003. Two weeks of technical hearings and three days of public hearings were held in August and September 2003.

The PSCW issued the ERGS CPCN and lease approval order on November 10, 2003. The CPCN was conditioned on receiving the necessary environmental permits, planning for 55 MW of new energy efficiency programs, and an updated needs assessment for the second unit. The PSCW-approved 30-year ERGS lease allows a 12.7% return on investment assuming a 55/45 equity-debt ratio and a 5% cap on cost overruns. The ERGS lease also includes a current return on construction work in progress, recovery of pre-certification expenses, and liquidated damages if the project is late or performs below guarantee. At the end of the initial 30-year lease term, We Energies has the option to renew the lease at a substantial discount, terminate the lease, or buy the facility, subject to certain tax limitations.

Construction activities at the site will begin in late 2004 or early 2005 to meet the May 2009 and May 2010 in-service dates.

Major Issues for the ERGS Project

1. Need for new power plants

The first hurdle turned out to be the easiest for We Energies and ERGS. The last baseload power plant built in Wisconsin went into service in 1985 while load has been growing 2-3% per year. As a result, there was strong agreement among almost all parties – including our primary opposition – that there was a need for one or more new baseload power plants.

Gas vs. Coal
One of the fundamental issues for new generation was fuel choice. The *Power the Future* initiative included plans to retire an old coal-based plant and replace it with new gas-fueled or new coal-based generation. The opposition argued primarily for gas-fueled plants instead of using coal. The main issues were the economics, reliability and environmental impacts of each fuel.

From We Energies' standpoint, the economic advantages of building coal-based capacity were overwhelming. Long-range planning models run by the PSCW showed a $1.9 billion net present value advantage to building coal-based units compared to an all-gas/no-coal scenario. Detailed analyses of dozens of planning scenarios resulted in the near consensus opinion that there are economic benefits to adding two new coal-based plants in the 2008-2012 timeframe. In the ERGS Order, the PSCW recognized the need for coal-based capacity and compromised on the timing by ordering 2009 and 2010 in-service dates. In their deliberations, the PSCW considered that given the long and arduous application and approval process for a new coal-based plant, rejecting new coal-based units in 2003 would have represented a serious setback and may have delayed future attempts to build coal-based capacity.

Several IPPs were unsuccessful in opposing the PWGS combined cycle plant in 2002 and dropped out of the *Power the Future* opposition group, leaving Calpine as the only IPP proposing to build gas-fueled plants in place of or before new coal-based units. Calpine submitted its confidential bid directly to the PSCW, but later provided copies to We Energies. The most economic Calpine alternative was a 500 MW NGCC plant built in 2007, which delayed new coal-based units a few years. The PSCW rejected the proposal, noting the high proportion of IPP gas generation in Wisconsin already owned by Calpine and the relative financial stability of Wisconsin Energy compared to Calpine.

The underlying coal and gas price forecasts provided by We Energies were closely scrutinized by opposing parties but were ultimately used without modification by the PSCW. The 20-year gas forecast was provided and ably defended by Energy and Environmental Analysis, Inc.

The late-2000 and early-2003 gas price run-ups and the overall high price volatility of the natural gas market were important issues. Consumer groups, particularly industrial customer groups, were supportive of more coal and less gas generation in large part to ensure more stable and predictable electric rates.

Maintaining fuel diversity was also a key issue. After the *Power the Future* additions in 2010, We Energies' generating capacity mix by fuel will be roughly the same as it is today (about 60% coal, 25% nuclear, 10% gas, 5% hydro/other). If new coal-based units were not built, the fuel mix would have become increasingly gas-based. The huge advantage in proven reserves of coal vs. gas was also an important point in favor of coal.

2. Plant Siting
We Energies' Oak Creek site is the best site for a new power plant in the state because it has access to Lake Michigan cooling water, existing rail and coal handling facilities and extensive and underutilized transmission infrastructure. Ever since four old Oak Creek units (600 MW) were retired in 1988-89, the site has topped any list of possible locations for new generation. The large extent of We Energies' property surrounding the Oak Creek Power Plant allowed for the development of several different alternate siting options for the ERGS units.

3. Environmental Issues
The ERGS faced a substantial challenge that needed to be overcome in terms of the environmental perception of new coal generation, particularly as compared to the emission characteristics of natural gas peaking units. The ERGS units, however, include several direct and indirect environmental improvements. The differential between emission controls that are required for new units versus the

existence and characteristics of emission controls for older coal-based units is significant. In addition, greater plant efficiency achieved by new coal-based plant designs means less fuel burned per unit of electrical output, lower emissions and less coal combustion by-products..

As noted previously, the *Power the Future* initiative included a financial commitment to invest in air quality improvements at existing power plants. When these emission reductions are combined with the air quality improvements associated with the addition of the ERGS units, system-wide emissions of SO_2 and NO_x will be reduced by more than 65% and mercury by more than 50% by 2013 compared with year 2000 levels. These reductions come from a combination of coal plant retirements, addition of emission controls at existing plants, and the addition of new, lower-emitting coal and gas units. System-wide emissions of SO_2 and NO_x will be reduced by more than 100,000 tons per year by the time the full *Power the Future* initiative is implemented, and mercury will be reduced by more than 500 pounds per year.

In Wisconsin, the power plant approval processes (CPCN, air permit, water permit, EIS, etc.) at the PSCW and WDNR and other agencies is a complex web of interconnected filings, reviews, comment periods and decision dates. The CPCN approval by the PSCW is one of the first approvals received and is usually conditioned on the applicant receiving subsequent approval from other agencies. A summary of the major environmental areas follows.

Air – The ERGS project (including the IGCC unit) received an air permit in January 2004. (The main permit conditions are shown in Attachments 1 and 2.) All criteria air pollutants were a significant issue and were examined. The air permit process took 25 months and included 46 formal submittals, 16 face-to-face meetings with the WDNR, seven consultants, and $380,000 in permit fees. The opposition spent most of their time addressing mercury and fine particulates.

Water – ERGS will use Lake Michigan's cold water in its once-through cooling system to improve unit efficiency and lower emissions, compared to plants with cooling towers. The project includes building a new intake tunnel bored under the lake extending about 1-1/2 miles out from the shore. Cylindrical wedge-wire screens will be installed at the lake bottom to keep fish from entering the intake structure.

The EPA has recently issued federal standards under Section 316(b) of the Clean Water Act that impose technology-based performance requirements for the location, design, construction and capacity of cooling water intake structures. To comply with the new standards, the current onshore open-channel intake structure currently serving the Oak Creek Power Plant will be modified to share the ERGS offshore intake tunnel. The principal advantage to the offshore intake is to locate the water withdrawal point in an area of the lake that has less biological activity than the current onshore location. The addition of the new ERGS units at the site of existing generating units optimizes the environmental improvements associated with implementing the new federal rules for the entire generating facility.

Wetlands – The site is large enough to accommodate the new units and their associated rail and yard modifications without disturbing significant amounts of wetland habitat. The company has proposed a mitigation plan to compensate for impacts on specific wetland communities which includes a mix of on-site and off-site wetland enhancements and restoration projects.

Coal Combustion By-products – The primary coal combustion by-products produced at the ERGS units are fly ash, bottom ash, and synthetic FGD gypsum. We Energies' goal is to use 100% of these by-products (We Energies coal combustion by-product utilization rate from its existing coal-based generation is 98% and growing). Based on past experience and recent discussions with firms that use and market these materials, the company expects to increase utilization from zero at the start of ERGS commercial operation to 100% over 10 years. An initial need for landfill space will be provided through existing landfill capacity.

4. Jobs

The very positive local economic impact of coal-based power plant construction and operation was important not only to the city of Oak Creek and the area's union labor force, but also to state and local businesses, equipment suppliers, politicians and citizens. The coal plant enjoyed tremendous support from a very broad coalition rallying around the new jobs and economic development benefits as well as reduced air emissions of the ERGS project. Their attendance, testimony and support at public hearings and other forums was instrumental to securing approval from the PSCW.

The planned but denied IGCC Unit in 2011

In the February 2002 *Power the Future* filing, We Energies proposed a third coal-based unit utilizing IGCC technology at the ERGS site to be in-service in 2011. This third coal-based unit was denied a CPCN by the PSCW for two reasons: 1) it was too expensive, and 2) it was not needed in 2011. We Energies and We Power used cost and performance assumptions based on firm quotes, estimates and recent contract experience (see Attachment 3). In the long-range least cost planning models used by the PSCW and We Energies, both SC PC and IGCC units were available options but only SC PC units were selected, both in the base case and in all scenarios (high gas prices, high coal prices, etc.).

We Energies argued that the environmental advantages and promising technology made IGCC appropriate as the third coal-based unit at the site, despite some apparent economic disadvantages. In the end, the PSCW decided only two coal-based units were needed at this time. We Energies remains optimistic that the IGCC technology will continue to mature and will consider using the technology in future generation plans.

FIGURE 6.1
Supercritical Unit Air Permit Limits
ERGS Supercritical Units 1 and 2 Air Permit
Control Technologies and Emission limits for each Boiler

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT	Averaging Time
Carbon Monoxide (CO)	Good Combustion Practices	0.12 lb/MBtu , 742 lb/hr, 3,250 tpy	24-hour rolling average, excluding SU/SD 12-month rolling average including SU/SD
Nitrogen Oxides (NO_x)	Low NO_x Burners and Selective Catalytic Reduction	0.07 lb/MBtu < 5 ppmdv ammonia	30-day rolling average excluding SU/SD 12-month rolling average including SU/SD
Particulate Matter (PM)	Fabric Filter Baghouse, Flue Gas Desulfurization, Wet ESP	0.018 lb/MBtu 20% opacity	Based on a 3-hour block average limit.
Particulate matter < 10 microns (PM_{10})	Fabric Filter Baghouse, Flue Gas Desulfurization, Wet ESP	0.018 lb/MBtu 20% opacity	Based on a 3-hour block average limit.
Sulfur Dioxide (SO_2)	Washed Coal and Wet Flue Gas Desulfurization	0.15 lb/MBtu 4.0 lb/MBtu	30-day rolling average including SU/SD Uncontrolled – 30-day rolling average
Volatile Organic Compounds (VOC)	Low NO_x Burners and Good Combustion Practices	0.0035 lb/MBtu 21.6 lb/hr, 95 tpy	24-hour rolling average, excluding SU/SD 12-month rolling average including SU/SD
Lead (Pb)	Fabric Filter Baghouse and Flue Gas Desulfurization	7.9 lb/TBtu	Based on a 3-hour block average limit.
Mercury (Hg)	Fabric Filter Baghouse and Flue Gas Desulfurization	1.12 lb/TBtu (based on 90% Removal, Final Limit is operational permit)	Stack Testing Coal Sampling & Analysis
Beryllium (Be)	Fabric Filter Baghouse and Flue Gas Desulfurization	0.35 lb/TBtu	Stack Testing Coal Sampling & Analysis
Fluorides (F)	Fabric Filter Baghouse and Flue Gas Desulfurization	0.00088 lb/MBtu	Stack Testing Coal Sampling & Analysis
Hydrogen Chloride (HCl)	Flue Gas Desulfurization	16.2 lb/hr	Stack Testing Based on a 24-hour rolling average
Sulfuric Acid Mist (H_2SO_4)	Flue Gas Desulfurization and Wet ESP	0.01 lb/MBtu	Stack Testing Based on a 24-hour rolling average

CASE STUDY #1
Attachment 2 – IGCC Air Permit Limits
ERGS IGCC Unit Air Permit (but CPCN was denied by PSCW)
Control Technologies and Emission limits for each IGCC Gas Turbine

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT	Averaging Time
Carbon Monoxide (CO)	Good Combustion Practices	0.030 lb/MBtu 624 lbs 282 tons	24-hour rolling average, excluding SU/SD 1 hour period including SU/SD 12-month rolling average including SU/SD
Nitrogen Oxides (NO_x)	Diluent Injection System	15 ppm 15 ppm	30-day rolling average excluding SU/SD 12-month rolling average including SU/SD
Particulate Matter (PM)	Good Combustion Practices, Syngas Fuel	0.011 lb/MBtu, Including SU/SD	Stack Testing , based on a 3-hour block average limit.
Particulate matter < 10 microns (PM_{10})	Good Combustion Practices, Syngas Fuel	0.011 lb/MBtu, Including SU/SD	Stack Testing , based on a 3-hour block average limit.
Sulfur Dioxide (SO_2)	IGCC Process Gas Cleanup System	0.030 lb/MBtu 40 ppm sulfur in syngas 278 tons	24-day rolling average including SU/SD 12-month rolling average including SU/SD
Volatile Organic Compounds (VOC)	Good Combustion Practices	0.0017 lb/MBtu 3.64 lbs 16.93 tons	24-hour rolling average, excluding SU/SD 24-day rolling average excluding SU/SD 12-month rolling average including SU/SD
Lead (Pb)	Good Combustion Practices	0.0000257 lb/MBtu	Stack Test, based on a 3-hour block average limit.
Mercury (Hg)	IGCC Process Gas Cleanup System	0.56 lb/Tbtu 95% Removal	12-month rolling average including SU/SD Stack Testing Coal Sampling & Analysis
Sulfuric Acid Mist (H_2SO_4)	IGCC Process Gas Cleanup System	0.0005 lb/MBtu	Based on a 3-hour rolling average including SU/SD Stack Testing

Control Technologies and Emission Limits for Each Sulfuric Acid Plant

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT	Averaging Time
Sulfur Dioxide (SO_2)	Dual Absorption with mist eliminators	4.0 lbs per ton of Sulfuric Acid Produced	Stack Testing
Sulfuric Acid Mist (H_2SO_4)	Dual Absorption with mist eliminators	0.128 lbs per ton of Sulfuric Acid Produced	Stack Testing
Visible Emissions		10%	Method 9

Control Technologies and Emission Limits for Gasifier Flare

POLLUTANT	CONTROL TECHNOLOGY	EMISSION LIMIT	Averaging Time
Particulate Matter (PM/PM_{10})	Good Flare Design	35 lb/MBtu SU/SD	12-month rolling average
Visible Emissions		0% NTE 5 minutes during any 2 hr period	Method 9

CASE STUDY #1

Attachment 3 –Generation Planning Alternatives
ERGS CPCN Docket, Exhibit JEK-1, Table 1-8 (excerpts)

Generic Units	Size (MW)	Overnight Construction Cost (2003 $/kW)	Var. O&M ($/MWh)	Fixed O&M ($/kW-yr)	Average Heat Rate (Btu/kWh)
Biomass	100	$1,804	$3.13	$48.49	8,911
Coal (bituminous)	515	$1,400	$2.07	$20.90	8,700
NGCC	545	$545	$2.35	$4.28	6,983
Combustion Turbine	150	$400	$2.02	$5.21	10,555
Wind	200	$0 (confidential)			
IGCC	500	$1,437	$0.85	$34.75	8,300

Notes:
1- A firm gas transport charge is assigned to combined cycle units at a rate of $3.45 per kilowatt of capacity, and to combustion turbine units at a rate of $6.08 per kilowatt of capacity.
2- Wind is given no capacity credit toward reserves.
3- A $2.09 / MWh charge is added to wind generation to cover costs of additional spinning reserve margin due to wind resource variability (per Electrotek study).

CASE STUDY #2
Springerville Units 3 and 4
Springerville, Arizona
Tucson Electric Power

Tucson Electric Power is adding two 400 MW coal-based units to its existing two-unit (800 MW) Springerville plant. The units will be equipped with SCR for NO_x control, spray dryers for SO_2 control and baghouses for particulate control. The power will be used to serve the growing electric load in the southwest. Air permitting was conducted in the spring of 2001 and a permit application was filed with the Arizona Department of Environmental Quality in March of the same year.

Tucson Electric Power is adding two 400 MW coal-based units to its existing two-unit (800 MW) Springerville plant.

The air permitting identified two concerns. First, the proposed plant is close to two nearby Class I air quality areas (Petrified Forest National Park and the Mt. Baldly Wilderness Area). To reduce potential impacts on these areas, Tucson Electric agreed to net the SO_2 and NO_x emissions from Springerville Units 1 and 2 to offset new emissions from operating Units 3 and 4. This resulted in a PSD permit being applied for only PM_{10} and the other non-sulfur PSD pollutants. On this basis, long-range transport modeling of the plant's impact on the Class I areas showed no concerns.

The second concern was a legacy issue related to EPA's original permitting of Units 1 and 2. Because construction of Unit 2 began long after its original PSD permit was issued, EPA required a revised best available control technology analysis be done; and the analysis resulted in more stringent controls on Unit 2. After months of negotiations, EPA, Arizona DEQ and Tucson Electric Power agreed to lower the SO_2

and NO_x effective emission rates for Unit 2. These emission reductions enabled the netted emissions from all four units to comply with PSD regulations and the permit was issued.

Litigation brought by a conservation organization raised essentially these same issues by challenging the original issuance of an air permit for Unit 2. A court has decided the litigation in favor of Tucson Electric.

The air permit was issued by the Arizona DEQ and approved by EPA. Unit 3 has been purchased by Tri-State Generation and Transmission Association of Denver and is now under construction. Construction has not yet begun on Unit 4.

CASE STUDY #3
Intermountain Power Project Unit 3
Delta, Utah,
Intermountain Power Agency

Intermountain Power Agency is adding a 950MW coal plant to its Intermountain Power Project.

Intermountain Power Agency is adding a 950 MW coal-based unit to its existing Intermountain Power Project, which has two other 950 MW units. Unit 3 will be equipped with SCR for NO_x control, a FF for particulate control and wet limestone FGD systems for SO_2 control. The power will be used by customers of Los Angeles Department of Water and Power in California and Utah Associated Municipal Power Systems.

The air permit application was submitted to the Utah Division of Air Quality (UDAQ) in December 2002. Several analyses have been performed to determine the impact of the plant on five nearby Class I areas in southern and eastern Utah as well as a non-attainment area in Utah County at Provo. The Class I area analyses were conducted pursuant to the federal land manager guidance (FLAG) document. The result is a demonstration of no significant impact. In addition, a cumulative SO_2 increment consumption analysis was conducted showing that the Class I increment has only been one third consumed in the nearby national parks. A draft permit has been prepared and is being readied for public comment by UDAQ. A public hearing will be held this spring with the final permit issuance to follow this summer.

CASE STUDY #4
Marion Station Units 1-3
Southern Illinois Power Cooperative

SIPC repowered three 33 MW units with a CFB boiler.

Southern Illinois Power Cooperative (SIPC) is a generation and transmission cooperative serving three distribution cooperatives. Organized in 1948, SIPC operates four units at the Marion Station, with the most recent addition being the 173 MW Unit 4 placed in service in 1978. Units 1-3 were commissioned in 1963 and are rated at 33 MW each. All of SIPC's units burn high-sulfur coal and coal mining wastes mined locally in southern Illinois.

Reduced reliability on the three small units and the requirement for costly NO_x emission reductions from these cyclone boilers led SIPC to investigate the most cost-effective and environmentally acceptable approach to meeting the current and future power needs of their member cooperatives. Refurbishment of the existing boilers to improve reliability would have required major modifications and/or replacements to virtually all major components of the plant, including: cyclones, furnace walls, superheater, draft system, boiler feed water pumps, coal conveyors, water treatment, and controls. On top of these major improvements to the steam generator, SIPC would also need to add costly SCR system(s) to reduce NO_x emissions.

These staggering capital requirements with no significant increase in capacity led SIPC to investigate 29 different alternatives, including refurbishment of the existing facilities, a variety of coal- and gas-based technologies, as well as power purchase agreements. Considering a 30-year evaluation period, the most favorable alternative for the SIPC's member cooperatives was a four-fold approach:

1. Retirement of the three steam generators on Units 1-3;
2. Repowering of Units 1-3 steam turbines with a single CFB boiler;
3. Adding SCR for NO_x control on Unit 4; and
4. Adding various gas-fired peaking combustion tubines (CTs).

The heart of the SIPC program is the coal-based CFB repowering of Units 1-3. This coal-based repowering provided SIPC with a 22% increase in capacity over the existing output from the three units. The repowering also led to a 12% increase in the plant's energy conversion efficiency and a related 12% reduction in CO_2 emissions per MWhr of generation.

Air permitting for the proposed Marion Station modifications and additions used the PSD emission "netting" process, which considered both emission reductsions (e.g. retired cyclone boilers, SCR system for NO_x control) and emission additions (e.g. CFB boiler, two CTs). The result was a significant net decrease in NO_x, SO_2, and H_2SO_4 emissions and only minor (well below the PSD threshold for major modifications) increases in other emissions (i.e. VOC, TSP, PM_{10} and lead) with the exception of CO. The net increase in CO emissions exceeded the PSD threshold, and CO therefore was subject to a BACT analysis and (PSD) emission modeling.

This successful project was placed in service in 2003 with significant benefits to SIPC's member cooperatives, the local communities of Southern Illinois and the air shed of the region. This SIPC program has facilitated the continued use of local high sulfur coals and coal mining wastes to more efficiently increase the production of electricity while significantly reducing air emissions.

CASE STUDY #5
Council Bluffs Energy Center Unit 4
Council Bluffs, Iowa
MidAmerican Energy

Council Bluffs Energy Center Unit 4 is a 750 MW SC PC unit being added to an existing MidAmerican Energy facility in Council Bluffs, Iowa. The power will be used in the MidAmerican system.

Air permitting for this facility was relatively straight forward and the review of the permit application by the Iowa Bureau of Air Quality was completed in nine months. The closest Class I area to this plant is in southern Missouri (about 600 km away). Some concern was expressed about current air quality levels for PM_{10} and SO_2 in the area, but no public comments were offered on the draft permit and the permit was issued. The unit is under construction. Pre-operation air quality data are being collected.

CASE STUDY #6

Hunter Unit 4
Castle Dale, Utah
PacifiCorp

Hunter Unit 4 is a 550 MW coal-based unit being added to the existing Hunter Power Plant in Castle Dale, Utah, and is owned by PacifiCorp. The power generated by Unit 4 will be used in the PacifiCorp system. PacifiCorp has chosen to reduce the SO_2 and NO_x levels from Hunter's existing Units 1, 2, and 3 to offset the new emissions from Unit 4. The netting of SO_2 and NOx across the plant resulted in a PSD permit being applied for PM_{10} and other non-SO_2 PSD emissions. Air quality data analysis from nearby Class I areas has shown no significant impact from the proposed unit. The permit application is currently being reviewed by UDAQ.

CASE STUDY #7
Comanche Unit 3
Pueblo, Colorado
Xcel Energy
or
Pawnee Unit 2
Brush, Colorado
Xcel Energy

Xcel Energy is planning to build a new 750 MW SC PC unit at either its Comanche Plant in Pueblo, Colorado, or its Pawnee Plant in Brush, Colorado. Regardless of the site, this unit will be added to an existing facility. The power will be used in the Xcel system. Xcel is currently evaluating both sites and will select one for the construction of the new unit. Preparation of the permit application has not yet begun.

CASE STUDY #8
New Plant
NE Iowa
Dairyland Power

Dairyland Power is planning to construct a new 400 MW coal-based unit in northeast Iowa. A site selection study has located two sites that are being evaluated for the plant. The EIS process has been initiated for this project, but the preparation of the air quality permit application has not yet begun.

Conclusion

These case studies provide an indication of the uncertainties and difficulties encountered in the development of new coal-based plants. The significant common theme is that even after the decision is made to build a new plant, significant risks emerge during the complicated regulatory and permitting processes. Figure 5.1 provides a summary of the significant aspects of each of the eight case studies reviewed.

FIGURE 6.2
Case Studies Summary Table (Units Added at Existing Plants)

Power Plant (plant, utility, location)	**Configuration** (power output, fuel type, steam conditions, AQS, emission requirements)	**Key Project Dates** (initial announcement, permits, construction, commercial operation)	**Issues During Project Development**	**Status & Remaining Actions**
Council Bluffs Energy Center – Unit 4 MidAmerican Energy Council Bluffs, Iowa	790 MW; PRB Coal SC PC, SCR + SDA + Baghouse NO_X 0.07 lb/MBtu SO_X 0.1 lb/MBtu PM_{10} 0.025 lb/MBtu Hg $1.7x10^{-6}$ lb/MBtu	Site announced: 1/02 AQ Permit issued: Construction started: 9/03 Commercial op: mid-2007	SO_2; PM_{10}	Pre-operational AQ data being collected. Regulatory approval needed for transmission line upgrade.
ERGS, Elm Road Adj. To Oak Creek Plant Milwaukee, Wisconsin	2 units; 615 MW each; SC PC	Proposed: 2000 CPCN filed: 2/02 Approved: 11/02 EIS: 9/02 Air permit: 1/04 Construction: 2nd half '04 In-service (Unit 1): 5/09 In-service (Unit 2): 5/10	600 MW IGCC denied; System-wide reduction: NOX, SOX >65%; Hg 50%; Wetlands permit in progress	100% use of coal combustion products by WeEnergy; NPV advantage: Coal $1.9 B over Gas; Additional controls: CO; Pb; PM_{10}; VOC; F; HCl; H_2SO_4
Springville Units 3 & 4 Tucson Electric Power Tucson, Arizona	2 units; 400 MW each; Coal-based	Unit 3 in construction; Unit 4 not yet started	Proximity to Class 1 AQ areas; Revised BACT for No. 2 SCR, PM_{10}, NO_x, SO_x,	PSD permit for PM_{10} & Non-S pollutants. Reduce NO_X, SO_X on Units 1 & 2. Court ruling in favor of company.
Intermountain Project, Unit 3 Intermountain Power Agency Delta, Utah	950 MW; Coal-based	Draft permit for public comments; Air permit applied 12/02; Draft permit in preparation	Class 1 & non-attainment; no significant impact.	SO_X increment 1/3 consumed. LADWP customer. Permit expected by Summer '04

CASE STUDIES SUMMARY CHART
(Units Added at Existing Plants)
Continued

Power Plant (plant, utility, location)	**Configuration** (power output, fuel type, steam conditions, AQS, emission requirements)	**Key Project Dates** (initial announcement, permits, construction, commercial operation)	**Issues During Project Development**	**Status & Remaining Actions**
Hunter, Unit 4 PacifiCorp Castle Dale, Utah	550 MW Coal-based; added to existing 1,2 & 3; NO_X, SO_X from 1,2 & 3 to offset Unit 4 emissions		Impact on Class 1 Areas; PSD in process for PM_{10}, non-S PSD emissions	PSD Permit being applied for PM_{10} & Non S PSD Pollutants
Comanche, Unit 3 or Pawnee Unit 2 Xcel Energy Pueblo or Brush, Colorado	750 MW; SC PC	Site selection initiated; AQ permit preparation to start		USER Xcel Energy. Selection of one site to be made soon.
New Plant in Notheast Iowa Dairyland Power NE Iowa	400 MW; Coal-based	2 sites being evaluated	Environmental Impact Study started; AQ permit not yet started	Prepare AQ permit. Complete site selection.
Marion Station Units 1-3 Southern Illinois Power Cooperative Southern Illinois	Repower existing units; coal-based CFB; 22% power increase; 12% efficiency increase; 12% CO_2 reduction	Repowering started: 2003	Decreases in NO_X, SO_X; minor increases in VOM, TSP, PM_{10}, Pb	Continued use of local high-sulfur coal. CO subject to BACT.

Section 7: Opportunities for the Future of Coal in the National Energy Mix

<u>Historical Perspective</u>
(1985 – 2003)

Only 52 GW of new plants came on line from 1985 to 2003.

The historical and projected capacity additions for electricity in the U.S. from 1985 to 2003 effectively depict the condition of the power industry during that period. From 1985 to 1998, the range of capacity additions per year varied from 1,600 MW to 7,900 MW, with an average of about 4,000 MW. This growth pattern of approximately 0.5%/yr (of a total 800,000 MW installed capacity) was significantly less than the increase in the electrical demand during the same period. Reserve margins across the U.S. dramatically dropped below the industry-wide standard of 15%.

The effect of these significant reductions in the reserve margins, along with the introduction of deregulation, spurred the most significant capacity expansion in the history of the U.S. In 1999, almost 9,000 MW of new capacity came on line – most of these were simple-cycle gas turbines burning natural gas, providing peaking capacity. It wasn't rocket science. Simple cycle plants were quick and easy to install, with low capital cost, negligible environmental impacts and gas prices less than $3.0/MBtu. New independent power producers and merchant plants led the way. Moreover, the financial institutions were more than happy to finance the boom. Coal-based generation was not designed to provide this component (peaking) of the overall need for additional generation. In addition, coal was perceived to be at a disadvantage from an environmental standpoint when compared to natural gas. This perception found its way into the policies and positions of some regulatory agencies.

36GW of new plants came on line in 1999 and 2000. Most of that capacity was fueled by natural gas.

In 2000, nearly 27,000 MW of new capacity came on-line, including both gas-fired simple-cycle (peaking) and NGCC (baseload) units. With low-cost natural gas available, and NGCC installed costs of $500-600/kW, they were the choice for baseload capacity. However, for future baseload capacity, new coal-based plants were being considered (24 coal-based facilities were announced according to the 2001 *Power Plant Construction Magazine*) most notably because of a significant increase in gas prices during that specific period of time.

At the peak of power plant development, over 300,000 MW of new generation was announced, planned or in construction. The net result was the projected addition of 5%/yr of new generating capacity. EIA had projected a range of 2.3-3.6% increases in electrical demand for 2001. Thus, about 50% of the new capacity being built at that time addressed increase in demand while the other 50% addressed the need for enhanced reserve margins. Such projections were consistent with Vice President Cheney's Energy Task Force that recommended that 1,300-1,800 new power plants be built during a 20-year period.

Some analysts, including Salomon-Smith Barney considered these projections overly optimistic and predicted that as many as 50% of the projects would never be constructed. However, the main reason for this pessimism was not the obvious as we understand today but rather the concern of inadequate supply of natural gas, the fuel for at least 95% of these new projects.

Beginning in late 2000 and continuing into 2001 and 2002, several major events changed the future of this historical growth pattern. First, gas prices significantly increased (>160%). Second, the recession set in and the annual demand electricity forecasts began to fall off. Third, significant financial problems occurred at most of the major IPPs and merchant energy companies, resulting in financial institutions cutting off funding to power plant developers. Fourth, questionable market practices by some merchant and trading companies lead to their being forced out of the marketplace. While the extent of such practices can be debated, the public perception that IPPs were responsible for increased prices and shortages in areas such as California was very real. This further exacerbated the financial problems and led to many states retracting their moves towards deregulation. This removed an incentive from the marketplace. The overall impact of these factors was that new plant construction was significantly curtailed, especially for the most capital intensive projects, which at that time (2002) meant most of the newly announced coal-based plants.

Market changes and high natural gas prices have curtailed the construction of new plants since 2002.

Because of high natural gas prices, *EIA Annual Energy Outlook (AEO) 2004* continued to forecast significant new coal-based generation, although most are noted as "Unplanned." Approximately 52,000 MW were forecast in the 2004 report.

- **2000-2005:** 0 MW
- **2006-2010:** 6,800 MW
- **2011-2015:** 11,800 MW
- **2015-2020:** 33,200 MW

In its June 2003 issue, *Power Magazine* was more bullish, predicting 11,500 MW of new coal-based capacity by 2007. (This is only a quarter of what was originally announced.)

Overall, most of the coal-based capacity announced in the 2000-2002 timeframe will not be built. While the need for additional generation may still exist, the demise of many IPPs and the lack of funding make these projects highly unlikely. For the future, the need will be there and the competitive advantage of coal prices compared with higher gas prices will exist, but the capital cost of coal-based generation will continue to be problematic, not just for regulated utilities, but especially for IPPs and merchant plant developers.

Longer Term Opportunities
(2004-2025)

The major long-term opportunities/challenges for coal are: (1) price stability, (2) cost competitiveness, (3) environmental controls and (4) energy security.

Planning for coal-based plants must address price stability, cost competitiveness, environmental controls and energy security.

Price Stability. EIA's *AEO 2004* report projects fuel prices (2002 $/MBtu) delivered to electricity generators for natural gas, oil, coal and nuclear. Coal prices are expected to be stable during this entire 20+ year period at $1.25/MBtu. Gas prices are projected to drop to $4.00/MBtu in 2004 and then gradually increase to $4.75/MBtu by 2025. However, natural gas price forecasts vary considerably depending on trends in domestic exploration and production, as well as the future role of imports of LNG.

Cost Competitiveness. DOE report #DE-AC-01-94FE62747, April 2001, projected marginal competitive pricing for gas- and coal-based power plants. In this study, an NGCC power plant with a capital cost of $500-600/kW and a gas price of $3.50/MBtu was basically equivalent to a coal-based plant with a capital cost of $1,000-1,200/kW and a fuel cost of $1.00-1.25/MBtu. With everything else being equal, an equivalent natural gas price of $4.50/MBtu would amount to increasing the cost of electricity for an NGCC plant by about 25%.

In the most recent National Coal Council report, *Increasing Coal-Fired Generation Through 2010: Challenges and Opportunities, May 2002*, costs were presented for advanced combustion technologies by 2010. This study showed that NGCC technology with an "H" model gas turbine would cost $460/kW, somewhat negating the effect of the higher gas cost. Advanced supercritical PC and Advanced IGCC (air or oxygen blown) units could be installed for essentially $1,000/kW, the lower range of the price quoted above.

From a cost competitiveness position, coal is expected to be able to maintain an advantage over gas for both the short and long term.

Environmental Controls. Perception and reality concerning environmental issues for coal-based power plants are still major concerns for the power industry. The following are facts, not myths.

- According to the latest findings on national air quality published in *2002 Status and USEPA Trends*, emissions of the six principal air pollutants have been cut 48% since 1970, despite a 42% increase in energy consumption;
  - SO_2 emissions are 41% lower than in 1980
  - Power plant NO_x emissions are 33% lower than in 1990

- The Annapolis Center for Science-Based Public Policy has found that since the 1960s, ambient concentrations of SO_2 have dropped by over 90% and concentrations of NO_x have dropped by more than half. (*A Critique of the Campaign Against Coal-Fired Power Plants, 2002*)

- EPA and Department of Energy data show that between 1970 and 1999 CO, VOC, PM_{10} and lead levels in the environment decreased 28%, 42%, 75% and 98% respectively.

- The popular impression that older coal plants are "grandfathered," which many interpret to being uncontrolled, is fiction –
  - Every power plant is regulated under the NAAQS and the acid rain Title IV programs for SO_2 and NO_x; many are regulated under the NO_x SIP call for eastern state ozone.

- Utilities that are currently installing SO_2 controls (i.e., TVA, Duke, Progress Energy, Cinergy, AEP and Southern Company) are requiring more stringent SO_2 control than would be required by NSPS. In other words, existing plants would be as clean (or cleaner) than new plants.

In addition, new/proposed regulations for existing coal-based plants would reduce emissions even further.

- Clear Skies and/or the Interstate Air Quality Rule (IAQR) would double the amount of FGD systems installed in the U.S. by 2010. SO_2 emissions would be cut by 70% beyond current levels of emissions.
- Clear Skies legislation would double the amount of SCR capacity in the U.S. The IAQR would increase SCR capacity by 50% in 2010 with continued growth in SCR thereafter.
- Significant amounts of mercury would be captured with the addition of FGD and SCR systems. The IAQR would reduce power plant mercury emissions to 15 tons in 2018 (a 70% reduction from current levels).

The result of these rules and regulations would make existing coal-based plants cleaner than at any time in our nation's history. In many instances, there would be basically no difference in environmental emissions from a new plant versus an existing coal-based plant.

Energy Security. Coal remains an affordable and reliable domestic energy source. As such, coal was recognized as an essential component of our domestic energy supply in the May 2001 *National Energy Policy*. Coal reserves, which are distributed geographically throughout the U.S., comprise the greatest share of the nation's energy resource base. Of the nation's more than 500 billion tons of demonstrated coal reserves, 275 billion tons are economically recoverable using existing technologies. The U.S. has sufficient coal reserves to meet growing demand for well over 200 years, according to *National Energy Security Post 9/11*.

America already relies heavily on domestic coal to meet its energy needs. Coal accounts for approximately one-third of the nation's primary energy production and for about 23% of U.S. energy consumption. Coal is principally used to generate electricity; over 50% of power generated in the U.S. comes from coal-based power plants. According to EIA's *Annual Energy Outlook 2002*, coal production is expected to increase by some 200 million tons, or by just over 19%, by the end of the next decade. In 2010, production is forecast to reach 1.284 billion tons. This entire increase will be used to generate electricity, but coal's share of total electrical generation will decline slightly from its current share of 51%.

Unlike some forms of energy, coal poses few security issues during the production, distribution or storage stages. Nearly all the coal used in the U.S. (99%) is mined domestically and shipped by either rail or through our inland waterway system to power plants, steel mills, cement processing facilities and other industrial users. Because coal is a solid, it poses little risk to the surrounding public and would not likely be a target for terrorists. In the event of an emergency, the coal industry could increase production fairly quickly to meet increased demand for fuel for electricity and would only be hampered by possible transportation constraints.

Conclusion

Despite the market fundamentals over the past 20 years that have led to an onslaught of natural gas-fired plants, coal remains the fuel of choice to provide a stable and secure source of energy for the nation. The major long-term opportunities/challenges for coal – price stability, cost competitiveness, environmental controls and energy security – must be recognized and understood in order to address the importance of coal to the economy.

Section 8: Conclusions

During the past decade, the availability of low-cost natural gas and increasing deregulation essentially halted the construction of coal-based power plants. However, the rapid deployment of NGCC plants, coupled with more rapid depletion of existing natural gas basins, caused demand for natural gas to significantly exceed supply. The result was overcapacity of electric power generation in a number of markets, a significant and sustained increase in the market price and price volatility of natural gas and very low capacity factors for NGCC plants (average of 29% for 2003). This has let to the return to coal as a favored feedstock for power generation.

A significant impediment to the construction of new coal-based power plants is that the total cost of a new plant must compete in an open marketplace with the cost of electricity from existing power plants.

But even though coal is now favored for power generation, market overcapacity has created impediments to new construction. A significant impediment to the construction of new coal-based power plants is that the total cost of a new plant (which includes capital recovery, fuel and operating costs) must compete in an open marketplace with the cost of electricity from existing power plants, where the capital cost is no longer a significant portion of the cost of electricity. The lower COE from existing plants usually results in the lowest overall electric price to the customers, but it creates a significant economic hurdle to the construction of new coal-based power plants.

Further, the regulatory system which has led to the retrofit of expensive emission control systems onto existing plants, coupled with the uncertainty of recovery of capital investment due to the structural changes in the electricity sector are underlying obstacles to wide-spread construction of new coal-based power plants. The uncertainty of future environmental regulations also complicates the decision between retrofitting existing older coal-based plants or retiring them and constructing new coal-based plants.

As discussed in Section 3, numerous incentives to facilitate the construction of new advanced coal-based power plants either exist or have been proposed. While past incentives, based primarily on demonstration of new advanced technologies, have facilitated the construction of some new coal-based power plants, they have proved inadequate to attract investment in a significant number of new plants. This report has examined in considerable detail the structural issues that have inhibited the construction of new plants and offer recommendations that should help drive commercial-scale deployment and market penetration of new advanced clean coal power plants.

Incentives are required to enable the life-cycle cost of a new advanced coal-based power plant to be economically neutral to the investor vis-à-vis alternative conventional technologies.

The National Coal Council recommends that the Department of Energy develop federal incentives to reduce the risk-adjusted cost of new advanced coal-based plants that are not competitive with alternative technologies. The Council has not taken a position on which incentives (i.e., capital cost sharing, production tax credits, accelerated depreciation) would be most effective. The important issue is that whatever incentives are provided must enable the life-cycle cost of a new advanced coal-based power plant to be economically neutral to the investor, vis-à-vis alternative conventional technologies. A key outcome of the incentives should be to encourage deployment of multiple new commercial-scale advanced coal-based plants that are based on relatively proven designs. Special emphasis should be provided to promote those advanced clean coal technologies that best support Department of Energy and Administration goals of moving toward near-zero emissions power plants, a hydrogen-based energy economy, and carbon sequestration.

Tying those incentives to the retirement of older, less efficient power plants in such a way that the owners of the existing facilities are able to recover the difference between the incremental cost of generating electricity at the existing facility and the new facility (i.e., recovery of the new capital investment and any stranded capital from the retirement of the older facility). Improved financial and regulatory models are also needed to appropriately account for and assess the overall risks and life-cycle costs associated with keeping and retrofitting older facilities versus retiring them and constructing new advanced coal-based plants.

A clear regulatory mechanism is also needed that will allow the investor to recover the added costs of the new facility though charges in the electricity marketplace. Because the benefit of new coal-based generation is on a national level, and the environmental benefits of advanced coal-based generation are on both regional and national levels, this regulatory mechanism for rate recovery must transcend state borders. Therefore, mechanisms are needed that will allow the recovery of the capital investment of the plants through capacity charges on a regional basis such as geographic coal basins or regional transmission organizations. The federal government must also work with state PUCs to ensure that utilities are able to recover those capacity charges through electricity rates.

A clear regulatory mechanism is needed that will allow the investor to recover the added costs of the new facility though charges in the electric marketplace.

Incentives should recognize and reward IGCC's potential to replace the use of natural gas in multiple markets – power, chemicals, fuels and fertilizers. Incentives should treat poly-generation options favorably and special incentives should be developed for repowering of distressed natural gas combined cycle plants with coal-based syngas.

As discussed in Section 6, there is a need for an environmental regulatory approach that provides more certainty to the investor in coal-based power plants and eliminate several of the roadblocks to an expeditious permitting process that have arisen over the years

There is a need for an environmental regulatory approach that provides more certainty to the investor in order to eliminate several of the roadblocks to an expeditious permitting process.

Because of the rapid increase in natural gas prices and the view that gas prices may remain at these levels in the long term, many operating and partially constructed NGCC plants have become distressed assets that are not being dispatched. As a means of preserving the asset value in these plants, initial assessments indicate that it may be economical to convert some of these natural gas plants to coal-based plants using IGCC. The syngas produced by coal gasification can be combusted in these gas turbines with minor modifications. It may also be possible to build one or more coal gasification facilities to feed a closely clustered group of NGCC plants. Many factors must be considered including the need for power, access to coal transportation, plant location, etc. It is recommended that a program be implemented to address IGCC repowering of distressed NGCC plants. This would involve performing a detailed assessment of the economics of repowering, prioritizing and categorizing NGCC assets and devising an incentive program to initiate the conversion process.

Continued public education is also essential to strongly reinforce that coal is a vital resource for our country, that it must be utilized to provide an adequate measure of energy security and reliability, that it has been and will continue to be the major fuel for electricity generation in the country, that it should be encouraged as an alternative feedstock for chemicals and fuels, that appropriate incentives and regulatory approaches should be provided to encourage its use in as clean a manner as possible, and that the use of such

Coal is a vital national resource, provides energy security, and has been and will continue to be used for electric power generation.

clean coal technologies should be fostered, encouraged and promoted in other countries where coal is a vital resource.

It is critical that the coal producers, transporters, users, equipment suppliers and users, the federal government and the state regulatory agencies recognize the strategic importance of clean coal technologies to the United States and the world, and cooperate to ensure that advanced coal-based plants are constructed in the near term.

APPENDIX A

Description of The National Coal Council

In the fall of 1984, The National Coal Council was chartered and in April 1985, the Council became fully operational. This action was based on the conviction that such an industry advisory council could make a vital contribution to America's energy security by providing information that could help shape policies relative to the use of coal in an environmentally sound manner which could, in turn, lead to decreased dependence on other, less abundant, more costly, and less secure sources of energy.

The Council is chartered by the Secretary of Energy under the Federal Advisory Committee Act. The purpose of The National Coal Council is solely to advise, inform, and make recommendations to the Secretary of Energy with respect to any matter relating to coal or the coal industry that he may request.

Members of The National Coal Council are appointed by the Secretary of Energy and represent all segments of coal interests and geographical disbursement. The National Coal Council is headed by a Chairman and Vice-Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members. To wit, it receives no funds whatsoever from the Federal Government. In reality, by conducting studies at no cost, which might otherwise have to be done by the Department, it saves money for the government.

The National Coal Council does not engage in any of the usual trade association activities. It specifically does not engage in lobbying efforts. The Council does not represent any one segment of the coal or coal-related industry nor the views or any one particular part of the country. It is instead to be a broad, objective advisory group whose approach is national in scope.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the requested study. The first major studies undertaken by The National Coal Council at the request of the Secretary of Energy were presented to the Secretary in the summer of 1986, barely one year after the start-up of the Council.

APPENDIX B

The National Coal Council 2004 Member Roster

Robert O. Agbede, President & CEO
ATS Chester Engineers
639 Alpha Drive
Pittsburgh, PA 15238
Ph: 412-967-1900 Ext. 203
ragbede@atschester.com

James R. Aldrich, State Director
The Nature Conservancy
642 West Main Street
Lexington, KY 40508
Ph: 606-259-9655
Fx: 606-259-9678
jaldrich@tnc.org

Allen B. Alexander, President & CEO
Savage Companies
6340 South 3000 East #600
Salt Lake City, UT 84121
Ph: 801-944-6600
Fx: 801-261-8766
AllenA@SavageCompanies.com

Sy Ali, President
Clean Energy Consulting Corp.
7971 Black Oak Drive
Plainfield, IN 46168
Ph: 317-839-6617
Syali1225@aol.com

Barbara Farmer-Altizer, Executive Director
Eastern Coal Council
P.O. Box 858
Richlands, VA 24641
Ph: 276-964-6363
Fx: 276-964-6342
barb@netscope.net

Gerard Anderson, President & COO
DTE Energy Company
2000 2nd Avenue, 2409 WCB
Detroit, MI 48226-1279
Ph: 313-235-8880
Fx: 313-235-0537
andersong@dteenergy.com

Dan E. Arvizu, Ph.D.
Sr Vice President & CTO
Energy, Environment & Systems Businesses
CH2M Hill
9191 South Jamaica Street
Englewood, CO 80112
Ph: 720-286-2436
Fx: 720-286-9214
darvizu@ch2m.com

Kathie A. Baardson
CEO & Managing Member
Nordic Energy, LLC
9013 NE Highway 99, Suite S
Vancouver, WA 98665

Richard Bajura, Director
National Research Center for Coal & Energy
West Virginia University
P.O. Box 6064, Evansdale Dr.
Morgantown, WV 26506-6064
Ph: 304-293-2867 (ext. 5401)
Fx: 304-293-3749
bajura@wvu.edu

Janos M. Beer
Professor of Chemical & Fuel Engineering
Dept. of Chemical Engineering
Massachusetts Institute of Technology
25 Ames St., Bldg. 66-548
Cambridge, MA 02139
Ph: 617-253-6661
Fx: 617-258-5766
jmbeer@mit.edu

Richard Benson, President
Caterpillar Global Mining
300 Hamilton Blvd., Ste. 300
Peoria, IL 61629-3810
Ph: 309-675-5127
Fx: 309-675-4777
Benson_Richard_a@cat.com

Jacqueline F. Bird, Director
OH Coal Development Office
OH Air Quality Development Authority
50 W. Broad St., Suite 1718
Columbus, OH 43215
Ph: 614-466-3465
Fx: 614-752-9188
jbird@aqda.state.oh.us
www.ohioairquality.org

Sandy Blackstone
Natural Resources Attorney/Economist
8122 North Sundown Trail
Parker, CO 80134
Ph: 303-805-3717
Fx: 303-805-4342
sblackstone@ssbg.net

Robert L. Brubaker, Partner
Porter, Wright, Morris & Arthur
41 South High St.
Columbus, OH 43215
Ph: 614-227-2033
Fx: 614-227-2100
rbrubaker@porterwright.com

Michael Carey, President
Ohio Coal Association
17 S. High Street, Suite 215
Columbus, OH 43215-3413
Ph: 614-228-6336
Fx: 614-228-6349
info@ohiocoal.com
www.ohiocoal.com

Henry J. Cialone, Sr. Vice President
& General Manager/Energy Products
Battelle Labs
4606 Burbank Drive
Columbus, OH 43220
Ph: 614-457-7948
cialoneh@battelle.org

William Connors, Esquire
Centennial Power, Inc.
400 North 4th Street
Bismarck, ND 58501
Ph: 701-222-7965
Cell: 701-426-2913
Fx: 701-222-7877
bill.connors@mduresources
www.centennialenergy.com
www.mduresources.com

Steve Corwell
Sr. Vice President, Corporate Affairs
Indianapolis Power & Light
One Monument Circle
Indianapolis, IN 46204
Ph: 317-261-8240
Steve.corwell@aes.com

Kelly A. Cosgrove
Vice President, Marketing & Sales
Kennecott Energy Company
PO Box 3009
505 South Gillette Avenue
Gillette, WY 82716
Ph: 307-687-6053
Fx: 307-687-6009
cosgrovk@kenergy.com

Henry A. Courtright, Vice President
Power Generation & Distributed Resources
Electric Power Research Institute
3412 Hillview Ave.
Palo Alto, CA 94304
Ph: 650-855-8757
Fx: 650-855-8500
hcourtri@epri.com

Joseph W. Craft, III, President
Alliance Coal
1717 S. Boulder Ave.
Tulsa, OK 74119
Ph: 981-295-7602
Fx: 981-295-7361
josephc@arlp.com

E. Linn Draper, Jr.
Chairman, President & CEO
American Electric Power Company
One Riverside Plaza
Columbus, OH 43215
Ph: 614-223-1500
Fx: 614-223-1599
eldraper@aep.com

Michael D. Durham, President
ADA Environmental Solutions
8100 SouthPark Way, Unit B2
Littleton, CO 80120
Ph: 303-737-1727
Fx: 303-734-0330
miked@adaes.com

John Dwyer, President
Lignite Energy Council
1016 E. Owens Ave., Ste. 200
PO Box 2277
Bismarck, ND 58502-2277
Ph: 701-258-7117
Fx: 701-258-2755
jdwyer@lignite.com

Richard W. Eimer, Jr., Sr. Vice President
Dynegy, Inc.
2828 North Monroe St.
Decatur, IL 62526
Ph: 217-876-3932
Fx: 217-876-3913
rich_eimer@dynegy.com

Irl F. Engelhardt, Chairman & CEO
Peabody Energy
701 Market Street
St. Louis, MO 63101
Ph: 314-342-3400
Fx:
Email:

Andrea Bear Field, Partner
Hunton & Williams
1900 K St., NW, 12th Fl.
Washington, DC 20036
Ph: 202-955-1558
Fx: 202-778-2201
afield@hunton.com

Lance Fritz, Vice President &
General Manager/Energy
Union Pacific Railroad
1416 Dodge Street
Omaha, NE 68179
Ph: 402-271-5678
Fx: 402-271-3378
lfritz@up.com

Paul Gatzemeier
Vice President & General Manager
Centennial Energy Resources, LLC
122 East Broadway
Bismarck, ND 58501
Ph: 701-222-7985
Fx: 701-222-7877
paul.gatzemeier@mduresources.com

Janet Gellici, Executive Director
American Coal Council
2890 E. Northern Ave., Ste. B4
Phoenix, AZ 85028
Ph: 602-485-4737
Fx: 602-485-4847
jgellici@americancoalcouncil.org
www.americancoalcouncil.org

Patrick Graney, President
Petroleum Products, Inc.
500 Rivereast Dr.
Belle, WV 25015
Ph: 304-926-3000, ext. 113
Fx: 304-926-3009
pgraney@petroleumproductsinc.com

Alex E. S. Green
Graduate Research Professor Emeritus
University of Florida
Gainesville, FL 32611-6550
Ph: 352-392-2001
Fx: 352-392-2001 (call before sending)
aesgreen@ufl.edu

John Nils Hanson, President & CEO
Joy Global, Inc.
100 E. Wisconsin Ave., Ste. 2780
Milwaukee, WI 53202
Ph: 414-319-8500
Fx: 414-319-8510
jnha@hii.com

Clark D. Harrison, President
CQ, Inc.
160 Quality Ctr. Rd.
Homer City, PA 15748
Ph: 724-479-3503
Fx: 724-479-4181
clarkh@cq-inc.com
www.cq-inc.com

J. Brett Harvey, President & CEO
CONSOL Energy, Inc.
1800 Washington Rd.
Pittsburgh, PA 15241
Ph: 412-854-6671
Fx: 412-854-6613
bretthavey@consolenergy.com

William Hoback, Bureau Chief
Office of Coal Development, State of Illinois
607 East Adams Street, CIPS-4
Springfield, IL 62701
Ph: 217-785-2001
Fx: 217-558-2647
bill_hoback@commerce.state.il.us

Warren J. Hoffman, Esquire
Frost Brown Todd LLC
250 W. Main St., Ste. 2700
Lexington, KY 40507-1749
Ph: 859-244-3320
Fx: 859-231-0011
whoffman@fbtlaw.com

Gerald (Jerry) A. Hollinden
Vice President, Power Sector Manager
URS Corporation
Waterfront Plaza Tower One
325 W. Main St., Ste. 1200
Louisville, KY 40202-4251
Ph: 502-217-1516
Fx: 502-569-3326
jerry_hollinden@urscorp.com

Christopher P. Jenkins
Sr. Vice President, Coal Service Group
CSX Transportation
500 Water Street
Jacksonville, FL 32202
Ph: 904-366-5693
Fx: 904-359-3443
chris_jenkins@csx.com

William Dean Johnson
Executive Vice President, General Counsel and Secretary
Progress Energy, Inc.
411 Fayetteville St. Mall
Raleigh, NC 27602
Ph: 919-546-6463
bill.johnson@pgnmail.com

Judy A. Jones, Commissioner
Public Utilities Commission of OH
180 East Broad St.
Columbus, OH 43215-3793
Ph: 614-644-8226
Fx: 614-466-7366
judy.jones@puc.state.oh.us
www.puc.state.oh.us

Dick Kimbler
PO Box 186
Danville, WV 25053
Ph: 304-369-3347

James R. Klauser
Sr. Vice President
Wisconsin Energy Corporation
231 West Michigan Street
Milwaukee, WI 53203
Ph: 414-221-4740
Fx: 414-221-3550
james.klauser@we-energies.com

Thomas G. Kraemer, Group Vice President
Burlington Northern Santa Fe Railway Co.
2650 Lou Menk Dr.
Ft. Worth, TX 76131-2830
Ph: 817-867-6242
Fx: 817-352-7940
thomas.kraemer@bnsf.com

Max L. Lake, President
Applied Sciences, Inc.
141 W. Xenia Ave, PO Box 579
Cedarville, OH 45314-0579
Ph: 937-766-2020 ext. 111
Fx: 937-766-5886
mllake@apsci.com

Steven F. Leer, President & CEO
Arch Coal Inc.
One City Place, Ste. 300
St. Louis, MO 63141
Ph: 314-994-2900
Fx: 314-994-2919
sleer@archcoal.com

David A. Lester, Executive Director
Council on Energy Resource Tribes
695 S. Colorado Blvd., Ste. 10
Denver, CO 80246-8008
Ph: 303-282-7576
Fx: 303-282-7584
ad@qwest.net

John T. Long, Sr. Vice President
Power Generation
Constellation Energy
111 Market Place, Suite 200
Baltimore, MD 21202
Ph: 410-230-4910
Fx: 410-230-4669
john.long@constellation.com

Jason Makansi, President
Pearl Street, Inc.
801 North Second Street, Suite 403
St. Louis, MO 63102
Ph: 314-621-0403
jmakansi@pearlstreetinc.com

James K. Martin
Vice President, Business Development
Dominion Energy
PO Box 26532
Richmond, VA 23261
Ph: 804-819-2176
Fx: 804-819-2219
james_k_martin@dom.com

Christopher C. Mathewson
Dept. of Geology & Geophysics
Texas A&M University, MS-3115
College Station, TX 77843-3115
Ph: 409-845-2488
Fx: 409-847-9313
mathewson@geo.tamu.edu

Kevin McGowan
(awaiting contact info)

Michael W. McLanahan, President & CEO
McLanahan Corporation
200 Wall Street
Hollidaysburg, PA 16648-0229
Ph: 814-695-9807
Fx: 814-695-6684
mmclanahan@mclanahan.com

Emmanuel R. Merle, President
Energy Trading Company
15 East Putnam Ave., #3210
Greenwich, CT 06830
Ph: 203-618-0161
Fx: 203-618-0454
thion@mindspring.com

Clifford R. Miercort, President & CEO
The North American Coal Corporation
14785 Preston Rd, Ste. 1100
Dallas, TX 75240-7891
Ph: 972-448-5402
Fx: 972-661-9072
clifford.miercort@nacoal.com

Jeffrey Miller, Managing Editor
Definitive Solutions Company, Inc.
8180 Corporate Park Dr., Ste 220
Cincinnati, OH 45242
Ph: 513-719-9150
Cell: 513-678-5456
Fx: 513-719-9130
jeff_miller@dsc-online.com

Michael G. Mueller, Vice President
Ameren Energy Fuels & Services Co.
PO Box 66149, Mail Code 611
St. Louis, MO 63166-6149
Ph: 314-554-4174
Fx: 314-206-1250
mmueller@ameren.com

Robert E. Murray, President & CEO
Murray Energy Corporation
29325 Chagrin Blvd., Ste. 300
Pepper Pike, OH 44122
Ph: 216-765-1240
Fx: 216-765-2654
bobmurray@coalsource.com

Ram G. Narula
Bechtel Fellow & Principal Vice President
Bechtel Power Corporation
5275 Westview Dr.
Frederick , MD 21703
Ph: 301-228-8804
Fx: 301-694-9043
rnarula@bechtel.com

Georgia Ricci Nelson, President
Midwest Generation EME, LLC
440 S. LaSalle St., Ste. 3500
Chicago, IL 60605
Ph: 312-583-6050
Fx: 312-583-4920
gnelson@mwgen.com

Mary Eileen O'Keefe, Director
KFx, Inc.
1362 North State Parkway
Chicago, IL 60610
Ph: 312-482-9701
Fx: 312-482-9703
maryeileenokeefe@aol.com

Umit Ozkan, Associate Dean for Research
College of Engineering & Professor of Chemical Engineering
Ohio State University
167 Hitchcock Hall, 2070 Neil Ave.
Columbus, OH 43210-1275
Ph: 614-292-6623 (Dept)
Ph: 614-292-2986 (College)
Fx: 614-292-9615
ozkan.1@osu.edu
www.che.eng.ohio-state.edu/facultypages/ozkan.html

Daniel F. Packer, President
Entergy New Orleans
PO Box 61000
New Orleans, LA 70161
Ph: 504-670-3622
Fx: 504-670-3605
dpacker@entergy.com

Thomas Pajonas, Managing Director
ALSTOM USA
2000 Day Hill Road
Windsor, CT 06095
Ph: 860-285-5035
Fx: 860-285-5425

Fredrick D. Palmer, Exec. Vice President
Peabody Energy
701 Market St.
St. Louis, MO 63101-1826
Ph: 314-342-7624
Fx: 314-342-7614
fpalmer@peabodyenergy.com

Earl B. Parsons, III, Vice President-Fuels
Southern Company
600 N. 18th St., 14N-8160, PO Box 2641
Birmingham, AL 35291
Ph: 205-257-6100
Fx: 205-257-0334
eabparso@southernco.com

Craig E. Philip, President & CEO
Ingram Barge Company
One Belle Meade Place 4400 Harding Rd
Nashville, TN 37205-2290
Ph: 615-298-8200
Fx: 615-298-8213
philipc@ingrambarge.com

Robert M. Purgert, President
Energy Industries of Ohio
Park Center Plaza, Suite 200
6100 Oak Tree Blvd.
Independence OH 44131
Ph: 216-643-2952
Fx: 216-643-2901
purgert@energyinohio.com

William Raney, President
West Virginia Coal Association
PO Box 3923
Charleston, WV 25339
Ph: 304-342-4153

Bill Reid, Managing Editor
Coal News
106 Tamarack St.
Bluefield, WV 24701-4573
Ph: 304-327-6777
Fx: 304-327-6777
billreid007@comcast.net

John W. Rich, Jr., President
Gilberton Coal Company
Main Street
Gilberton, PA 17934

George Richmond, President
Jim Walter Resources, Inc.
PO Box 830079
Birmingham, AL 35283-0079
Ph: 205-481-6100
Fx: 205-481-6011
grichmond@jwrinc.com

James F. Roberts, President & CEO
Foundation Coal Company
999 Corporate Blvd, 3rd Fl.
Linthicum Heights, MD 21090
Ph: 410-689-7500 (7512)
Fx: 410-689-7511
jroberts@rag-american.com

Karen Roberts
Regional Manager, Coal Supply
Xcel Energy
PO Box 1261
Amarillo, TX 79105
Ph: 806-378-2505
Fx: 806-378-2790
karen.roberts@xcelenergy.com

James E. Rogers, Chairman, President, CEO
Cinergy Corporation
P.O. Box 960
Cincinnati, OH 45201
Ph:
Fx:

Daniel A. Roling, First Vice President
Merrill Lynch
Four World Finance Ctr., 19th Fl.
New York, NY 10080
Ph: 212-449-1905
Fx: 212-449-0546
daniel_roling@ml.com

William B. Schafer, III, Managing Director
NexGen Coal Services
710 Sunshine Canyon
Boulder, CO 80302
Ph: 303-417-417-0444
Fx: 303-417-0443
bschafer@nexgen-group.com

Debbie Schumacher
Women in Mining
915 Mayfair Dr.
Booneville, IN 47601-2319
Ph: 812-749-0040
wolfie66@msn.com

Michael J. Sierra, President & CEO
The Ventura Group
8550 Lee Highway, Ste 450
Fairfax, VA 22031-1515
Ph: 703-208-3303
Fx: 703-208-3305
msierra@theventuragroup.com

Ann E. Smith, Vice President
Charles River Associates
1201 F St. NW, Ste 700
Washington DC 20004
Ph: 202-662-3872
Fx: 202-662-3910
asmith@crai.com

Chester B. Smith, CEO
The Medford Group
5250 Galaxie Dr, Ste 8A
Jackson, MS 39206
Ph: 601-368-4583
Fx: 601-368-4541
chestervision@aol.com

Daniel D. Smith, President
Norfolk Southern Corporation
Three Commercial Place
Norfolk, VA 23510-9239
Ph: 757-629-2813
Fx: 757-664-5117
dzsmith@nscorp.com

Dwain F. Spencer, Principal
SIMTECHE
13474 Tierra Heights Rd.
Redding, CA 66003-8011
Ph: 530-275-6055
Fx: 530-275-6047
bwanadwain@aol.com

David F. Surber
Syndicated Environmental TV Producer/
Journalist Producer/Host
Make Peace With Nature TV Show
PO Box 15555
Covington, KY 41015-0555
Ph: 859-491-5000
Fx: 859-291-5000
surber@surber.com
surber@makepeacewithnature.com

Wes M. Taylor, President
Generation Business Unit
TXU Energy
1601 Bryan St., 42nd Fl.
Dallas, TX 75201-3411
Ph: 214-812-4699
Fx: 214-812-4758
wtaylor1@txu.com

Malcolm R. Thomas, Exec. Vice President
Charah Environmental, Inc.
Unit M, Suite 100
307 Townepark Circle
Louisville, KY 40243
Ph: 502-245-1353
Fx: 502-245-7398
thomasms@bellsouth.net
www.charah.com

Arvin Trujillo, Executive Director
Division of Natural Resources
The Navajo Nation
PO Box 9000
Window Rock, AZ 86515-9000
Ph: 928-871-6592/6593
Fx: 928-871-7040
dirdnr@email.com

Raja P. Upadhyay, President &
Principal Mine Engineer
Pincock, Allen & Holt
274 Union Boulevard, Suite 200
Lakewood, CO 80228
Ph: 303-986-6950
Fx: 303-987-8907
rpu@pincock.com

Kathy Walker, President
Elm Street Resources, Inc.
228 Main St., Suite 209
P.O. Box 1718
Paintsville, KY 41240
Ph: 606-789-4036 ext. 14
Fx: 606-789-4059
kwelmst@bellsouth.net

Steve Walker, President
Walker Machinery
PO Box 2427
Charleston, WV 25329
Ph: 304-949-6400
swalker@walker-cat.com

John L. Waltman, Vice President
DM&E Railroad
140 North Phillips Av, PO Box 1260
Sioux Falls, SD 57101
Ph: 605-782-1222
Fx: 605-782-1299
Cell: 605-321-8445
jwaltman@dmerail.com

Kathleen A. Walton
Soleil Securities
1230 Avenue of the Americas
Floor Two
New York, NY 10020
Ph: 212-632-5370
kwalton@soleilgroup.com

Jerome B. Weeden
Vice President, Generation
NIPSCO
801 East 86th Avenue
Merrillville, IN 46410
Ph: 219-647-5730
Fx: 219-647-5533
jbweeden@nisource.com

Alan W. Wendorf, Exec. Vice President
Fossil Power Technologies Group
Sargent & Lundy
55 E. Monroe St
Chicago, IL 60603
Ph: 312-269-6551
Fx: 312-269-3681
alan.w.wendorf@sargentlundy.com

James F. Wood, President & CEO
Babcock Power Inc.
One Corporate Place
55 Ferncroft Road, Suite 210
Danvers, MA 01923
Ph: 798-777-
Cell: 303-351-0766
Fx: 781-993-2499
powerjim@aol.com

NCC Staff

Robert A. Beck, Exec Vice President
robertabeck@natcoal.org
Larry B. Grimes, General Counsel
larrygrimes@cox.net
Richard A. Hall, CPA
rhall@natcoal.org
Pamela A. Martin, Executive Assistant
pmartin@natcoal.org
1730 M St NW, Ste 907
Washington DC 20036
Ph: 202-223-1191
Fx: 202-223-9031

APPENDIX C

The National Coal Council
2004 Coal Policy Committee Roster
(Georgia Nelson, Chair)

Robert O. Agbede, President & CEO
ATS Chester Engineers
639 Alpha Drive
Pittsburgh, PA 15238
Ph: 412-967-1900 Ext. 203
ragbede@atschester.com

James R. Aldrich, State Director
The Nature Conservancy
642 West Main Street
Lexington, KY 40508
Ph: 606-259-9655
Fx: 606-259-9678
jaldrich@tnc.org

Allen B. Alexander, President & CEO
Savage Companies
6340 South 3000 East #600
Salt Lake City, UT 84121
Ph: 801-944-6600
Fx: 801-261-8766
AllenA@SavageCompanies.com

Sy Ali, President
Clean Energy Consulting Corp.
7971 Black Oak Drive
Plainfield, IN 46168
Ph: 317-839-6617
Syali1225@aol.com

Barbara Farmer-Altizer, Executive Director
Eastern Coal Council
P.O. Box 858
Richlands, VA 24641
Ph: 276-964-6363
Fx: 276-964-6342
barb@netscope.net

Gerard Anderson, President & COO
DTE Energy Company
2000 2nd Avenue, 2409 WCB
Detroit, MI 48226-1279
Ph: 313-235-8880
Fx: 313-235-0537
andersong@dteenergy.com

Dan E. Arvizu, Ph.D.
Sr Vice President & CTO
Energy, Environment & Systems Businesses
CH2M Hill
9191 South Jamaica Street
Englewood, CO 80112
Ph: 720-286-2436
Fx: 720-286-9214
darvizu@ch2m.com

Richard Bajura, Director
National Research Center for Coal & Energy
West Virginia University
P.O. Box 6064, Evansdale Dr.
Morgantown, WV 26506-6064
Ph: 304-293-2867 (ext. 5401)
Fx: 304-293-3749
bajura@wvu.edu

Janos M. Beer
Professor of Chemical & Fuel Engineering
Dept. of Chemical Engineering
Massachusetts Institute of Technology
25 Ames St., Bldg. 66-548
Cambridge, MA 02139
Ph: 617-253-6661
Fx: 617-258-5766
jmbeer@mit.edu

Richard Benson, President
Caterpillar Global Mining
300 Hamilton Blvd., Ste. 300
Peoria, IL 61629-3810
Ph: 309-675-5127
Fx: 309-675-4777
Benson_Richard_a@cat.com

Jacqueline F. Bird, Director
OH Coal Development Ofc.
OH Air Quality Development Authority
50 W. Broad St., Suite 1718
Columbus, OH 43215
Ph: 614-466-3465
Fx: 614-752-9188
jbird@aqda.state.oh.us
www.ohioairquality.org

Sandy Blackstone
Natural Resources Attorney/Economist
8122 North Sundown Trail
Parker, CO 80134
Ph: 303-805-3717
Fx: 303-805-4342
sblackstone@ssbg.net

Robert L. Brubaker, Partner
Porter, Wright, Morris & Arthur
41 South High St.
Columbus, OH 43215
Ph: 614-227-2033
Fx: 614-227-2100
rbrubaker@porterwright.com

Michael Carey, President
Ohio Coal Association
17 S. High Street, Suite 215
Columbus, OH 43215-3413
Ph: 614-228-6336
Fx: 614-228-6349
info@ohiocoal.com
www.ohiocoal.com

Henry J. Cialone, Sr. Vice President
& General Manager/Energy Products
Battelle Labs
4606 Burbank Drive
Columbus, OH 43220
Ph: 614-457-7948
cialoneh@battelle.org

William Connors, Esquire
Centennial Power, Inc.
400 North 4th Street
Bismarck, ND 58501
Ph: 701-222-7965
Cell: 701-426-2913
Fx: 701-222-7877
bill.connors@mduresources
www.centennialenergy.com
www.mduresources.com

Steve Corwell
Sr. Vice President, Corporate Affairs
Indianapolis Power & Light
One Monument Circle
Indianapolis, IN 46204
Ph: 317-261-8240
Steve.corwell@aes.com

Kelly A. Cosgrove
Vice President, Marketing & Sales
Kennecott Energy Company
PO Box 3009
505 South Gillette Avenue
Gillette, WY 82716
Ph: 307-687-6053
Fx: 307-687-6009
cosgrovk@kenergy.com

Henry A. Courtright, Vice President
Power Generation & Distributed Resources
Electric Power Research Institute
3412 Hillview Ave.
Palo Alto, CA 94304
Ph: 650-855-8757
Fx: 650-855-8500
hcourtri@epri.com

Joseph W. Craft, III, President
Alliance Coal
1717 S. Boulder Ave.
Tulsa, OK 74119
Ph: 981-295-7602
Fx: 981-295-7361
josephc@arlp.com

E. Linn Draper, Jr.
Chairman, President & CEO
American Electric Power Company
One Riverside Plaza
Columbus, OH 43215
Ph: 614-223-1500
Fx: 614-223-1599
eldraper@aep.com

Michael D. Durham, President
ADA Environmental Solutions
8100 SouthPark Way, Unit B2
Littleton, CO 80120
Ph: 303-737-1727
Fx: 303-734-0330
miked@adaes.com

John Dwyer, President
Lignite Energy Council
1016 E. Owens Ave., Ste. 200
PO Box 2277
Bismarck, ND 58502-2277
Ph: 701-258-7117
Fx: 701-258-2755
jdwyer@lignite.com

Richard W. Eimer, Jr., Sr. Vice President
Dynegy, Inc.
2828 North Monroe St.
Decatur, IL 62526
Ph: 217-876-3932
Fx: 217-876-3913
rich_eimer@dynegy.com

Irl F. Engelhardt, Chairman & CEO
Peabody Energy
701 Market Street
St. Louis, MO 63101
Ph: 314-342-3400
Fx:
Email:

Andrea Bear Field, Partner
Hunton & Williams
1900 K St., NW, 12th Fl.
Washington, DC 20036
Ph: 202-955-1558
Fx: 202-778-2201
afield@hunton.com

Lance Fritz, Vice President &
General Manager/Energy
Union Pacific Railroad
1416 Dodge Street
Omaha, NE 68179
Ph: 402-271-5678
Fx: 402-271-3378
lfritz@up.com

Paul Gatzemeier
Vice President & General Manager
Centennial Energy Resources, LLC
122 East Broadway
Bismarck, ND 58501
Ph: 701-222-7985
Fx: 701-222-7877
paul.gatzemeier@mduresources.com

Janet Gellici, Executive Director
American Coal Council
2890 E. Northern Ave., Ste. B4
Phoenix, AZ 85028
Ph: 602-485-4737
Fx: 602-485-4847
jgellici@americancoalcouncil.org
www.americancoalcouncil.org

Patrick Graney, President
Petroleum Products, Inc.
500 Rivereast Dr.
Belle, WV 25015
Ph: 304-926-3000, ext. 113
Fx: 304-926-3009
pgraney@petroleumproductsinc.com

Alex E. S. Green
Graduate Research Professor Emeritus
University of Florida
Gainesville, FL 32611-6550
Ph: 352-392-2001
Fx: 352-392-2001 (call before sending)
aesgreen@ufl.edu

John Nils Hanson, President & CEO
Joy Global, Inc.
100 E. Wisconsin Ave., Ste. 2780
Milwaukee, WI 53202
Ph: 414-319-8500
Fx: 414-319-8510
jnha@hii.com

Clark D. Harrison, President
CQ, Inc.
160 Quality Ctr. Rd.
Homer City, PA 15748
Ph: 724-479-3503
Fx: 724-479-4181
clarkh@cq-inc.com
www.cq-inc.com

J. Brett Harvey, President & CEO
CONSOL Energy, Inc.
1800 Washington Rd.
Pittsburgh, PA 15241
Ph: 412-854-6671
Fx: 412-854-6613
bretthharvey@consolenergy.com

William Hoback, Bureau Chief
Office of Coal Development, State of Illinois
607 East Adams Street, CIPS-4
Springfield, IL 62701
Ph: 217-785-2001
Fx: 217-558-2647
bill_hoback@commerce.state.il.us

Warren J. Hoffman, Esquire
Frost Brown Todd LLC
250 W. Main St., Ste. 2700
Lexington, KY 40507-1749
Ph: 859-244-3320
Fx: 859-231-0011
whoffman@fbtlaw.com

Gerald (Jerry) A. Hollinden
Vice President, Power Sector Manager
URS Corporation
Waterfront Plaza Tower One
325 W. Main St., Ste. 1200
Louisville, KY 40202-4251
Ph: 502-217-1516
Fx: 502-569-3326
jerry_hollinden@urscorp.com

Christopher P. Jenkins
Sr. Vice President, Coal Service Group
CSX Transportation
500 Water Street
Jacksonville, FL 32202
Ph: 904-366-5693
Fx: 904-359-3443
chris_jenkins@csx.com

William Dean Johnson
Executive Vice President, General Counsel and Secretary
Progress Energy, Inc.
411 Fayetteville St. Mall
Raleigh, NC 27602
Ph: 919-546-6463
bill.johnson@pgnmail.com

Judy A. Jones, Commissioner
Public Utilities Commission of OH
180 East Broad St.
Columbus, OH 43215-3793
Ph: 614-644-8226
Fx: 614-466-7366
judy.jones@puc.state.oh.us
www.puc.state.oh.us

Dick Kimbler
PO Box 186
Danville, WV 25053
Ph: 304-369-3347

James R. Klauser
Sr. Vice President
Wisconsin Energy Corporation
231 West Michigan Street
Milwaukee, WI 53203
Ph: 414-221-4740
Fx: 414-221-3550
james.klauser@we-energies.com

Thomas G. Kraemer, Group Vice President
Burlington Northern Santa Fe Railway Co.
2650 Lou Menk Dr.
Ft. Worth, TX 76131-2830
Ph: 817-867-6242
Fx: 817-352-7940
thomas.kraemer@bnsf.com

Max L. Lake, President
Applied Sciences, Inc.
141 W. Xenia Ave, PO Box 579
Cedarville, OH 45314-0579
Ph: 937-766-2020 ext. 111
Fx: 937-766-5886
mllake@apsci.com

Steven F. Leer, President & CEO
Arch Coal Inc.
One City Place, Ste. 300
St. Louis, MO 63141
Ph: 314-994-2900
Fx: 314-994-2919
sleer@archcoal.com

David A. Lester, Executive Director
Council on Energy Resource Tribes
695 S. Colorado Blvd., Ste. 10
Denver, CO 80246-8008
Ph: 303-282-7576
Fx: 303-282-7584
ad@qwest.net

John T. Long, Sr. Vice President
Power Generation
Constellation Energy
111 Market Place, Suite 200
Baltimore, MD 21202
Ph: 410-230-4910
Fx: 410-230-4669
john.long@constellation.com

Jason Makansi, President
Pearl Street, Inc.
801 North Second Street, Suite 403
St. Louis, MO 63102
Ph: 314-621-0403
jmakansi@pearlstreetinc.com

James K. Martin
Vice President, Business Development
Dominion Energy
PO Box 26532
Richmond, VA 23261
Ph: 804-819-2176
Fx: 804-819-2219
james_k_martin@dom.com

Christopher C. Mathewson
Dept. of Geology & Geophysics
Texas A&M University, MS-3115
College Station, TX 77843-3115
Ph: 409-845-2488
Fx: 409-847-9313
mathewson@geo.tamu.edu

Kevin McGowan
(awaiting contact info)

Michael W. McLanahan, President & CEO
McLanahan Corporation
200 Wall Street
Hollidaysburg, PA 16648-0229
Ph: 814-695-9807
Fx: 814-695-6684
mmclanahan@mclanahan.com

Emmanuel R. Merle, President
Energy Trading Company
15 East Putnam Ave., #3210
Greenwich, CT 06830
Ph: 203-618-0161
Fx: 203-618-0454
thion@mindspring.com

Clifford R. Miercort, President & CEO
The North American Coal Corporation
14785 Preston Rd, Ste. 1100
Dallas, TX 75240-7891
Ph: 972-448-5402
Fx: 972-661-9072
clifford.miercort@nacoal.com

Jeffrey Miller, Managing Editor
Definitive Solutions Company, Inc.
8180 Corporate Park Dr., Ste 220
Cincinnati, OH 45242
Ph: 513-719-9150
Cell: 513-678-5456
Fx: 513-719-9130
jeff_miller@dsc-online.com

Michael G. Mueller, Vice President
Ameren Energy Fuels & Services Co.
PO Box 66149, Mail Code 611
St. Louis, MO 63166-6149
Ph: 314-554-4174
Fx: 314-206-1250
mmueller@ameren.com

Robert E. Murray, President & CEO
Murray Energy Corporation
29325 Chagrin Blvd., Ste. 300
Pepper Pike, OH 44122
Ph: 216-765-1240
Fx: 216-765-2654
bobmurray@coalsource.com

Ram G. Narula
Bechtel Fellow & Principal Vice President
Bechtel Power Corporation
5275 Westview Dr.
Frederick , MD 21703
Ph: 301-228-8804
Fx: 301-694-9043
rnarula@bechtel.com

Georgia Ricci Nelson, President
Midwest Generation EME, LLC
440 S. LaSalle St., Ste. 3500
Chicago, IL 60605
Ph: 312-583-6050
Fx: 312-583-4920
gnelson@mwgen.com

Mary Eileen O'Keefe, Director
KFx, Inc.
1362 North State Parkway
Chicago, IL 60610
Ph: 312-482-9701
Fx: 312-482-9703
maryeileenokeefe@aol.com

Umit Ozkan, Associate Dean for Research
College of Engineering & Professor of Chemical Engineering
Ohio State University
167 Hitchcock Hall, 2070 Neil Ave.
Columbus, OH 43210-1275
Ph: 614-292-6623 (Dept)
Ph: 614-292-2986 (College)
Fx: 614-292-9615
ozkan.1@osu.edu
www.che.eng.ohio-state.edu/facultypages/ozkan.html

Daniel F. Packer, President
Entergy New Orleans
PO Box 61000
New Orleans, LA 70161
Ph: 504-670-3622
Fx: 504-670-3605
dpacker@entergy.com

Thomas Pajonas, Managing Director
ALSTOM USA
2000 Day Hill Road
Windsor, CT 06095
Ph: 860-285-5035
Fx: 860-285-5425

Fredrick D. Palmer, Exec. Vice President
Peabody Energy
701 Market St.
St. Louis, MO 63101-1826
Ph: 314-342-7624
Fx: 314-342-7614
fpalmer@peabodyenergy.com

Earl B. Parsons, III, Vice President-Fuels
Southern Company
600 N. 18th St., 14N-8160, PO Box 2641
Birmingham, AL 35291
Ph: 205-257-6100
Fx: 205-257-0334
eabparso@southernco.com

Craig E. Philip, President & CEO
Ingram Barge Company
One Belle Meade Place 4400 Harding Rd
Nashville, TN 37205-2290
Ph: 615-298-8200
Fx: 615-298-8213
philipc@ingrambarge.com

Robert M. Purgert, President
Energy Industries of Ohio
Park Center Plaza, Suite 200
6100 Oak Tree Blvd.
Independence OH 44131
Ph: 216-643-2952
Fx: 216-643-2901
purgert@energyinohio.com

William Raney, President
West Virginia Coal Association
PO Box 3923
Charleston, WV 25339
Ph: 304-342-4153

Bill Reid, Managing Editor
Coal News
106 Tamarack St.
Bluefield, WV 24701-4573
Ph: 304-327-6777
Fx: 304-327-6777
billreid007@comcast.net

John W. Rich, Jr., President
Gilberton Coal Company
Main Street
Gilberton, PA 17934
Ph:
Fx:
Email:

George Richmond, President
Jim Walter Resources, Inc.
PO Box 830079
Birmingham, AL 35283-0079
Ph: 205-481-6100
Fx: 205-481-6011
grichmond@jwrinc.com

James F. Roberts, President & CEO
Foundation Coal Company
999 Corporate Blvd, 3rd Fl.
Linthicum Heights, MD 21090
Ph: 410-689-7500 (7512)
Fx: 410-689-7511
jroberts@rag-american.com

Karen Roberts
Regional Manager, Coal Supply
Xcel Energy
PO Box 1261
Amarillo, TX 79105
Ph: 806-378-2505
Fx: 806-378-2790
karen.roberts@xcelenergy.com

James E. Rogers, Chairman, President, CEO
Cinergy Corporation
P.O. Box 960
Cincinnati, OH 45201
Ph:
Fx:

Daniel A. Roling, First Vice President
Merrill Lynch
Four World Finance Ctr., 19th Fl.
New York, NY 10080
Ph: 212-449-1905
Fx: 212-449-0546
daniel_roling@ml.com

William B. Schafer, III, Managing Director
NexGen Coal Services
710 Sunshine Canyon
Boulder, CO 80302
Ph: 303-417-417-0444
Fx: 303-417-0443
bschafer@nexgen-group.com

Debbie Schumacher
Women in Mining
915 Mayfair Dr.
Booneville, IN 47601-2319
Ph: 812-749-0040
wolfie66@msn.com

Michael J. Sierra, President & CEO
The Ventura Group
8550 Lee Highway, Ste 450
Fairfax, VA 22031-1515
Ph: 703-208-3303
Fx: 703-208-3305
msierra@theventuragroup.com

Ann E. Smith, Vice President
Charles River Associates
1201 F St. NW, Ste 700
Washington DC 20004
Ph: 202-662-3872
Fx: 202-662-3910
asmith@crai.com

Chester B. Smith, CEO
The Medford Group
5250 Galaxie Dr, Ste 8A
Jackson, MS 39206
Ph: 601-368-4583
Fx: 601-368-4541
chestervision@aol.com

Daniel D. Smith, President
Norfolk Southern Corporation
Three Commercial Place
Norfolk, VA 23510-9239
Ph: 757-629-2813
Fx: 757-664-5117
dzsmith@nscorp.com

Dwain F. Spencer, Principal
SIMTECHE
13474 Tierra Heights Rd.
Redding, CA 66003-8011
Ph: 530-275-6055
Fx: 530-275-6047
bwanadwain@aol.com

David F. Surber
Syndicated Environmental TV Producer/
Journalist Producer/Host
Make Peace With Nature TV Show
PO Box 15555
Covington, KY 41015-0555
Ph: 859-491-5000
Fx: 859-291-5000
surber@surber.com
surber@makepeacewithnature.com

Wes M. Taylor, President
Generation Business Unit
TXU Energy
1601 Bryan St., 42nd Fl.
Dallas, TX 75201-3411
Ph: 214-812-4699
Fx: 214-812-4758
wtaylor1@txu.com

Malcolm R. Thomas, Exec. Vice President
Charah Environmental, Inc.
Unit M, Suite 100
307 Townepark Circle
Louisville, KY 40243
Ph: 502-245-1353
Fx: 502-245-7398
thomasms@bellsouth.net
www.charah.com

Arvin Trujillo, Executive Director
Division of Natural Resources
The Navajo Nation
PO Box 9000
Window Rock, AZ 86515-9000
Ph: 928-871-6592/6593
Fx: 928-871-7040
dirdnr@email.com

Raja P. Upadhyay, President &
Principal Mine Engineer
Pincock, Allen & Holt
274 Union Boulevard, Suite 200
Lakewood, CO 80228
Ph: 303-986-6950
Fx: 303-987-8907
rpu@pincock.com

Kathy Walker, President
Elm Street Resources, Inc.
228 Main St., Suite 209
P.O. Box 1718
Paintsville, KY 41240
Ph: 606-789-4036 ext. 14
Fx: 606-789-4059
kwelmst@bellsouth.net

Steve Walker, President
Walker Machinery
PO Box 2427
Charleston, WV 25329
Ph: 304-949-6400
swalker@walker-cat.com

John L. Waltman, Vice President
DM&E Railroad
140 North Phillips Av, PO Box 1260
Sioux Falls, SD 57101
Ph: 605-782-1222
Fx: 605-782-1299
Cell: 605-321-8445
jwaltman@dmerail.com

Kathleen A. Walton
Soleil Securities
1230 Avenue of the Americas
Floor Two
New York, NY 10020
Ph: 212-632-5370
kwalton@soleilgroup.com

Jerome B. Weeden
Vice President, Generation
NIPSCO
801 East 86th Avenue
Merrillville, IN 46410
Ph: 219-647-5730
Fx: 219-647-5533
jbweeden@nisource.com

Alan W. Wendorf, Exec. Vice President
Fossil Power Technologies Group
Sargent & Lundy
55 E. Monroe St
Chicago, IL 60603
Ph: 312-269-6551
Fx: 312-269-3681
alan.w.wendorf@sargentlundy.com

James F. Wood, President & CEO
Babcock Power Inc.
One Corporate Place
55 Ferncroft Road, Suite 210
Danvers, MA   01923
Ph: 798-777-
Cell: 303-351-0766
Fx: 781-993-2499
powerjim@aol.com

NCC Staff

Robert A. Beck, Exec Vice President
robertabeck@natcoal.org
Larry B. Grimes, General Counsel
larrygrimes@cox.net
Richard A. Hall, CPA
rhall@natcoal.org
Pamela A. Martin, Executive Assistant
pmartin@natcoal.org
1730 M St NW, Ste 907
Washington DC 20036
Ph: 202-223-1191
Fx: 202-223-9031

APPENDIX D

The National Coal Council 2004 Study Work Group

Sy Ali, Clean Energy Consulting Corporation; Ph: 317-839-6617; syali1335@aol.com

Tom Altmeyer, Arch Coal, Inc.; Ph: 202-333-5265; taltmeyer@archcoal.com

Dan Arvizu, CH2M Hill; Ph: 270-286-2436; darvizu@ch2m.com

Eric Balles, Babcock Borsig Power, Inc.; Ph: 508-854-4004; eballes@babcockpower.com

Janos Beer, MIT; ph: 617-253-6661; jmbeer@mit.edu

George Booras, EPRI; ph: 650-855-2471; gbooras@epri.com

Rob Brubaker, Porter, Wright, Morris & Arthur; Ph; 614-227-2033; rbrubaker@porterwright.com

Frank Burke, CONSOL R&D; Ph: 412-854-6676; frankburke@consolenergy.com

Fred Bush, Savage Companies; Ph: 801-263-9400; fredb@savagecompanies.com

Hank Courtright, EPRI; Ph: 650-855-8757; hcourtri@epri.com

Stu Dalton, EPRI; Ph: 650-855-2000; sdalton@epri.com

David Denton, Eastman Gasification Services Company; Ph: 423-229-6559; dldenton@eastman.com

Bill DePriest, Sargent & Lundy; Ph: 312-269-6678; William.depriest@sargentlundy.com

E Linn Draper, Jr., AEP; Ph: 614-223-1500; eldraper@aep.com

Richard Eimer, Dynegy Marketing & Trade; Ph: 217-876-3932; rich_eimer@dynegy.com

Joel Friedlander, The North American Coal Corporation; joel.friedlander@nacoal.com

Janet Gellici, American Coal Council; Ph: 602-485-4737; jgellici@americancooalcouncil.org

Tom Grahame, DOE; 202-586-7149; Thomas.graham@hq.doe.gov

Mike Gregory, The North American Coal Corporation; Ph: 972-448-5443; mike.gregory@nacoal.com

Larry Grimes, The National Coal Council; Ph: 202-223-1191; larrygrimes@cox.net

Jerry Hollinden, URS Corporation; Ph: 502-217-1516; jerry_hollinden@urscorp.com

Neville Holt, EPRI; Ph: 650-855-2503; nholt@epri.com

Klaus Lambeck, Public Utilities Commission of Ohio; ph: 614-644-8244; klaus.lambeck@puc.state.oh.us

Steve Jenkins, URS Corporation; Ph: 813-397-7807; steve_Jenkins@urscorp.com

Judy Jones, Public Utilities Commission of Ohio; Ph: 614-644-8226; judy.jones@puc.state.oh.us

Bob Kane, DOE; Ph: 202-586-4753; Robert.kane@hq.doe.gov

Jeff Knitter, WeEnergies; Jeff.knitter@we-energies.com

Ron Litzinger, Edison Mission Energy; Ph: 949-798-7912; rlitzinger@edisonmission.com

John Long, Constellation Energy; Ph: 410-230-4910; john.long@constellation.com

Mike Mudd, AEP; Ph 614-716-1585; mjmudd@aep.com

Ram Narula, Bechtel Power Corporation; Ph: 301-228-8804; rnarula@bechtel.com

Georgia Nelson, Midwest Generation; Ph: 312-583-6015; gnelson@mwgen.com

Fredrick Palmer, Peabody Energy; Ph: 314-342-7624; fpalmer@peabodyenergy.com

Jack Parkes, EPRI; ph: 650-855-2128; jparkes@epri.com

Bob Pearson, CH2M Hill; Ph: 720-286-5056; rpearson@ch2m.com

Robert Purgert, Energy Industries of Ohio; Ph: 216-643-2952; purgert@energyinohio.com

Peter Rigby, Standard & Poor's; Ph: 212-438-2085; peter_rigby@standardandpoors.com

Lars Scott, Peabody Energy; Ph: 314-342-7594; lscott@peabodyenergy.com

John Vella, Edison Mission Energy; Ph: 949-798-7935; jvella@edisonmission.com

Jerry Weeden, NiSource; Ph: 219-647-5730; jbweeden@nisource.com

Kim Wissman, Public Utilities Commission of Ohio; ph: 614-644-6692; kim.wissman@puc.state.oh.us

Mona Yee , Fitch Ratings; ph: 202-908-0557; mona.yee@fitchratings.com

APPENDIX E

Correspondence Between The National Coal Council and the U.S. Department of Energy

The Secretary of Energy
Washington, DC 20585

December 3, 2003

Mr. Wes Taylor
Chairman
National Coal Council, Inc.
1730 M Street, NW, Suite 907
Washington, DC 20036

Dear Mr. Taylor:

Thank you for your letter requesting approval to conduct a study to determine options for the expeditious construction and operation of new, coal-based electricity generation plants to maintain the Nation's fuel diversity.

As stated in the May 2001 National Energy Policy Report, the Administration believes that it is in the best interest of the Nation to have a diverse fuel mix for the generation of electricity. Therefore, the Department is interested in knowing which opportunities could expedite the construction of new coal-based electricity generation. Thus, I request that the NCC undertake this important study.

While emissions from coal fired power plants have been dramatically reduced over the last two decades, coal plants still evoke public concerns which hinder the use of this valuable energy resource in power generation. Accordingly, I also request that the study examine opportunities and incentives for additional emissions reduction including evaluating replacing the oldest portion of our coal fired power plant fleet with more efficient and lower emitting coal-fired plants.

We believe that your membership represents a broad spectrum of senior level industry, State and public interest organizations, and is well positioned to carry out this request. We also believe that this report will serve as a blueprint for industry while acting as a guide to promote the construction of new coal-fired facilities.

I am designating Mr. Robert G. Card, Under Secretary for Energy, Science and Environment, and Mr. Carl Michael Smith, Assistant Secretary for Fossil Energy, to represent me while the study is being conducted. My thanks to the Council for its efforts to assist the Department in defining the scope of the study. We look forward t receiving the report upon its completion.

Sincerely,

Spencer Abraham

cc: Under Secretary Robert G. Card
Assistant Secretary Carl Michael Smith
Mr. Mark R. Maddox
Mr. George Rudins

APPENDIX F

Correspondence from Industry Experts

Robert Beck

From:	Pam Martin
Sent:	Wednesday, December 08, 2004 11:24 AM
To:	Robert Beck
Subject:	FW: Omission about Federal Credit in NCC "Expedite" report; attachment

Credit insert for NCC study r2...

Here ya go!

Subject: Re: Omission about Federal Credit in NCC "Expedite" report; attachment

FROM: Andy Paterson 619-807-3267

Bob,
Mea culpa, I just grabbed the wrong file in the previous e-mail. Here is the insert (about a page and a half); let me know if you need to trim it.

For the record several of the working group members were among the respondents on the risk ratings: AEP, Bechtel, Cinergy, EPRI, GTC, Peabody, CONSOL, DOE, WE Energy, Southern, Tampa Electric; so there is solid corroboration with your team.

Anxious to help with the final report distribution... when we see who is the new Secretary. Thanks! Andy

[Section 3: Clean Coal Power Incentives – Existing and Proposed (starting page 36)]

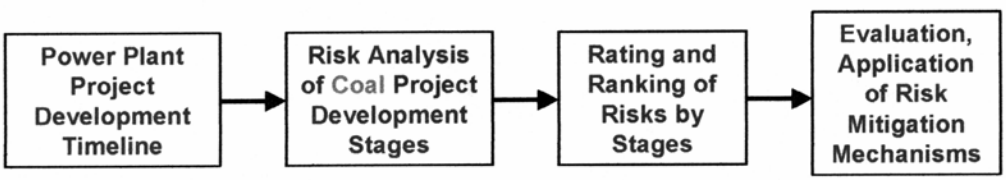
[insert near bottom of page 41 before "Conclusions", as part of studies of incentives]

Negotiated Federal Credit

The Federal Credit Reform Act (FCRA, 1990) enables federal agencies to utilize credit instruments (e.g., direct loans, loan guarantees, lines of credit) to assist qualifying private projects, such as early commercial projects that use advanced energy technologies, and establishes clear rules (as specified under OMB Circular A-129) for federal budget scoring of such projects. Independent estimates of private credit rating agencies of project default rate and recovery prospects are central to the process of negotiating federal credit support. The primary advantages arise from the negotiation of terms of credit instruments that are tailored to specific commercial risks. With negotiation, industry moves ahead on projects only where federal budget exposure is optimized. Tax credits or even loan guarantees with levels set by Congress fail to optimize federal budget resources by foregoing the negotiated credit process. Moreover, public power entities cannot utilize federal loan guarantees because of their tax status.

Several agencies now utilize federal credit to provide assistance to capital-intensive projects, including the Department of Transportation (DOT), the Agency for International Development (AID), and the Department of Agriculture (USDA). While the only credit tool that the Department of Energy (DOE) has used is loan guarantees, the Department could use federal credit to more effectively co-manage critical business risks with the private sector on projects using advanced energy technologies, such as clean coal power plants.

Risk Framework for Targeting Incentives



A DOE team led by David Berg of the Office of Policy & International Affairs assessed key stakeholders' perceptions of risks facing early commercial deployments of clean coal power via a questionnaire process. Senior-level respondents were drawn from the entire transaction chain (i.e., technology vendors, engineering companies, the financial community, potential owner / operators, energy regulators, environmental regulators) and the research community. The assessment explored views about three broad areas of risk (technical and operating, regulatory, and market) and included 29 specific risks.

Participants were asked to rate on a five-point scale both the *probability* of a particular risk event occurring and the *severity of the impact* by the event on the commercial prospects of a clean coal unit. The product of the probability and severity constitutes a risk rating. The two dimensions of each risk rating help better characterize the nature of these risks. They also improve precision in designing remedies, policies, and incentives for addressing the highest rated risks.

Two risks rated highest:

1. Higher capital cost of IGCC units in comparison to traditional pulverized coal combustion units.

2. excessive downtime or reliability problems due to technical complexities of the gasification process for power generation.

Buyers believe that clean coal plants will carry roughly 20% to 25% higher capital costs compared with subcritical conventional coal-based power plants (see analysis by EPRI and others). Buyers generally believe that there will be an extended "shake-out" period—as much as 3 years—to optimize operation of an IGCC. Of note, respondents rated the probability of high capital cost being a factor at 4.4 out of 5.0, or a near certainty, for early plants. Lack of standardization of IGCC systems rated high enough to be considered a factor in perceptions about downtime risk. Skepticism was apparent about whether future state and federal incentives will be adequate to justify investment in early IGCC plants (including the potential to monetize IGCC's advantage for "carbon capture" or emission avoidance).

The following specific risks were rated highest (33 respondents participating):

	Q#	Risk Area for Clean Coal Highest Risks	A Probability	B Severity	A x B Rating
Technical	1	High capital cost	4.4	4.7	**20.4**
	3	Excessive downtime	3.7	4.4	**16.5**
	5	Lack of standardization	3.7	3.5	**12.9**
Regulatory	18	No state policies for IGCC	3.3	3.7	**12.1**
	19	Nat'l. policy on IGCC lags	3.4	4.2	**14.4**
Market	26	PUC rate approval fails	2.9	4.6	**13.2**
	27	Financing difficult	3.7	4.5	**16.5**

(Source: compiled by Andrew Paterson, Environmental Business International)

Targeting Key Risks with Federal Credit

In a credit-based assistance program, DOE would negotiate credit-based financial assistance targeted on just the business risks that limit commercial decisions to build early commercial clean coal plants. Like tax credits, such financial assistance could provide a significant boost to project financial returns, but it would do so in a way that is more risk-targeted and inexpensive. Tax credits do not cover downtime risk.

The credit process combines federal and private evaluation of project creditworthiness, including evaluation of revenue streams dedicated to repayment of federal credit support. Based on these evaluations of qualifying energy projects, DOE would negotiate credit assistance (e.g., direct loans, lines of credit, loan guarantees) for individual projects to tailor its support to the risks that deter private investment. Negotiations would address the size and terms of financial assistance needed to mitigate these specific risks.

Credit assistance can optimize the use of DOE resources by tailoring assistance to the need of individual projects, reducing budget scoring and, therefore, multiplying the Department's impact in addressing market failures. Tailored credit assistance maximizes impact on projects and minimizes the cost of assistance; in this regard, credit differs from traditional assistance mechanisms.

In gaining authority and appropriations for credit assistance to capital-intensive projects, DOE would build on the successful experience of other agencies, including AID, DOT, and USDA. For example, DOT's TIFIA program has provided credit assistance to 11 projects since 1999. These projects, with a total cost of $15.4 billion, received $3.5 billion of direct loans, loan guarantees, and lines of credit at an average budget scoring rate of about 5%. All of the projects have been built and there have been no defaults on federal credit; in fact, one loan was repaid in full ahead of schedule.

APPENDIX G

Acknowledgements

The members of the Council wish to acknowledge, with sincere thanks, the special assistance received from the following persons in connection with various phases of the development of this report:

Julie Clendenin, *Editor*

Pam Martin, *NCC Staff*